HB

177

(FILE 2)

5/2/07

Presentation to the Alaska Legislature House Finance Committee May 2, 2007

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- How is gas generally taxed under the PPT? What are the PPT credit implications of gasline work?

- Same as oil (almost) – on net value
- Investment downstream of the point of production not eligible for credits

How is gas taxed under the PPT

- 43.55.011
- (e) 22.5% of net value
- (f) North Slope floor triggered by oil price
- (g) & (h) Progressivity triggered by single taxpayer net value
- (i) Private royalty 1.67% for gas – 1/3 of oil
- (j) Cook Inlet Ceiling

AS 43.55.011 (e) 22.% of net value

- Total upstream costs are deducted from the revenue streams from oil and gas sales.

- Gas Revenue Exclusion (GRE) mechanism discussed in 2006 is an administratively simple way of adjusting the effective rate without changing the nominal rate or making lots of allocations.

43.55.011(f) North Slope floor triggered by oil price

- Alternative floor just applicable to North Slope Oil and Gas is triggered by oil price.
  - Consider future if Prudhoe Bay is producing 250,000 bbls oil and 3 bcf of gas.
  - If the heating value is 1,000,000 btu per mcf, that translates to the equivalent of 500,000 bbls a day – so 1/3 of the field's production will be used to set the trigger.

- Question 3. How does PPT progressivity work on gas and what is it's link to oil?

AS 43.55.011(g) & (h) Progressivity triggered by single taxpayer net value

- Progressivity is determined for each taxpayer on its total mix of oil and gas and all upstream costs
- Calculated on a monthly basis – monthly upstream costs are 1/12 of total annual costs
- Example – Next slide
  - Prices April 27 2007,
  - 1,000 btu per mcf,
  - equal mix of boe gas and oil

AS 43.55.011(g) & (h) progressivity triggered by single taxpayer net value

	Oil		Gas		Gas BOE		Taxpyr Ave
Dest Price	63.76		7.32				
Downstream Adj	(5.00)		(3.00)				
Gross Value	58.76		4.32	6.00	25.92		
Upstream Adj	(7.00)				(7.00)		
Net Value	51.76				18.92		35.34
.011(h) limit	(40.00)				(40.00)		(40.00)
Price Index	11.76				N/a		N/a
.011(g) factor	0.0025				0.0025		0.0025
Progressivity %	2.940%				N/a		N/a

Dollar/bbl progressivity Charge at various Destination values and net deductions

Per barrel Progressivity Charge							
Per Barrel Costs	Monthly Average Destination Value per bbl in Dollars						
	50	55	60	65	70	75	80
5	0.56	1.25	2.06	3.00	4.06	5.25	6.56
6	0.44	1.10	1.89	2.80	3.84	5.00	6.29
7	0.32	0.96	1.72	2.61	3.62	4.76	6.02
8	0.21	0.82	1.56	2.42	3.41	4.52	5.76
9	0.10	0.69	1.40	2.24	3.20	4.29	5.50
10		0.56	1.25	2.06	3.00	4.06	5.25
11		0.44	1.10	1.89	2.80	3.84	5.00
12		0.32	0.96	1.72	2.61	3.62	4.76
13		0.21	0.82	1.56	2.42	3.41	4.52
14		0.10	0.69	1.40	2.24	3.20	4.29
15			0.56	1.25	2.06	3.00	4.06
16			0.44	1.10	1.89	2.80	3.84
17			0.32	0.96	1.72	2.61	3.62
18			0.21	0.82	1.56	2.42	3.41
19			0.10	0.69	1.40	2.24	3.20
20				0.56	1.25	2.06	3.00

AS 55.43.011(i) Private Royalty 1.67% of gross for gas

- This is one third the rate for oil which is 5% of gross.

AS 43.55.011(j) Cook Inlet Ceiling

- No direct effect on North Slope gas
- Expires in 2022
- If gas line is built from North Slope to Cook Inlet may want to consider effect of differential rates of taxation
- Ceiling potentially different for each producer:
  - Average (15 AAC 55.440) 4.947% of $3.585 per mcf.

- Are PPT gas credits applicable to the GTP in the AGIA bill?

- Under PPT – the GTP is not eligible for credits.

Only Upstream Costs Qualify as Credits

- AS 43.55.023 (a) "…may take a tax credit for a qualified capital expenditure… in the amount of 20 percent of that expenditure;"

- AS 43.55.023 (k)"…'qualified capital expenditure'…means…an expenditure that is a lease expenditure under AS 43.55.165 and is…treated as a capitalized expenditure under 26 U.S.C. (Internal Revenue Code)

Only Upstream Costs Qualify as Credits

- AS 43.55.165 (a) "…a producer's lease expenditures for a calendar year are the ordinary and necessary costs upstream of the point of production of oil and gas …and that are the direct costs of exploring for developing, or producing oil or gas…

Where is the point of Production?

- In AS 43.55.900
- (21) gas processing
- (23) gas treatment
- (27) point of production
- Are defined so that gas processing is upstream of the point of production and gas treatment is downstream of the point of production.

PPT Definitions: Point of Production

- AS 43.55.011(27) "point of production" means
- (A) for oil…
- (B) for gas, other than gas described in (c) of this paragraph that is
- (i) not subjected to or recovered by mechanical separation or run through a gas processing plant, the first point where the gas is accurately metered;
- (ii) subjected to or recovered by mechanical separation but not run through a gas processing plant, the first point where the gas is accurately metered after completion of mechanical separation;

PPT Definitions: Point of Production

- AS 43.55.011(27) "point of production" means
- (B) for gas…
- (iii) run through a gas processing plant, the first point where the gas is accurately metered downstream of the plant;
- (C) for gas run through an integrated gas processing plant and gas treatment facility that does not accurately meter the gas after the gas processing and before the gas treatment, the first point where the gas processing is completed or where gas treatment begins, whichever is further upstream.

PPT Definitions: Gas Processing

- AS 43.55.011 (21) "gas processing"
- (A) means processing a gaseous mixture of hydrocarbons
- (i) by means of absorption, adsorption, externally applied refrigeration, artificial compression followed by adiabatic expansion using the Joule-Thomson effect, or another physical process that is not mechanical separation; and
- (ii) for the purpose of extracting and recovering liquid hydrocarbons [producing ngls/oil];
- (B) does not include gas treatment

PPT Definitions: Gas Treatment

- AS 43.55.011 (23) "gas treatment"
- (A) means conditioning gas and removing from gas nonhydrocarbon substances for the purpose of rendering the gas acceptable for tender and acceptance into a gas pipeline system.
- (B) includes incidentally removing liquid hydrocarbons from the gas

PPT Definitions: Gas Treatment

- AS 43.55.011 (23) "gas treatment" (cont.)
- (C) does not include
  - (i) dehydration required to facilitate the movement of gas from the well to the point where gas processing takes place;
  - (ii) the scrubbing of liquids from gas to facilitate gas processing.

Under Current law:

- Gas Processing
- Starts with gaseous mixture of hydrocarbons, and produces natural gas liquids and gas by removing the hydrocarbon liquids.
- Gas treatment
- Starts with produced gas and removes nonhydrocarbons (including incidental hydrocarbons) to prepare the gas for tender to the pipeline. Nothing is produced.

AGIA Definitions: Gas Processing

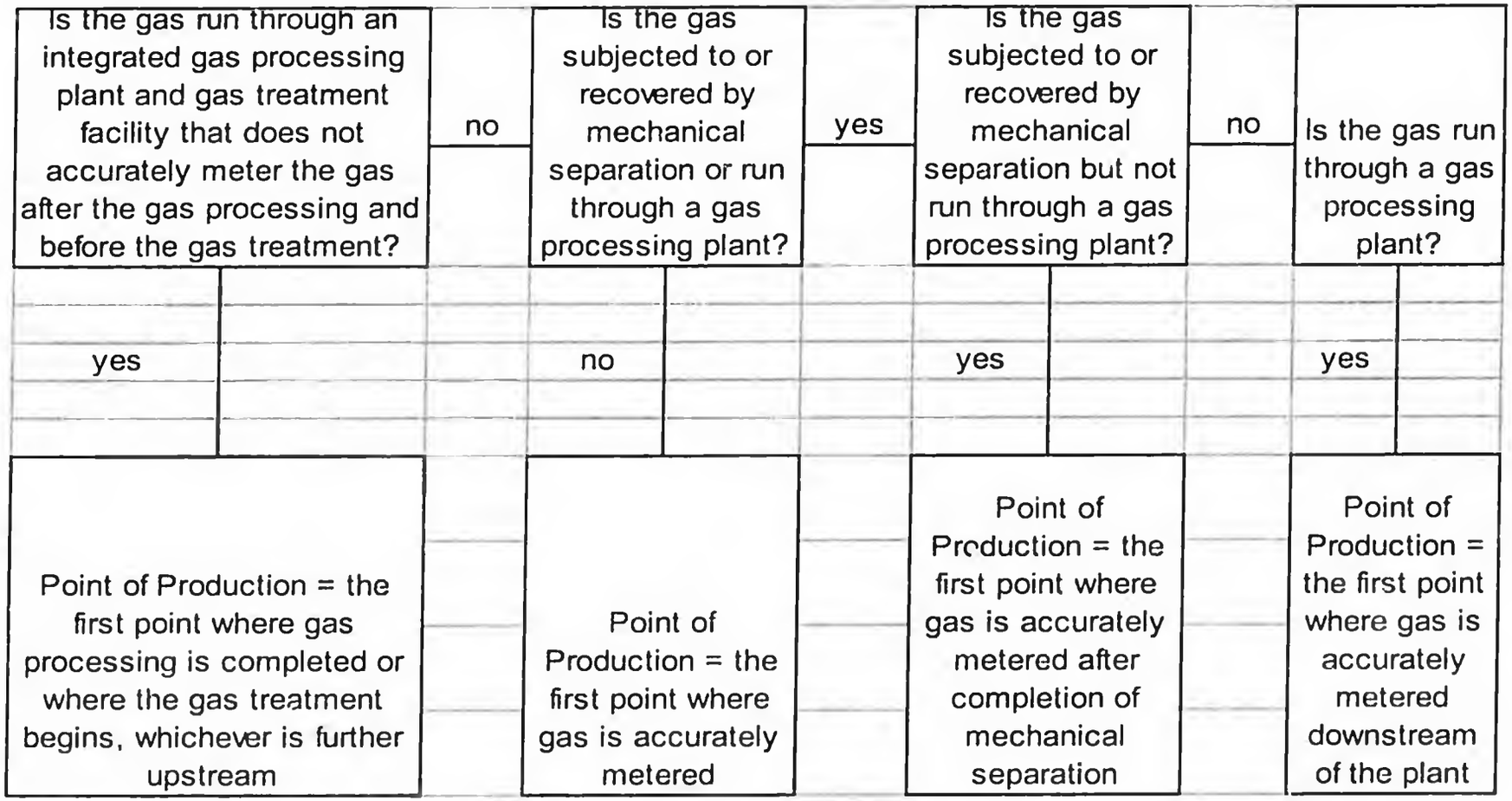
- AS 43.55.900 (7) "gas processing" means the treatment of gas downstream of the point of production to extract natural gas liquids. CSHB 177(RES)
- AS 43.55.900 (7) "gas processing" means post-production treatment of gas to extract natural gas liquids. CSSB 104(JUD)

AGIA Definitions: Gas Processing

- Suggested Definition

- AS 43.55.900 (7) "gas processing" has the same meaning as "gas processing" in AS 43.55.900 (21)

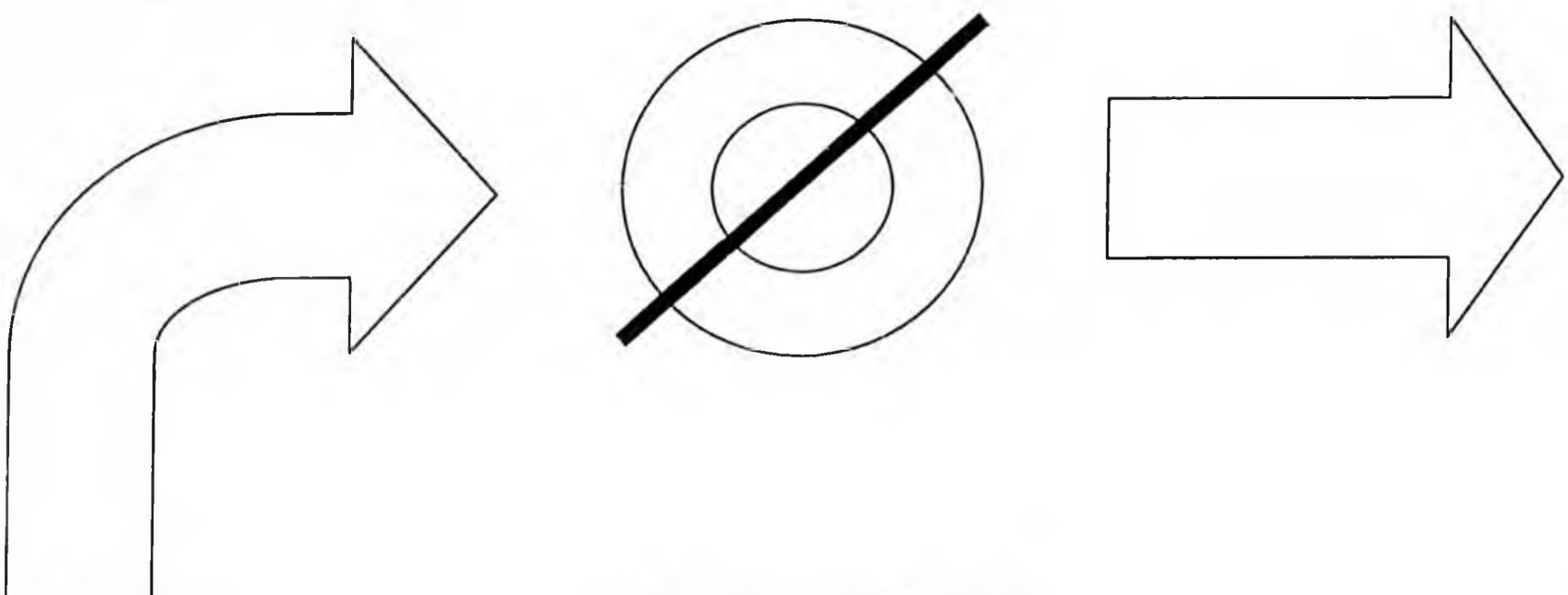
PPT Point of Production for Gas



Gas Point of Production

Gas not run through a gas processing point or subject to mechanical separation

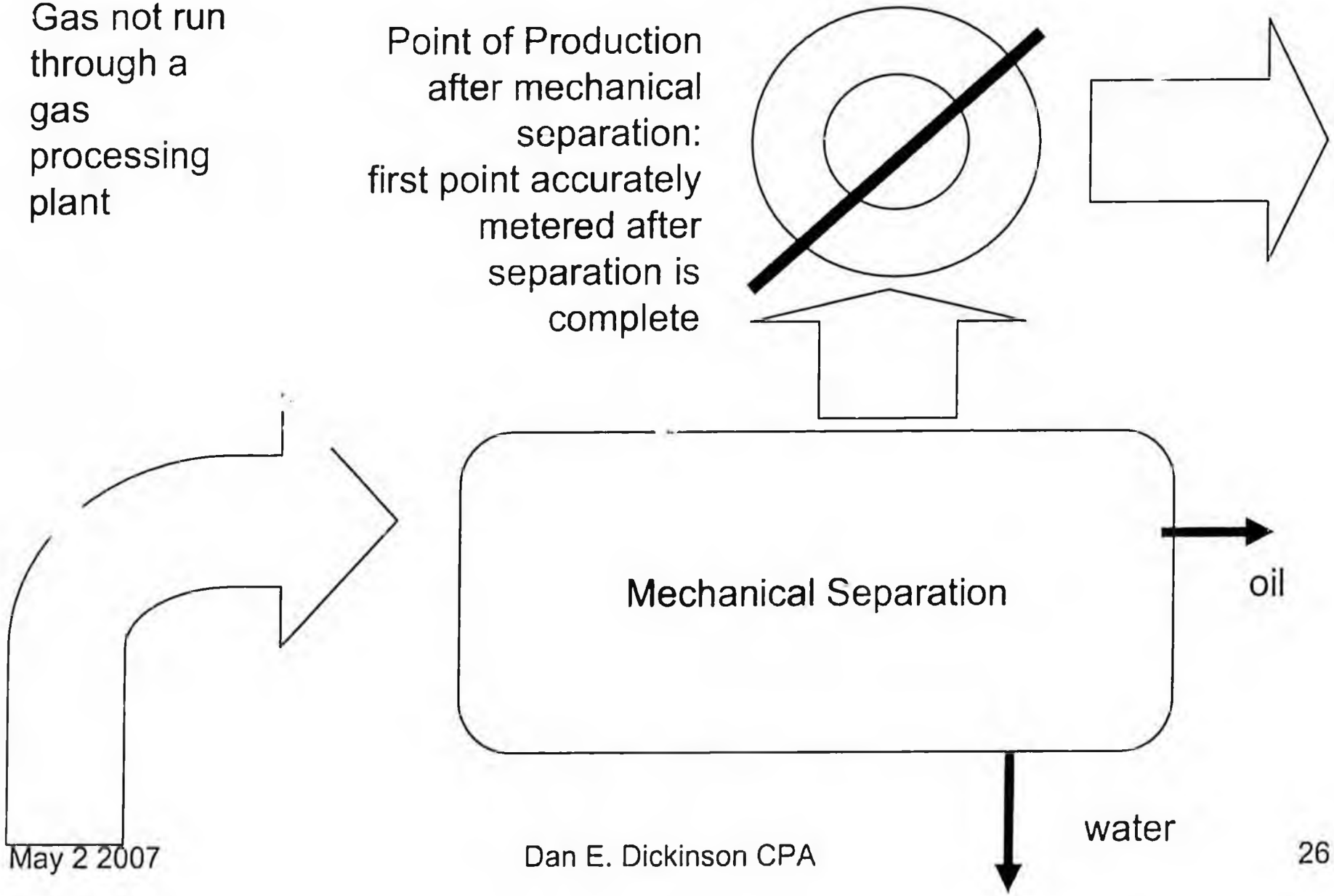
Point of Production: first point accurately metered



Gas Point of Production

Gas not run through a gas processing plant

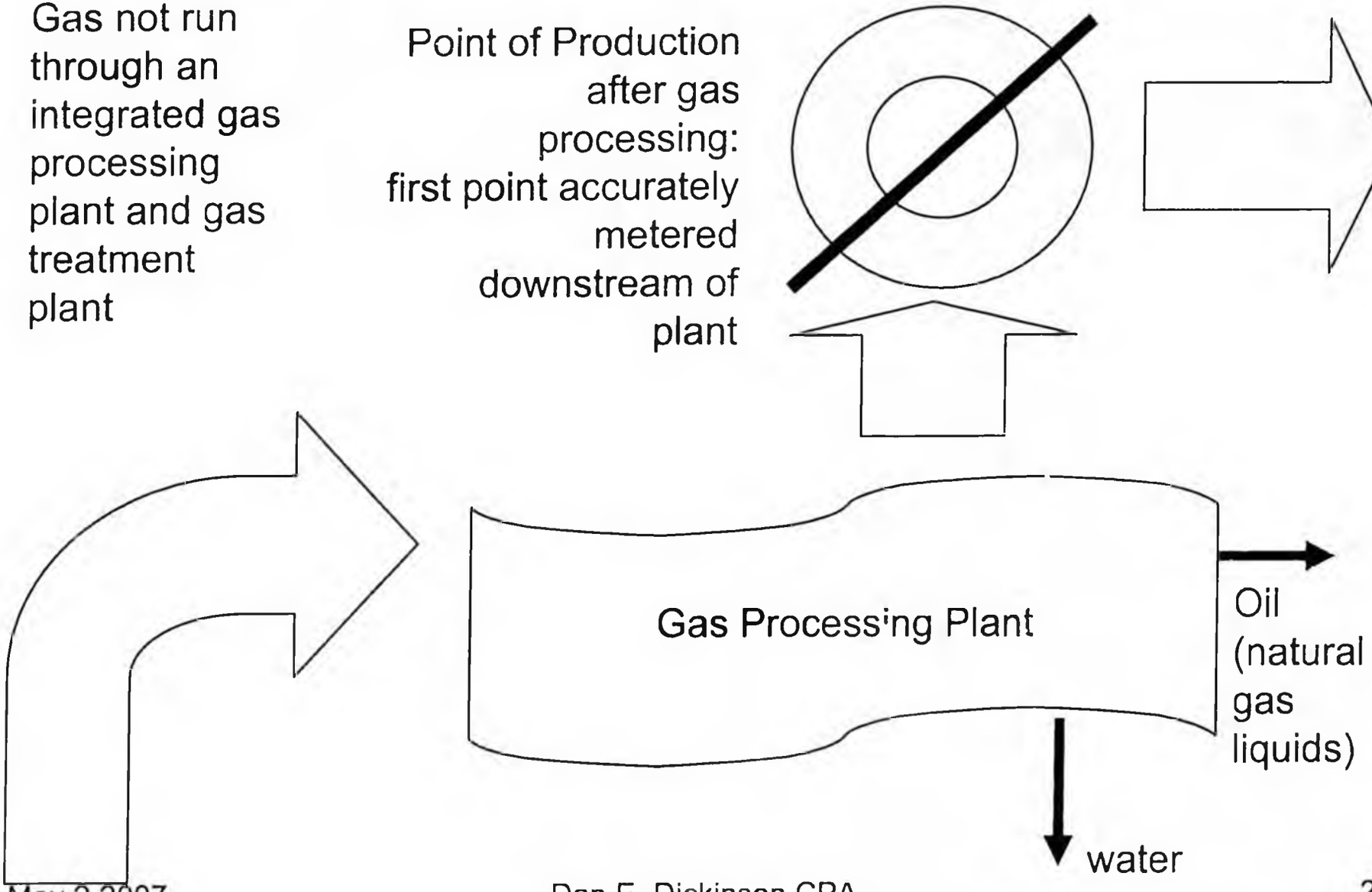
Point of Production after mechanical separation: first point accurately metered after separation is complete



Gas Point of Production

Gas not run through an integrated gas processing plant and gas treatment plant

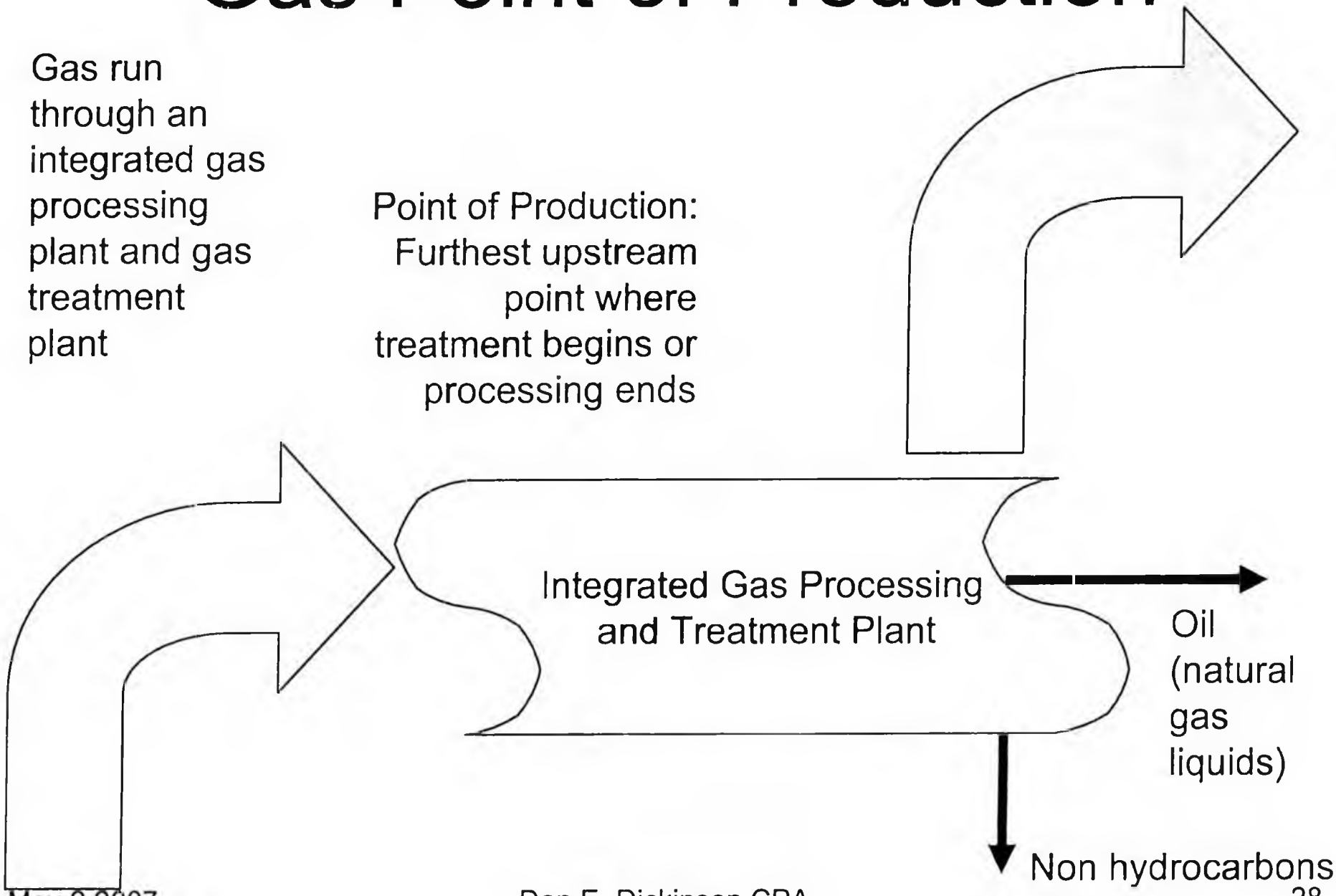
Point of Production after gas processing: first point accurately metered downstream of plant



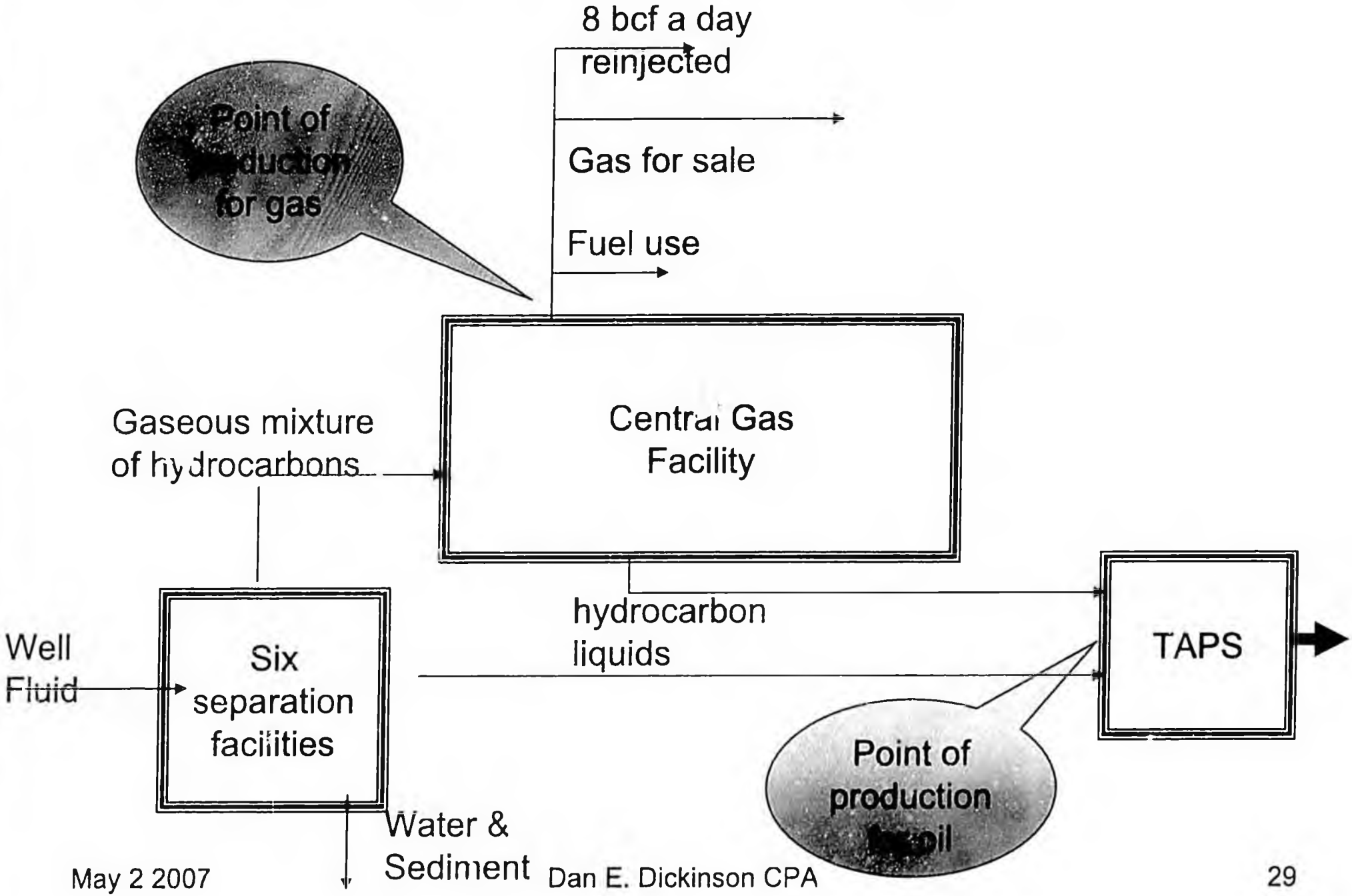
Gas Point of Production

Gas run through an integrated gas processing plant and gas treatment plant

Point of Production: Furthest upstream point where treatment begins or processing ends



Prudhoe Bay: Point of Production under the PPT



North Slope Central Gas Facility

- On the Alaska North Slope the Central Gas Facility is a gas processing plant, which sends natural gas liquids which are produced at the TAPS inlet:

- AS 43.55.009 (27) "point of production" means (A) for oil … the device through which the oil enters into the facilities of a carrier pipeline…in a condition of pipeline quality…"
- AS 43.55.009 (10) "oil" means (A) crude petroleum oil: and (b) all liquid hydrocarbons that are recovered…by gas processing in a gas processing plant.

North Slope Central Gas Facility

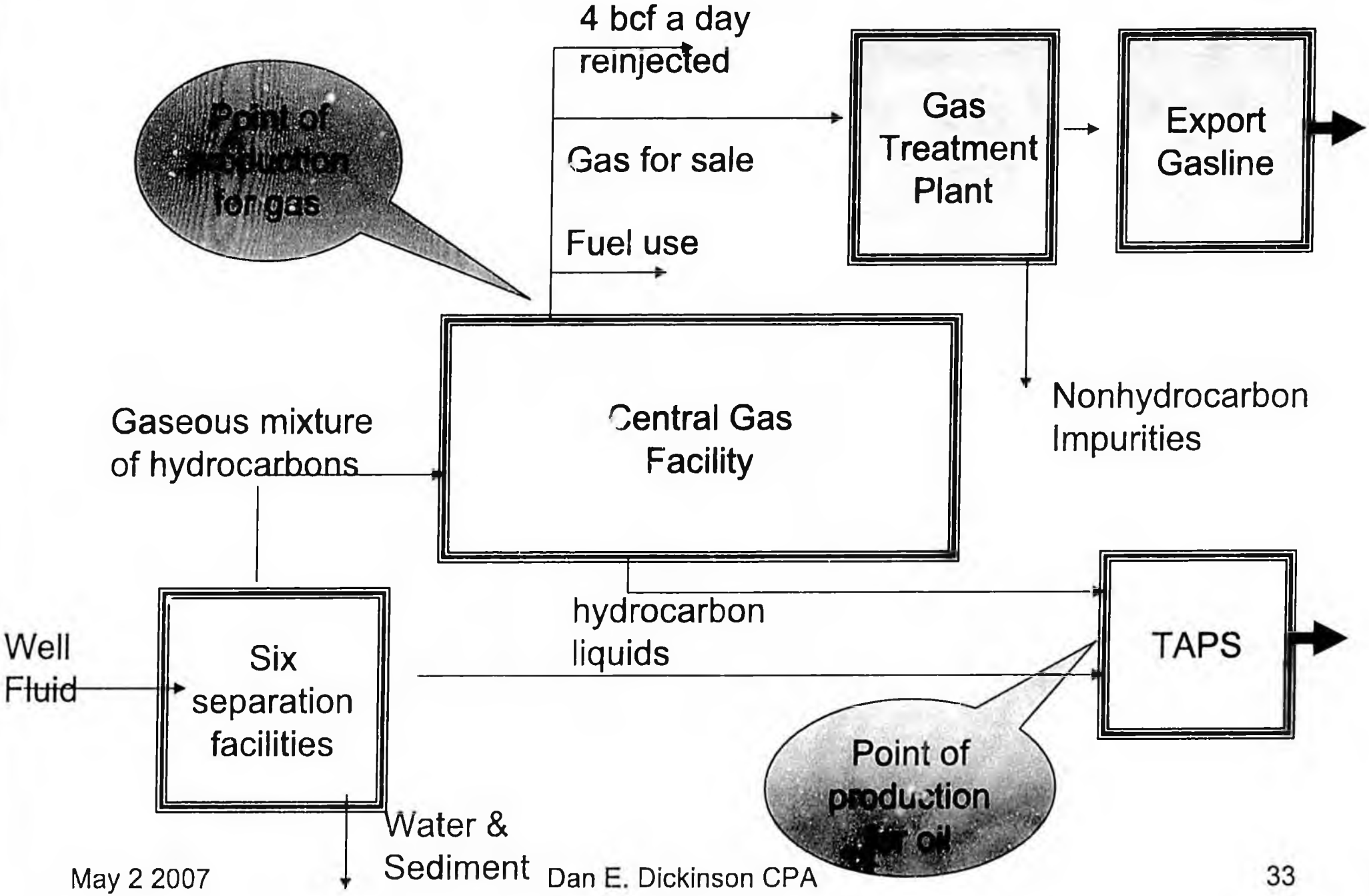
- On the Alaska North Slope the Central Gas Facility is a gas processing plant,

- AS 43.55.020 (e) "… gas used in the operation of a lease or property in the state in drilling for or producing oil or gas or for repressuring…is not considered…as … gas produced from a lease or property."

Answer to the Question:

- If CGF remains a separate plant and sends gas to a Gas Treatment Plant (GTP), gas would be produced as it is metered out of plant. The GTP would be downstream of the point of production for the gas and thus associated operating and capital costs would not qualify as lease expenditures under AS 43.55.165 (a) nor would capital costs qualify for credit treatment under AS 43.55023 (a).

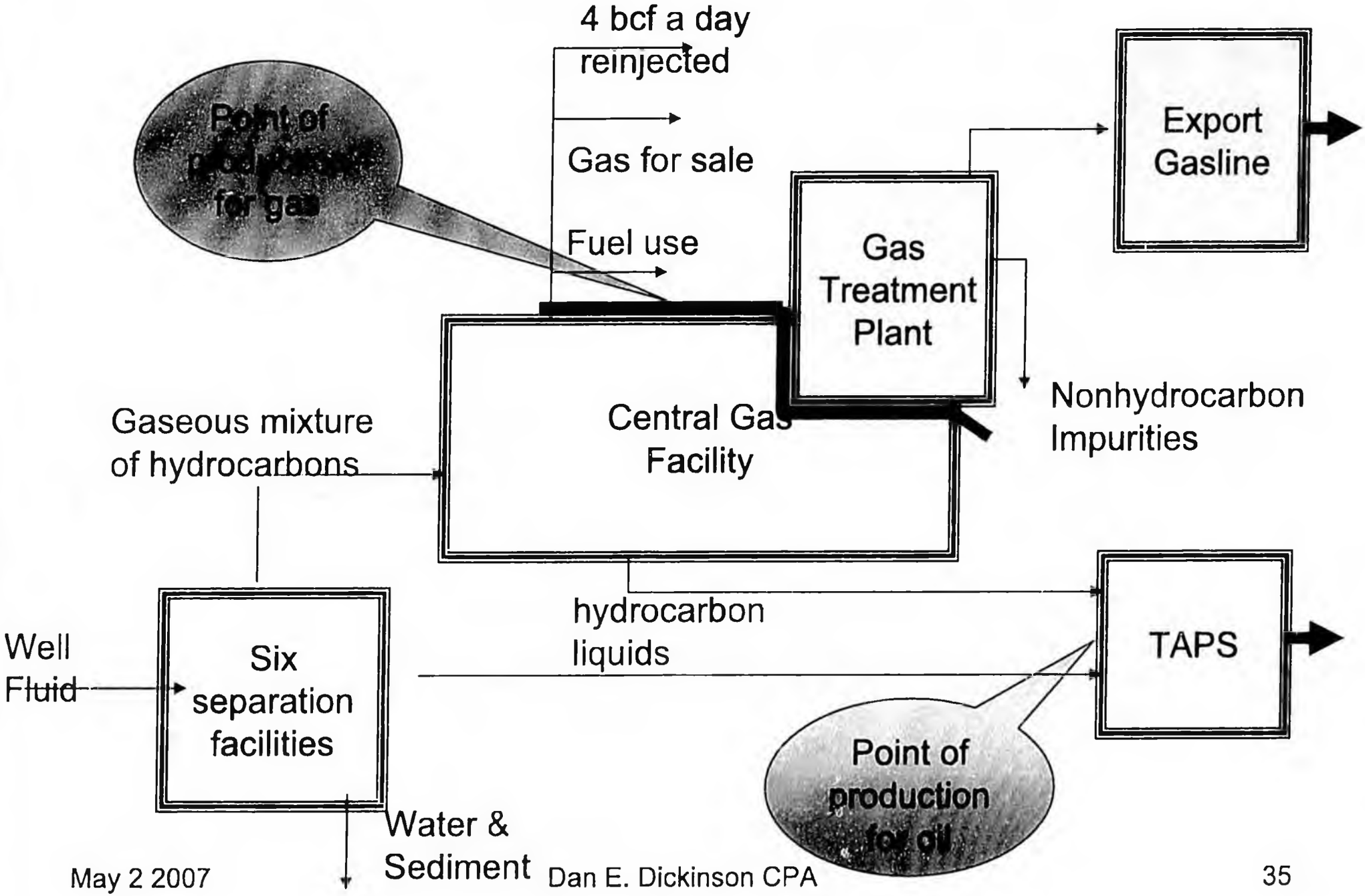
Prudhoe Bay: Point of Production under the PPT with a GTP



Answer to the Question:

- If CGF becomes integrated into a Gas Treatment Plant (GTP) (produced gas is not metered), then the gas would be produced within that integrated facility, at the furthest point upstream of the beginning of gas treatment or the end of gas processing. If the plants are integrated, the risk is that some gas processing will move downstream of the point of production, not that gas treatment will move upstream of the point of production.

Prudhoe Bay: Point of Production under the PPT w/integrated GTP



- We are trying to determine how attractive an investment this pipeline is. Antony Scott, Commercial Analyst, DNR, Oil and Gas, in his April 11, 2007 presentation shows that using the IRR metric this project can have very high rates of return, particularly with a third party line. However we believe he does not include the cost of shippers' firm transportation commitments in his numbers when comparing an independent pipeline with a producer owned pipeline. How might this affect his results?

Firm Transportation

- Shipper makes a Firm Transportation commitment (FT) to pay the capital portion of the tariff whether it uses the pipeline or not.
- It is that financial commitment that underwrites the pipeline:
  - Required by FERC before approving a project
  - Required by lenders before lending money to a project.

Producers' returns as both shippers + pipeline owners

AGIA
The Alaska Gasline Inducement Act

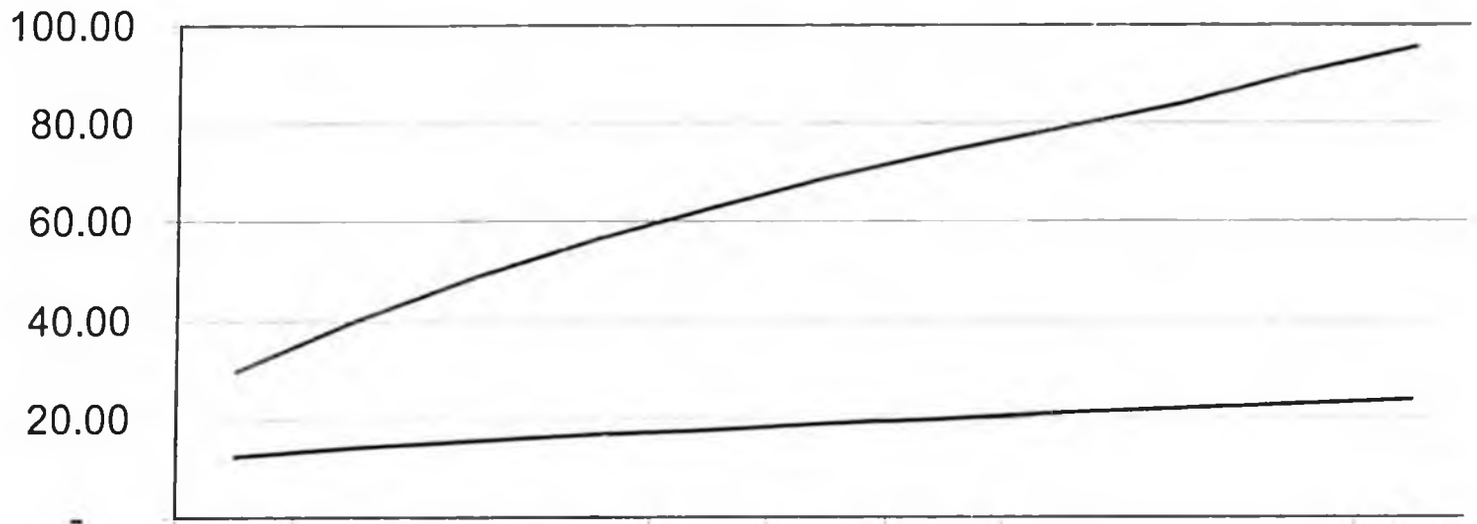
	NPV	IRR	P/I	NPV per BOE
$3.50	3.0	12.6%	1.3	$0.37
$4.00	5.0	14.0%	1.4	$0.60
$4.50	6.9	15.4%	1.6	$0.83
$5.00	8.7	16.7%	1.7	$1.06
$5.50	10.6	17.9%	1.9	$1.28
$6.00	12.4	19.0%	2.0	$1.50
$6.50	14.2	20.1%	2.2	$1.72
$7.00	16.0	21.1%	2.3	$1.93
$7.50	17.7	22.1%	2.5	$2.14
$8.00	19.3	23.0%	2.6	$2.33
$8.50	20.8	23.9%	2.7	$2.51

Producer Upstream Returns
Base case cost = $20.5B

AGIA
The Alaska Gasline Inducement Act

	NPV	IRR	P/I	NPV per BOE
$3.50	4.1	29.8%	3.2	$0.49
$4.00	6.1	39.7%	4.3	$0.74
$4.50	8.1	48.7%	5.3	$0.98
$5.00	10.1	56.3%	6.4	$1.22
$5.50	12.1	62.9%	7.5	$1.46
$6.00	14.0	68.9%	8.5	$1.70
$6.50	16.0	74.2%	9.5	$1.93
$7.00	17.8	79.2%	10.5	$2.15
$7.50	19.6	83.9%	11.5	$2.37
$8.00	21.3	90.4%	12.4	$2.57
$8.50	22.9	95.6%	13.2	$2.76

Calculated IRR at various price levels



	3.5	4.0	4.5	5.0	5.5	6.0	6.5	7.0	7.5	8.0	8.5
— Upstream & Pipeline	12.6	14.0	15.4	16.7	17.9	19.0	20.1	21.1	22.1	23.0	23.9
— Upstream Only	29.8	39.7	48.7	56.3	62.9	68.9	74.2	79.2	83.9	90.4	95.6

Internal Rate of return

	Step One: Model An Owned Project			
	CapCosts	Op Costs	Revenues	Cash Flows
Units:		1000	1000	
Dollars		0.1	5	
Product		100	5000	
Year				
0	(20,000)			(20,000)
1		(100)	5,000	4,900
2		(100)	5,000	4,900
3		(100)	5,000	4,900
4		(100)	5,000	4,900
5		(100)	5,000	4,900
6		(100)	5,000	4,900
7		(100)	5,000	4,900
8		(100)	5,000	4,900
9		(100)	5,000	4,900
10		(100)	5,000	4,900
			IRR:	21%

Internal Rate of Return

	Step Two: Model Capital Component of Tariff			
	Using PAYMENT function			
Units:				
Dollars	Balance	Interest	Payment	Balance
Product		10%		
Year				
0				20,000.00
1	20,000.00	2,000.00	(3,254.91)	18,745.09
2	18,745.09	1,874.51	(3,254.91)	17,364.69
3	17,364.69	1,736.47	(3,254.91)	15,846.25
4	15,846.25	1,584.63	(3,254.91)	14,175.97
5	14,175.97	1,417.60	(3,254.91)	12,338.66
6	12,338.66	1,233.87	(3,254.91)	10,317.62
7	10,317.62	1,031 76	(3,254.91)	8,094.47
8	8,094.47	809.45	(3,254.91)	5,649.01
9	5,649.01	564.90	(3,254.91)	2,959.01
10	2,959.01	295.90	(3,254.91)	0.00

Internal Rate of Return

	Step Three: Model Third Party Line with no FT but with tariff		
	Tariff	Revenues	Cash Flows
Units:			
Dollars			
Product			
Year			
0			
1	(3,354.9)	5,000.0	1,645.1
2	(3,354.9)	5,000.0	1,645.1
3	(3,354.9)	5,000.0	1,645.1
4	(3,354.9)	5,000.0	1,645.1
5	(3,354.9)	5,000.0	1,645.1
6	(3,354.9)	5,000.0	1,645.1
7	(3,354.9)	5,000.0	1,645.1
8	(3,354.9)	5,000.0	1,645.1
9	(3,354.9)	5,000.0	1,645.1
10	(3,354.9)	5,000.0	1,645.1
		IRR:	#NUM!

Internal Rate of Return

	Step Four: Model Third Party Line with some additional capital		
	Tariff	Revenues	Cash Flows
Year			
0			(100.0)
1	(3,354.9)	5,000.0	1,645.1
2	(3,354.9)	5,000.0	1,645.1
3	(3,354.9)	5,000.0	1,645.1
4	(3,354.9)	5,000.0	1,645.1
5	(3,354.9)	5,000.0	1,645.1
6	(3,354.9)	5,000.0	1,645.1
7	(3,354.9)	5,000.0	1,645.1
8	(3,354.9)	5,000.0	1,645.1
9	(3,354.9)	5,000.0	1,645.1
10	(3,354.9)	5,000.0	1,645.1
			1645%

Internal Rate of Return

	Step Five: Model Third Party Line with some more additional capital		
	Tariff	Revenues	Cash Flows
Year			
0			(2,000.0)
1	(3,354.9)	5,000.0	1,645.1
2	(3,354.9)	5,000.0	1,645.1
3	(3,354.9)	5,000.0	1,645.1
4	(3,354.9)	5,000.0	1,645.1
5	(3,354.9)	5,000.0	1,645.1
6	(3,354.9)	5,000.0	1,645.1
7	(3,354.9)	5,000.0	1,645.1
8	(3,354.9)	5,000.0	1,645.1
9	(3,354.9)	5,000.0	1,645.1
10	(3,354.9)	5,000.0	1,645.1
			82%

Internal Rate of Return

	Step Six: Model Third Party Line		
	with yet more additional capital		
	Tariff	Revenues	Cash Flows
Year			
0			(6,750.0)
1	(3,354.9)	5,000.0	1,645.1
2	(3,354.9)	5,000.0	1,645.1
3	(3,354.9)	5,000.0	1,645.1
4	(3,354.9)	5,000.0	1,645.1
5	(3,354.9)	5,000.0	1,645.1
6	(3,354.9)	5,000.0	1,645.1
7	(3,354.9)	5,000.0	1,645.1
8	(3,354.9)	5,000.0	1,645.1
9	(3,354.9)	5,000.0	1,645.1
10	(3,354.9)	5,000.0	1,645.1
	IRR:		21%

FASB 47 Disclosure of Long Term Obligations (1981)

- This statement requires that an enterprise disclose its commitments under unconditional obligations that are associate with suppliers financing arrangements. Such obligations often are in the form of take-or-pay contracts and throughput contracts.

FASB 47 Disclosure of Long Term Obligations (1981)

- Example 2
- 27. C Company has entered into a throughput agreement with a natural gas pipeline providing that C will provide specified quantities of natural gas (representing a portion of capacity) for transportation through the pipeline each period while the debt used to finance the pipeline remains outstanding. The tariff approved by the Federal Energy Regulatory Commission contains two provision, a demand charge and a commodity charge. The demand charge is computed to cover debt service, depreciation, and certain expected expenses.

FASB 47 Disclosure of Long Term Obligations (1981)

- 27. (cont.) The commodity charge is intended to cover other expenses and provide a return on the pipeline company's investment. C Company must pay the demand charge based on the contract quantity regardless of actual quantities shipped, while the commodity charge is applied to actual quantities shipped. Accordingly, the demand charge multiplied by the contracted quantity represents a fixed and determinable amount.

FASB 47 Disclosure of Long Term Obligations (1981)

- 28. C' disclosure might be as follows:
  - C company has signed an agreement providing for the availability of needed transportation capacity through 1990. Under that agreement, the company must make specified minimum payments monthly. The aggregate amounts of such required payments at December 31, 19X1 is as follows (in thousands):

FASB 47 Disclosure of Long Term Obligations (1981)

- 28 (cont).

• 19X2	$	5,000
• 19X3		5,000
• 19X4		5,000
• 19X5		4,000
• 19X6		4,000
• Later years		26,000
• Total		49,000
• Less: Amount representing interest		(9,000)
• Total at present value	$	40,000

FASB 47 Disclosure of Long Term Obligations (1981)

- 28 (cont).
- In addition the company is required to pay additional amount depending on actual quantities shipped under the agreement. The companies total payments under the agreement were (in thousands) $6,000 in 19W9 and $5,000 both in 19X0 and in 19X1.

Contractual Commitments

The following table summarizes the Group's principal contractual obligations at December 31, 2003. Further information on borrowings and capital leases is given in Item 18 — Financial Statements — Note 29 on page F-47 and further information on operating leases is given in Item 18 — Financial Statements — Note 17 on page F-29.

Expected payments by period under contractual obligations and commercial commitments	Payments due by period						
	Total	2004	2005	2006	2007	2008	2009 and thereafter
				($ million)			
Borrowings (a)	20,143	9,366	2,674	2,786	1,299	945	3,073
Finance lease obligations	4,634	127	243	248	240	248	3,528
Operating leases	8,115	1,275	1,066	895	799	728	3,352
Decommissioning liabilities	7,504	86	156	173	154	156	6,779
Environmental liabilities	2,430	465	441	402	276	186	660
Pensions (b)	26,682	633	649	652	659	666	23,423
Other post-employment benefits (c)	11,768	242	252	259	263	264	10,488
Unconditional purchase obligations (d)	67,828	45,491	7,076	3,133	1,888	1,655	8,585

(a) Expected payments exclude interest payments on borrowings.

(b) Represents the expected future contributions to funded pension plans and payments by unfunded pension plans.

(c) Represents the expected future payments for postretirement benefits.

(d) Represents any agreement to purchase goods or services that is enforceable and legally binding and that specifies all significant terms. The amounts shown include arrangements to secure long-term access to supplies of crude oil, natural gas, feedstocks and pipeline systems. In addition, the amounts shown for 2004 include purchase commitments existing at December 31, 2003 entered into principally to meet the Group's short term manufacturing and marketing requirements. The price risk associated with these crude oil, natural gas and power contracts is discussed in Item 11 — Quantitative and Qualitative Disclosures about Market Risk on page 170.

The following table summarizes the nature of the Group's unconditional purchase obligations.

Unconditional purchase obligations payments due by period	Payments due by period						
	Total	2004	2005	2006	2007	2008	2009 and thereafter
				($ million)			
Crude oil and oil products	22,043	19,350	844	452	422	374	601
Natural gas	19,439	13,189	2,575	1,141	489	398	1,647
Chemicals and other refinery feedstocks	10,049	2,277	1,666	753	563	545	4,245
Utilities	11,612	9,622	1,231	289	62	54	354
Transportation	2,814	738	510	368	247	204	750
Use of facilities and services	1,871	315	250	133	105	80	988
Total	67,828	45,491	7,076	3,133	1,888	1,655	8,585

BPs 2003 20(f)

- Unconditional purchase obligations (d)
- (d) Represents any agreement to purchase goods or services that is enforceable and legally binding and that specifies all significant terms. The amounts shown include arrangements to secure long-term access to supplies of crude oil, natural gas feedstocks and pipeline systems.
- Obligations set out for five years, after five years and in total

Why does this matter?

- Moody' Investors Service
- Authors (or "Contacts"):
- Barbara Havlicek, Kevin Stoklosa, Greg Jonas, Laura Levenstein, Pamela Stumpp, Michel Madelain, Trevor Pijper, Wofgang Draak, Waylon Iserhoff, Brian Cahill, Thomas Keller, Takohiro Morita
- The Analysis of Off-Balance Sheet Exposures, A Global Perspective
- July 2004

Moody's Rating Methodology

- Take-Or-Pay Contracts
- Take or pay contracts are another form of purchase commitment typically found in the … energy industry. … Such contracts can be problematic if market conditions and raw material prices change or if the price of the end product drops. Regardless of whether of not the contract becomes problematic, Moody's factors payments under take-or-pay contracts into the analysis of future cash flows and may also adjust the balance sheet if necessary. (Havlicek page 7)

Why does this matter?

- Standard & Poor's
- Authors (and "Analytical Contacts"):
- Solomon B. Samson, Scott Sprinzen, Emmanuel Dubois-Pelerin, Kenneth C. Pfeil
- Corporate Ratings Criteria
- 2006

Standard and Poor's Rating Methodology

- Off balance-sheet financing
  - Analysis of liabilities is not limited to those shown on the company's balance sheet. Off balance-sheet items factored into the leverage analysis include the following:
    - Operating leases
    - Guarantees, debt of joint ventures and unconsolidated subsidiaries
    - Take-or-pay contracts and obligations under throughput and deficiency agreements…
  - (Samson pgs. 28-29)

Standard and Poor's Rating Methodology

- Various methodologies are used to determine the proper adjustment value for each off-balance-sheet item. In some cases, the adjustment is straightforward. For example, the amount of guaranteed debt can simply be added to the guarantor's liabilities. Other adjustments are more complex or less precise. (Samson pg. 29)

Closing Thought:

- E.C. Capen and D.F.Casey The Economics of Creative Financing

  Society of Petroleum Engineers 11664 (1983)

Closing Thought:

- Now and then, someone comes in and announces that he has discovered the business man's equivalent to the Fountain of Youth – a corporate money tree. The person will instruct us that his pet project (PP) need not compete for cash in the budgeting process because he has found a benefactor, Mr. S. Claus, willing to put up the money at no cost save some "small monthly payments" to be worked out later. These payments should come from PP's profits and represent no real drain on the company.

Close of Closing Thought

- To be sure we seldom see requests as blatant as portrayed above, but we nevertheless sense some misunderstandings about how to evaluate projects that have alternatives to outright purchase of goods and equipment. Has the old maxim prohibiting free lunches somehow been set aside with regard to so called creative financing? No, more likely the lunch costs more than normal, but we're not always sure who pays. (Capen & Casey pg. 241)

5/2/07

Contractual Commitments

The following table summarizes the Group's principal contractual obligations at December 31, 2003. Further information on borrowings and capital leases is given in Item 18 — Financial Statements — Note 29 on page F-47 and further information on operating leases is given in Item 18 — Financial Statements — Note 17 on page F-29.

Expected payments by period under contractual obligations and commercial commitments	Payments due by period						
	Total	2004	2005	2006	2007	2008	2009 and thereafter
				($ million)			
Borrowings (a)	20,143	9,366	2,674	2,786	1,299	945	3,073
Finance lease obligations	4,634	127	243	248	240	248	3,528
Operating leases	8,115	1,275	1,066	895	799	728	3,352
Decommissioning liabilities	7,504	86	156	173	154	156	6,779
Environmental liabilities	2,430	465	441	402	276	186	660
Pensions (b)	26,682	633	649	652	659	666	23,423
Other post-employment benefits (c)	11,768	242	252	259	263	264	10,488
Unconditional purchase obligations (d)	67,828	45,491	7,076	3,133	1,888	1,655	8,585

(a) Expected payments exclude interest payments on borrowings.

(b) Represents the expected future contributions to funded pension plans and payments by unfunded pension plans.

(c) Represents the expected future payments for postretirement benefits.

(d) Represents any agreement to purchase goods or services that is enforceable and legally binding and that specifies all significant terms. The amounts shown include arrangements to secure long-term access to supplies of crude oil, natural gas, feedstocks and pipeline systems. In addition, the amounts shown for 2004 include purchase commitments existing at December 31, 2003 entered into principally to meet the Group's short term manufacturing and marketing requirements. The price risk associated with these crude oil, natural gas and power contracts is discussed in Item 11 — Quantitative and Qualitative Disclosures about Market Risk on page 170.

The following table summarizes the nature of the Group's unconditional purchase obligations.

Unconditional purchase obligations payments due by period	Payments due by period						
	Total	2004	2005	2006	2007	2008	2009 and thereafter
				($ million)			
Crude oil and oil products	22,043	19,350	844	452	422	374	601
Natural gas	19,439	13,189	2,575	1,141	489	398	1,647
Chemicals and other refinery feedstocks	10,049	2,277	1,666	753	563	545	4,245
Utilities	11,612	9,622	1,231	289	62	54	354
Transportation	2,814	738	510	365	247	204	750
Use of facilities and services	1,871	315	250	133	105	80	988
Total	67,828	45,491	7,076	3,133	1,888	1,655	8,585

for BP 20(f) annual rpt

CDP_243768

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- Other. At December 31, 2003, we had guarantees of approximately $340 million outstanding for our portion of other joint-venture debt obligations, which have terms of up to 22 years. Included in these outstanding guarantees was $154 million associated with the Polar Lights Company joint venture in Russia. Payment will be required if a joint venture defaults on its debt obligations.

Capital Requirements

For information about our capital expenditures and investments, see "Capital Spending" below.

Our balance sheet debt at December 31, 2003, was $17.8 billion. This reflects debt reductions of approximately $4.8 billion during 2003, including accounting changes that increased balance sheet debt approximately $2.8 billion as a result of the adoption of FIN 46. See Note 2—Changes in Accounting Principles and Note 14—Debt, in the Notes to Consolidated Financial Statements, for additional information.

During 2003, we reduced our commercial paper balance outstanding from $1.5 billion at December 31, 2002, to $ [illegible] million at December 31, 2003. In 2003, we paid off the following notes and debt facilities as they were called or matured and funded the payments with cash from operating activities and proceeds from asset dispositions:

- $250 million 8.49% Notes due 2023, at 104.245 percent;
- $153 million 8.25% Mortgage Bonds due May 15, 2003;
- $150 million 7.92% Notes due in 2023, at 103.96 percent;
- $250 million 7.20% Notes due 2023, at 103.60 percent;
- $100 million 6.65% Notes that matured on March 1, 2003;
- $103 million SRW Cogeneration Limited Partnership note;
- $500 million Floating Rate Notes due April 15, 2003;
- $90 million Tosco Trust 2000-E 8.78% Senior Secured Notes due 2010;
- $215 million Tosco Trust 2000-E 8.58% Senior Secured Notes due 2010;
- $19[illegible] million Arctic Funding, Limited Partnership 6.85% Senior Secured Note due 2011;
- $100 million of floating rate aviation equipment lease obligations having a final maturity in 2004;
- $48[illegible] million of fixed and floating rate ocean vessel lease obligations having final maturities from 2004 to 2005; and
- $1,1[illegible] million of floating rate marketing lease obligations having maturities from 2003 to 2006.

In October and November 2003, we executed certain interest rate swaps that had the effect of converting $1.5 billion of debt from fixed to floating rate. These swaps qualify for hedge accounting under SFAS 133, "Accounting for Derivative Instruments and Hedging Activities."

Also during 2003, we issued $79.5 million of tax-exempt bonds and amortized an additional amount of $20 million.

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Contractual Obligations

The following table summarizes our aggregate contractual fixed and variable obligations as of December 31, 2003:

	Millions of Dollars				
	Payments Due by Period				
At December 31, 2003	Total	Up to 1 Year	1–3 Years	3–5 Years	After 5 Years
Debt obligations*	$ 17,720	1,434	3,110	1,202	11,974
Capital lease obligations	60	6	12	38	4
Total debt	17,780	1,440	3,122	1,240	11 [illegible]
Operating lease obligations	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Purchase obligations**	54,231	[illegible]9,972	4,869	3,915	29,475
Other long-term liabilities***					
Asset retirement obligations	2,685	41	242	364	2,018
Accrued environmental costs	1,119	140	304	138	537
Total	$ 82,338	22,084	9,347	6,216	45,181

*Total debt excluding capital lease obligations. Includes net unamortized premiums and discounts.

**Represents any agreement to purchase goods or services that is enforceable and legally binding and that specifies all significant terms. The majority of the purchase obligations are market-based contracts. Includes: (1) our commercial activities of $23.0 billion, of which $11.3 billion are primarily related to the supply of crude oil to our refineries and the optimization of the supply chain, $5.6 billion primarily related to the supply of unfractionated NGLs to fractionators, optimization of NGL assets, and for resale to customers, $4.4 billion primarily related to natural gas for resale to customers, $1.7 billion of futures, and $217 million related to the purchase side of exchange agreements; (2) $23.3 billion of purchase commitments for products, mostly natural gas and natural gas liquids, from CPChem over the remaining term of 97 years; and (3) purchase commitments for jointly owned fields and facilities where we are the operator, of which some of the obligations will be reimbursed by our co-owners in these properties. Does not include: (1) purchase commitments for jointly owned fields and facilities where we are not the operator; (2) our agreement to purchase up to 104,000 barrels per day of Petrozuata crude oil for a market-based formula price over the term of the Petrozuata joint venture (about 35 years) in the event that Petrozuata is unable to sell the production for higher prices; and (3) an agreement to purchase up to 165,000 barrels per day of Venezuelan Merey, or equivalent, crude oil for a market price over a remaining 16-year term if a variety of conditions are met.

***Does not include: (1) Taxes—the company's consolidated balance sheet reflects liabilities related to income, excise, property, production, payroll and environmental taxes. We anticipate the current liability of $2,676 million for accrued income and other taxes will be paid in the next year. We have other accrued tax liabilities whose resolution may not occur for several years, so it is not possible to determine the exact timing or amount of future payments. Deferred income taxes reflect the net tax effect of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for tax purposes; (2) Pensions—for the 2004 through 2008 time period, we expect to contribute an average of $400 million per year to our qualified and non-qualified pension and postretirement medical plans in the United States and an average of $100 million per year to our non-U.S. plans, which are expected to be in excess of required minimums in many cases. Our required minimum funding in 2004 is expected to be $95 million in the United States and $75 million outside the United States; (3) Severance—we have expected severance payments of $109 million in 2004 and $1 million in 2005; and (4) Interest—we anticipate payments of $1,046 million in 2004, $2,012 million for the period 2005 through 2006, $1,708 million for the period 2007 through 2008, and $8,955 million for the remaining years to total $13,721 million.

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Capital Spending

Capital Expenditures and Investments

	Millions of Dollars			
	2004 Budget	2003	2002	2001
E&P				
United States—Alaska	$ 656	870	706	965
United States—Lower 48	763	841	499	189
International	3,939	3,090	2,071	1,162
	5,3[illegible]	4,[illegible]02	3,276	2,316
Midstream	10	10	5	—
R&M				
United States	1,019	844	676	421
International	246	319	164	3
	1,265	1,1[illegible]	840	42[illegible]
Chemicals	—	—	60	[illegible]
Emerging Businesses	62	164	172	—
Corporate and Other*	167	188	93	66
	$ 6,[illegible]	6,160	4,388	[illegible]
United States	$ 2,[illegible]	2,[illegible]	2,043	1,[illegible]
International	4,[illegible]	3,676	2,[illegible]	1,167
	$ 6,[illegible]	6,169	4,[illegible]	3,0[illegible]
Discontinued operations	$ —	234	97	19

* Excludes discontinued operations.

Our capital spending for continuing operations for the three-year period ending December 31, 2003, totaled $13.6 billion. Spending was primarily focused on the growth of our E&P business, with 77 percent of total spending for continuing operations in this segment. The capital programs of DEFS, our gas gathering, processing and marketing joint-venture company, and CPChem, our chemicals joint-venture company, are intended to be self-funding, and are not reflected in our amounts above.

Including about $[illegible] million in capitalized interest and $400 million that will be funded by minority interests in the Bayu-Undan gas export project, our Board has approved $6.9 billion for capital projects and investments for continuing operations in 2004, a 12 percent increase over our 2003 capital spending of $6.2 billion. We plan to direct 78 percent of our 2004 capital budget to E&P and 18 percent to R&M. The remaining budget will be allocated toward emerging businesses, mostly power generation, and general corporate purposes, with a majority related to global integration of systems. Thirty-eight percent of the budget is targeted for projects in the United States.

E&P

Capital spending for continuing operations for E&P during the three-year period ending December 31, 2003, totaled $10.5 billion. The expenditures over the three-year period supported several key exploration and development projects including:

- National Petroleum Reserve-Alaska (NPR-A) and satellite field prospects on Alaska's North Slope;

from ConocoPhillips 2003 10(K)

CDP_243769

from ExxonMobil 2003 10(K)

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Index to Financial Statements

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

company benefit plans and programs and to reduce the number of shares outstanding. Shares outstanding were reduced from 6,700 million at the end of 2002 to 6,568 million at the end of 2003. Purchases were made in both the open market and through negotiated transactions. Purchases may be increased, decreased or discontinued at any time without prior notice.

2002

Cash used in financing activities was $11.4 billion, down $3.7 billion, reflecting lower debt reductions. Dividend payments on common shares increased to $0.92 per share from $0.91 per share and totaled $6.2 billion, a payout of 54 percent. Total consolidated short-term and long-term debt was comparable at $10.7 billion. Shareholders' equity increased by $1.4 billion to $74.6 billion.

During 2002, Exxon Mobil Corporation purchased 127 million shares of its common stock for the treasury at a gross cost of $4.8 billion. These purchases were to offset shares issued in conjunction with company benefit plans and programs and to reduce the number of shares outstanding. Shares outstanding were reduced from 6,809 million at the end of 2001 to 6,700 million at the end of 2002. Purchases were made in both the open market and through negotiated transactions.

Commitments

Set forth below is information about the corporation's commitments outstanding at December 31, 2003. It provides data for easy reference from the consolidated balance sheet and from individual notes to the consolidated financial statements.

		Payments Due by Period				
Commitments	Note Reference Number	2004	2005-2008	2009 and Beyond	2003 Total Amount	2002 Total Amount
		(millions of dollars)				
Long-term debt [1]	15	$ —	$ 877	$3,879	$4,756	$6,655
– Due in one year [2]		1,903	—	—	1,903	884
Asset retirement obligations [3]	10	125	461	2,854	3,440	3,454
Pension obligations [4]	18	1,180	1,720	4,937	7,837	9,385
Operating leases [5]	11	1,299	2,730	2,160	6,189	6,945
Unconditional purchase obligations [6]	17	520	1,703	2,563	4,786	3,649
Take-or-pay obligations [7]		833	1,874	1,340	4,047	3,475
Firm capital commitments [8]		4,251	2,173	595	7,019	8,449

This table excludes commodity purchase obligations for which an active, highly-liquid market exists and which are expected to be re-sold shortly after purchase. Inclusion of such amounts would not be meaningful in assessing liquidity and cash flow, since such purchases will be offset in the same periods by cash received from sales.

Notes:

(1) Includes capitalized lease obligations of $370 million. Long-term debt amounts exclude the corporation's share of equity company debt, which is included in the calculation of return on average capital employed as shown on page 27.

(2) The amount due in one year is included in notes and loans payable of $4,789 million (note 7).

(3) The discounted present value of upstream asset retirement obligations, primarily asset removal costs at the completion of field life.

(4) The amount by which accumulated benefit obligations (ABO) exceeded the fair value of fund assets for certain U.S. and non-U.S. plans at year end (note 18 on page 65). For funded pension plans, this difference was $3.0 billion at December 31, 2003 (U.S. $0.5 billion, non-U.S. $2.5 billion). For unfunded plans, this was the ABO amount of $4.9 billion (U.S. $1.0 billion, non-U.S. $3.9 billion). The payments by period include expected contributions to funded pension plans in 2004 and estimated benefit payments for unfunded plans in all years.

(5) Minimum commitments for operating leases, shown on an undiscounted basis, cover drilling equipment, tankers, service stations and other properties.

(6) Unconditional purchase obligations (UPOs) are those long-term commitments that are noncancelable and that third parties have used to secure financing for the facilities that will provide the contracted goods or services. The undiscounted obligations of $4,786 million mainly pertain to pipeline throughput agreements and include $1,887 million of obligations to equity companies. The present value of the total commitments, excluding imputed interest of $1,543 million, was $3,243 million.

(7) Take-or-pay obligations are noncancelable, long-term commitments for goods and services other than unconditional purchase obligations. The undiscounted obligations of $4,047 million mainly pertain to transportation, refining and natural gas purchases and include $622 million of obligations to equity companies. The present value of the total commitments, excluding imputed interest of $663 million, totaled $3,384 million.

(8) Firm commitments related to capital projects, shown on an undiscounted basis, totaled approximately $7.0 billion at the end of 2003, compared with $8.4 billion at the end of 2002. These commitments were predominantly associated with upstream projects outside the U.S., of which the largest single commitment outstanding at the end of 2003 was $1.6 billion associated with the development of crude oil and natural gas resources in Malaysia. The corporation expects to fund the majority of these commitments through internal cash flow.

Guarantees

	Equity Company Obligations	Other Third Party Obligations	Total
		(millions of dollars)	
Guarantees of excise taxes/customs duties under reciprocal arrangements	$ —	$ 983	$ 983
Other guarantees	1,872	424	2,296
Total	$ 1,872	$ 1,407	$3,279

The corporation and certain of its consolidated subsidiaries were contingently liable at December 31, 2003 for $3,279 million, primarily relating to guarantees for notes, loans and performance under contracts (note 17). This included $983 million representing guarantees of non-U.S. excise taxes and customs duties of other companies, entered into as a normal business practice, under reciprocal arrangements. Also included in this amount were guarantees by consolidated affiliates of $1,872 million, representing ExxonMobil's share of obligations of

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Alaska Gasline
PORT AUTHORITY

House Finance Committee

May 3, 2007

AGPA Project Description

Alaska Gasline Port Authority

Gas Conditioning Plant in Prudhoe Bay

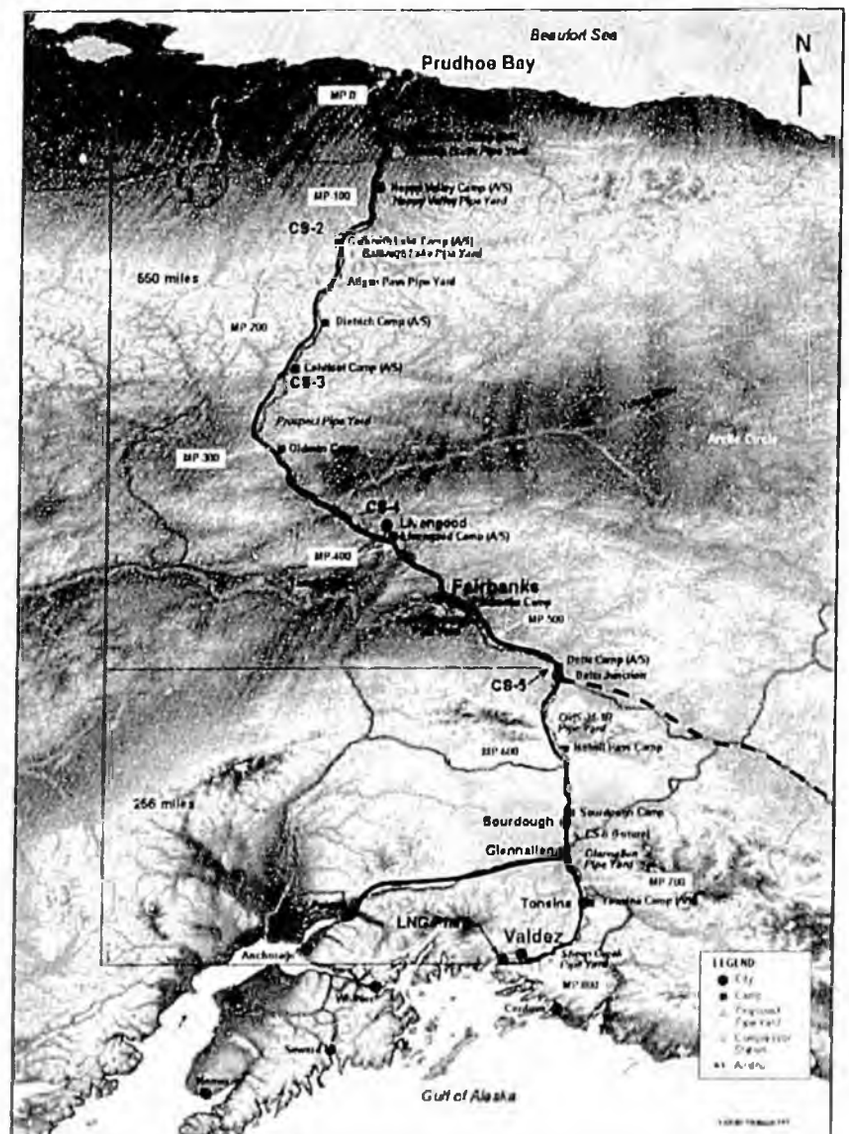
- removes impurities
- compresses and chills the gas to pipeline specifications

Pipeline from Prudhoe Bay to Valdez

- parallel to TAPS (max. capacity: 6 Bcfd)
- pre-build to Delta Junction for later tie-in for the Alaska/Canada Highway Project
- tie-in at Glennallen for a spur line to Alaska South Central natural gas grid

LNG Facility in Valdez

- integrated LNG liquefaction and LPG extraction facilities
- includes storage and vessel loading facilities



Phased Project = Better Cost Overrun Risk Management

Alaska Gasline Port Authority

- 800 mile pipeline is 100% adjacent to TAPS, 100% in Alaska
- Infrastructure in place for entire line – roads, bridges, camp pads, etc.
- LNG project: lower overall cost overrun risk:
  - liquefaction facilities utilize proven technology and well-tested design, resulting in a relatively low level of uncertainty in cost estimate
  - low level of cost uncertainty for LNG marine transportation and regasification
  - pipeline component has the highest capital cost uncertainty – for LNG project the pipeline is only a portion of overall cost to market
- Phase approach with LNG project proceeding first: 2/3 less cost = 2/3 less risk
- Phase 1 can proceed with only one producer- rather than all three

Project Status

Alaska Gasline Port Authority

1. Project Route Permitted

2. The 12 Senior Permits Acquired
   - Yukon Pacific Corporation
   - $100 million expended
   - Right-of-way
   - Project FEIS
   - LNG terminal permit

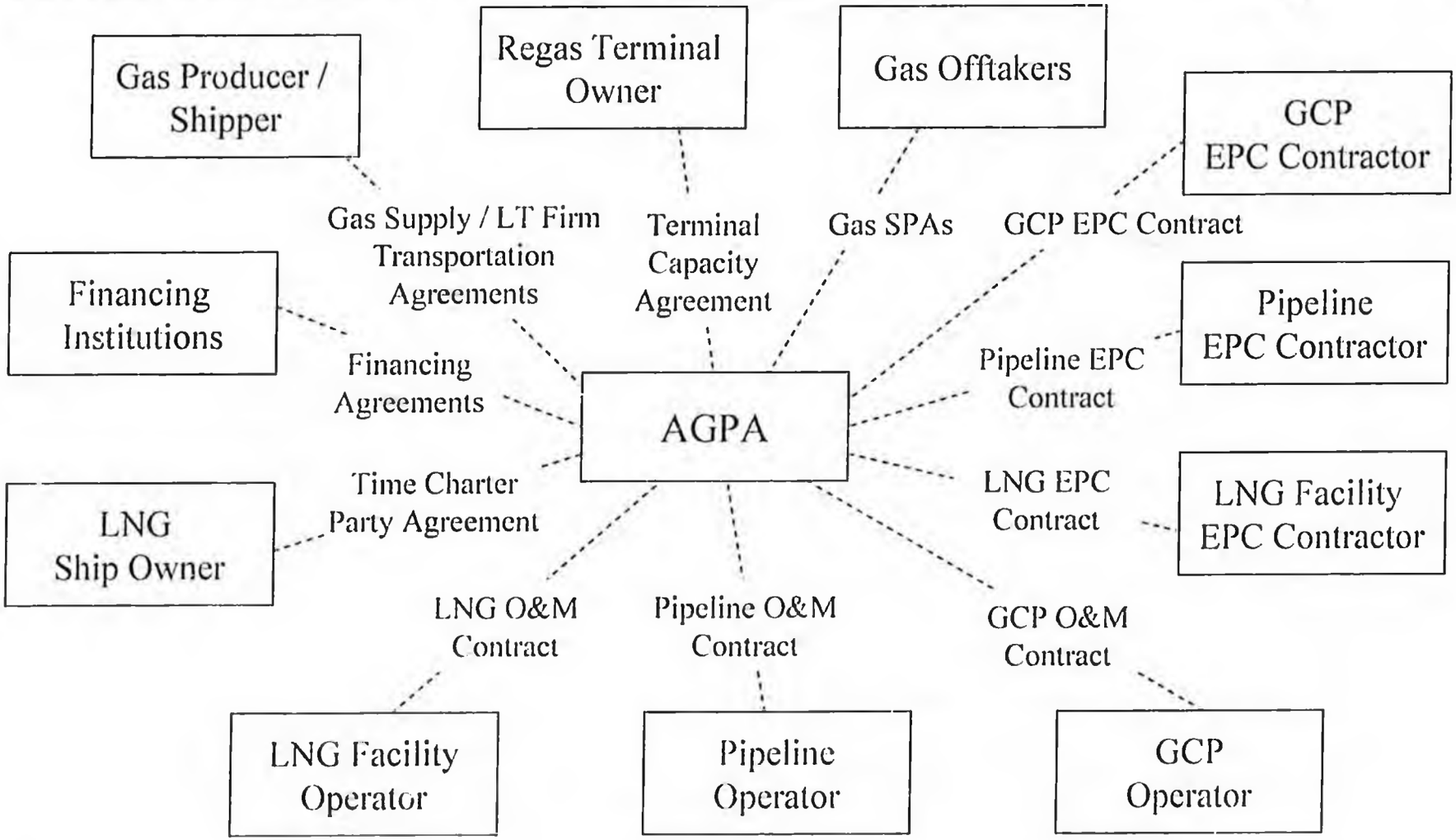
3. Bechtel Cost Estimates
   - Complete & Updated

4. Marine Transportation / Jones Act
   - MOU with the largest LNG shipping company in the world – Mitsui OSK Lines

5. Access to Multiple Markets
   - West Coast receiving terminal under construction
   - West Coast Alternatives
   - Hawaii
   - Pacific Rim

6. Anticipated Financing
   - 80% debt (Federal loan guarantee available)
   - 20% private funding

Indicative AGPA Project Structure



- Industry leaders will be involved in all components of AGPA's project

AGIA is Good for Alaska

Alaska Gasline Port Authority

Alaska Gasline Inducement Act (AGIA) Process:

- Open, transparent and competitive
- Identifies clear evaluation criteria
- Inducements to project applicants in exchange for specific commitments
- Empowers selected applicant to build successful consortium, leading to open season
- Separates the mid-stream from the upstream
- Brings in additional interested parties to develop Alaska's gas resources

AGIA Suggested Amendments

- Additional gas reserves needed? Budget and timeline for exploration program
- Analysis of making liquids available in Alaska for value added processing
- Current project cost estimate required with application

AGIA benefits towards advancing gas pipeline

- Rolled in rates – good for Alaska's future
- Allows for independently owned infrastructure
- Follows successful model used in other countries who also use rolled in rates and independently owned pipelines.
- $500 million skin in the game – sends very positive message about A' ska's desire to commercialize Alaska's gas
- Supports lowest tariff

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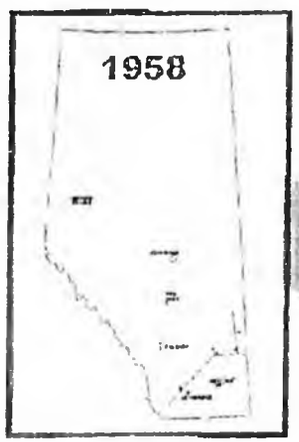
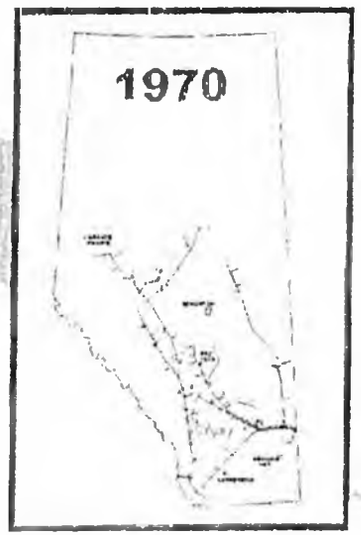
5/4/07

TransCanada - Proven Basin Developer





Regulatory Structure
- **Independent pipeline model**
- **Rolled-in tolls**

TransCanada

Legal Notice

The following presentation contains forward-looking statements concerning BG Group's operations, financial performance, strategy, outlook and growth opportunities. Words such as "believes", "expects", "anticipates", "intends" or similar expressions are intended to identify such forward-looking statements.

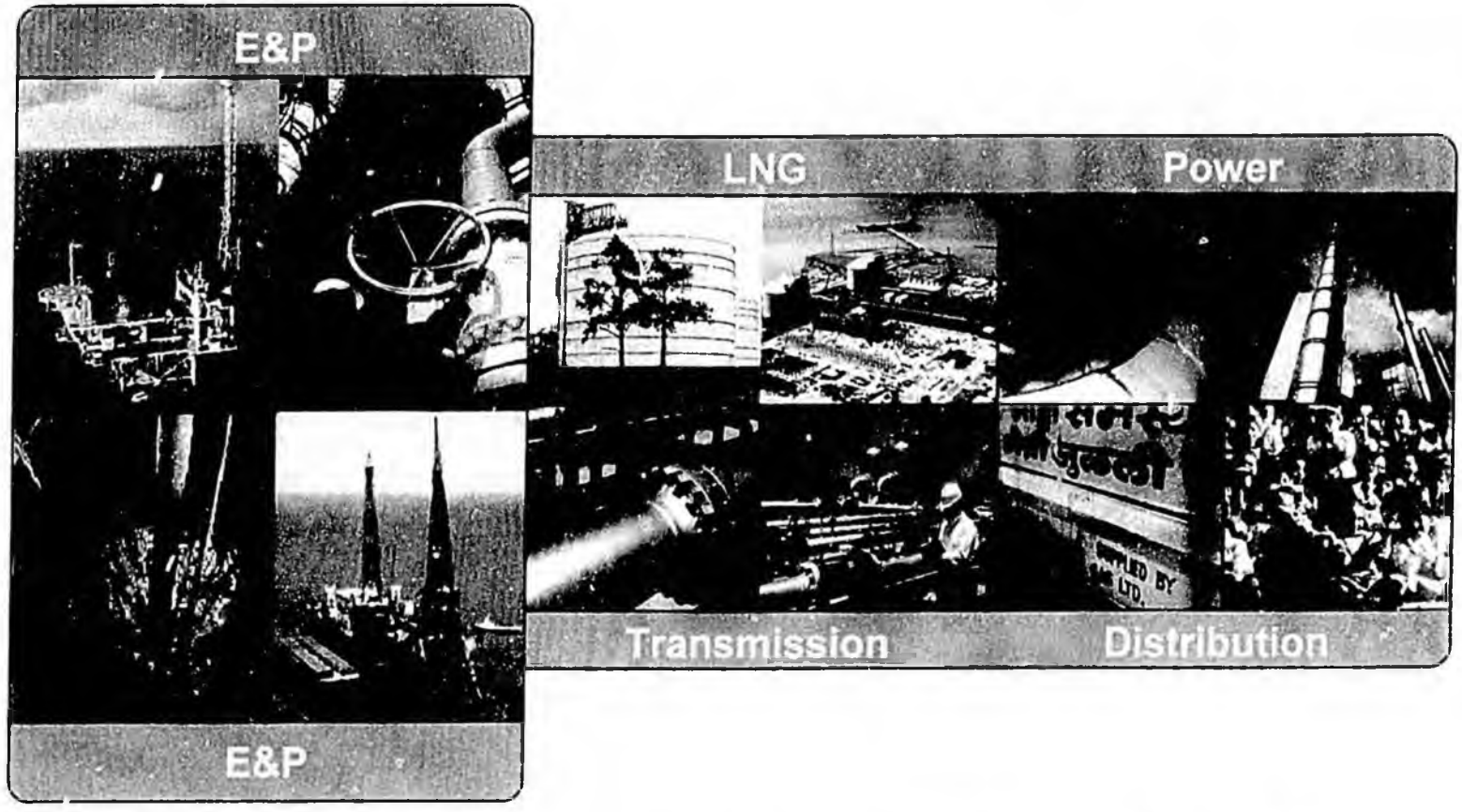
By their nature, forward-looking statements involve uncertainty because they depend on, and relate to, future circumstances and events, not all of which are within our control. Although BG Group believes that the expectations reflected in such forward-looking statements are reasonable, no assurance can be given that such expectations will prove to have been correct. Accordingly, results could differ materially from those set out in such forward-looking statements for a number of reasons, including but not limited to, changes in economic, market and competitive conditions; regulatory changes; governmental actions; fluctuations in commodity prices and exchange rates; supply and demand for oil and gas; the risks inherent in project implementation and delivery, and exploration and production activities; the inability or failure of co-venturers to meet contractual and/or funding obligations; natural disasters and adverse weather conditions; and war, sabotage and acts of terrorism. For a more detailed analysis of the factors that may affect our business, the results of our operations and our financial performance, we urge you to look at certain 'Risk Factors' included in BG Group's Annual Report and Accounts 2006. BG Group undertakes no obligation to update any forward-looking statements.

No part of this presentation constitutes or shall be taken to constitute an invitation or inducement to underwrite, subscribe for or otherwise acquire, or dispose of any ordinary shares, ADRs or other investment in BG Group plc or any other entity, nor does it advise any person to do any of the foregoing and this presentation must not be relied upon in any way in connection with any investment decision.

BG Group snapshot

- A world leader in natural gas
- A FTSE 20 company, listed on London and New York Stock Exchanges
- Market capitalisation over $49 billion
- Production circa 70% gas; 30% oil
- Employs approx 4,766 staff; 64% outside UK, at year end 06

Business model

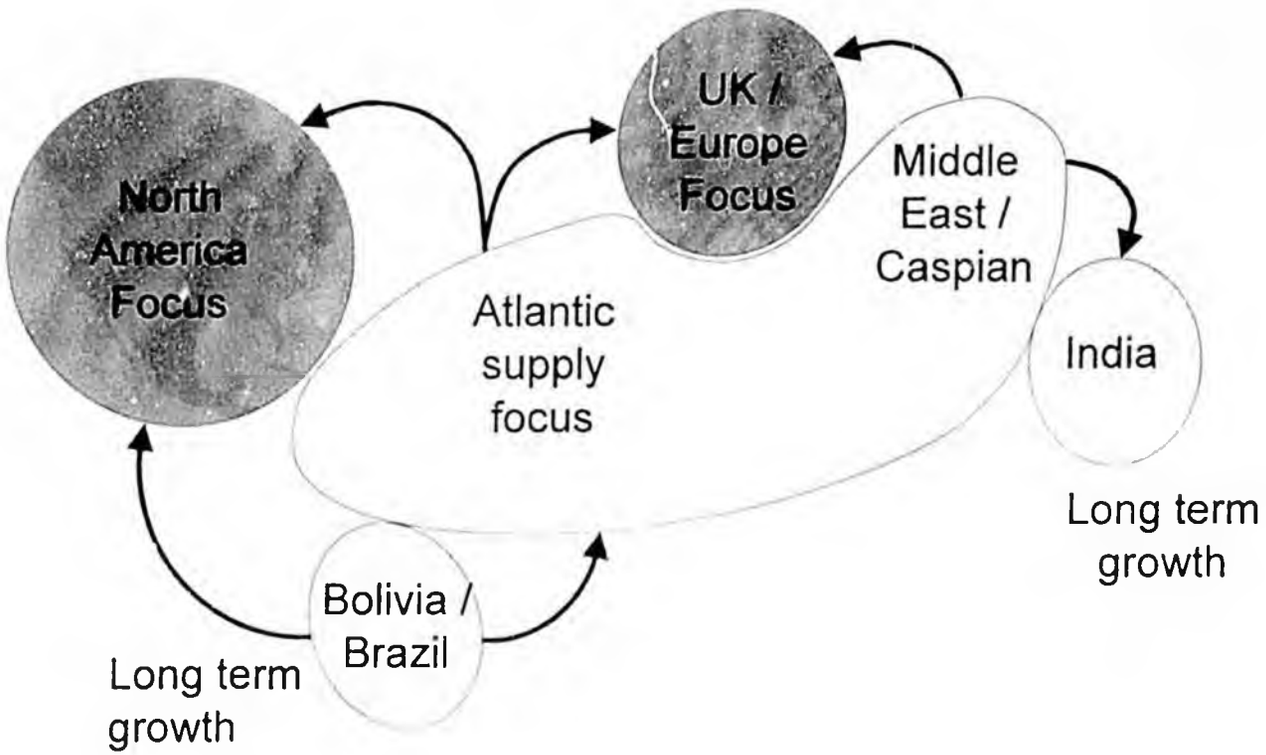


Resources → Enabling → Markets

Countries of current operation

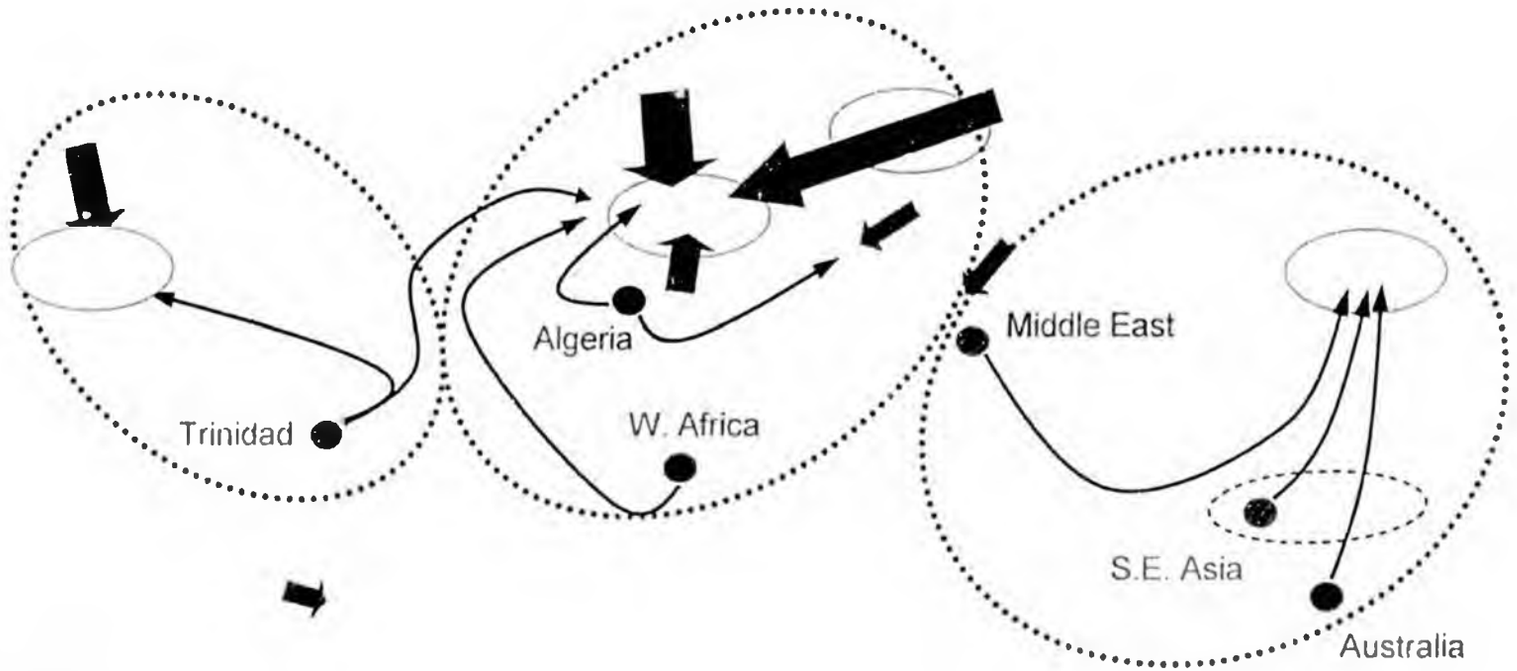
Active in over 25 countries

Gas market focus



Developed Market Developing Market Supplies

Global gas trade – the recent past



Markets

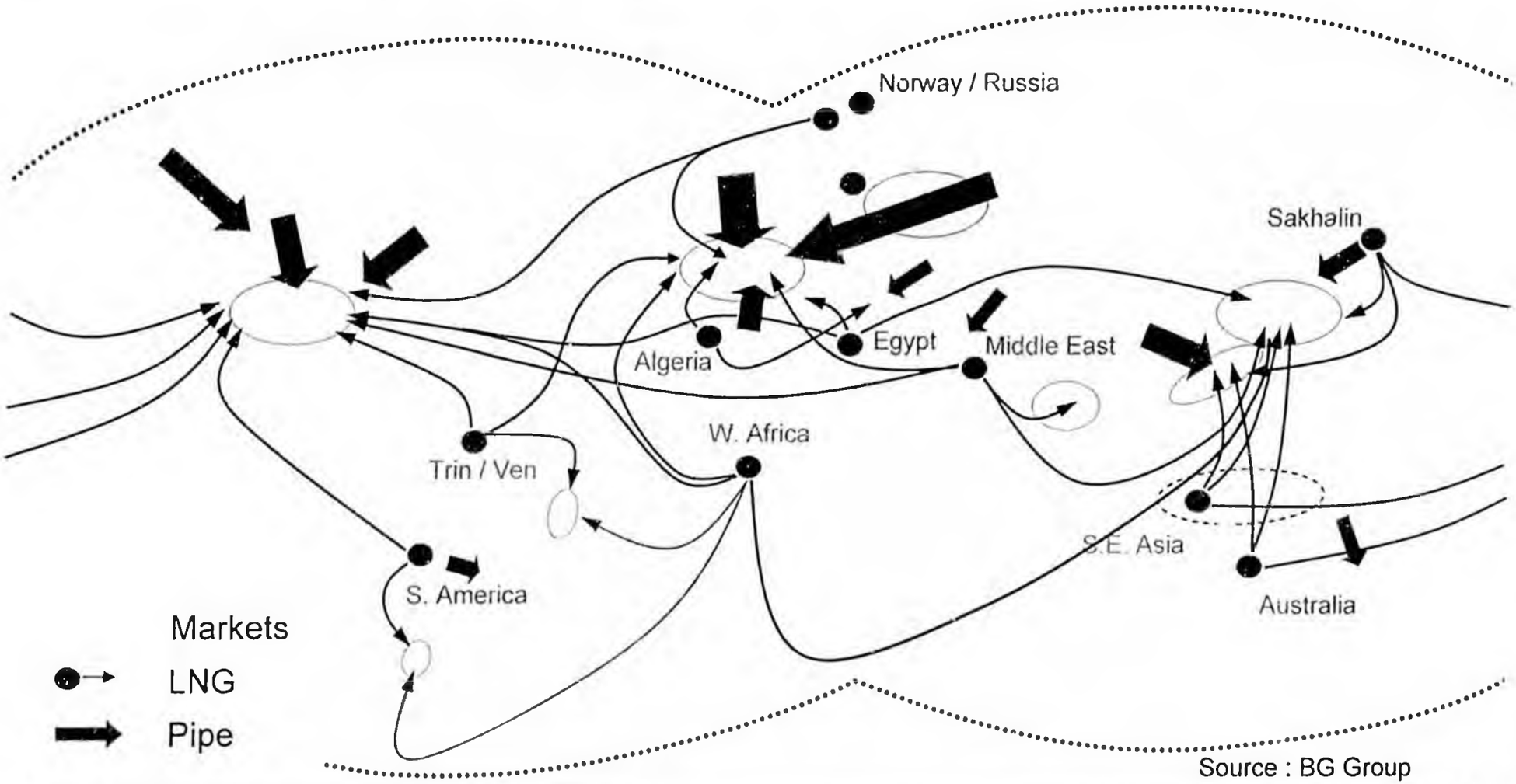
LNG

Pipe

Source : BG Group

Industry evolution: from three main trade regions…

Global gas trade – gradually evolving



Source : BG Group

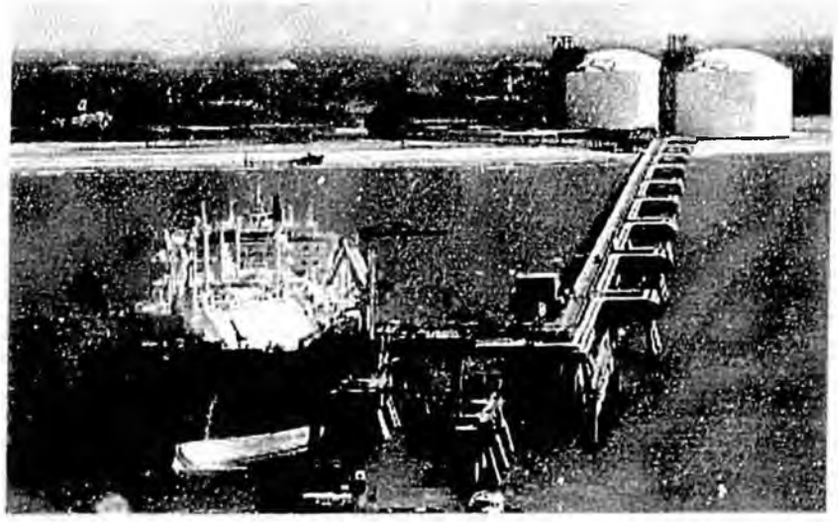
... to a globalising gas industry

BG LNG supply projects

ATLANTIC LNG
COMPANY OF TRINIDAD AND TOBAGO

- Train 1: 3.1 mtpa – 1999 (BG 26.0%)
- Train 2/3: 6.6 mtpa – 2002 (BG 32.5%)
- Train 4: 5.2 mtpa – 2005 (BG 28.9%)
- BG initiated project and was instrumental in Phillips design
- Single train start-up

Liquefied Natural Gas
Egyptian LNG

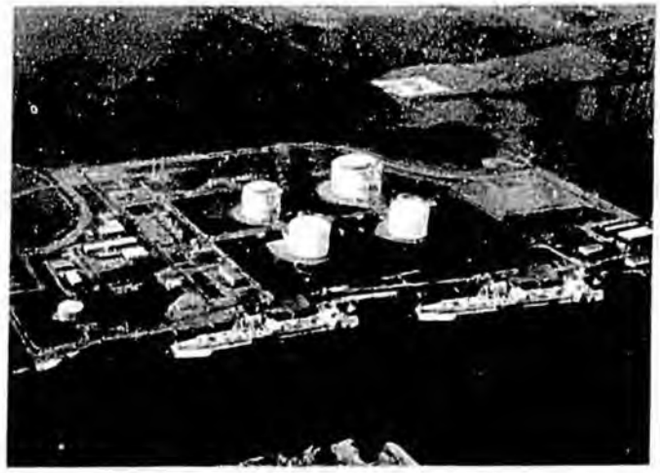


- Train 1: 3.6 mtpa – 2005 (BG 35.5%)
- Train 2: 3.6 mtpa – 2005 (BG 38.0%)
- Egypt's largest project financing to date
- Unique project commercial structure
- Utilized lessons learnt from ALNG

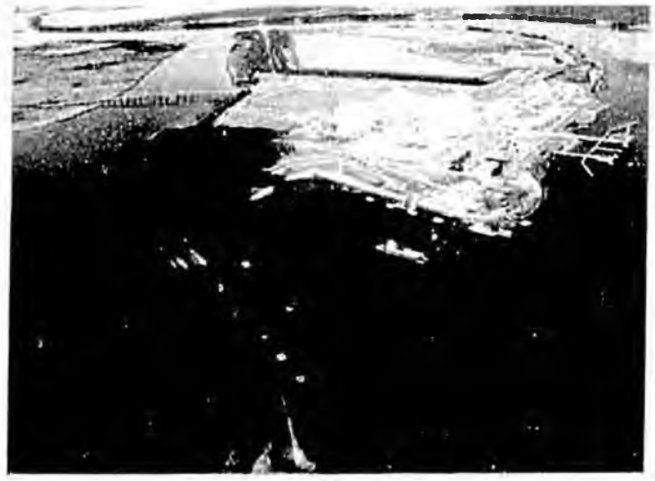
Atlantic LNG – total export capacity of 15 mtpa in just 7 years

US market summary

- Lake Charles import terminal
- Phase I expansion Q4 2005
  - 1.2 bcf/d sustainable send out
  - 1.5 bcf/d peak send out
  - 9.1 bcf total storage
- Phase II expansion Q2 2006
  - 1.8 bcf/d sustainable send out
  - 2.1 bcf/d peak send out
- Elba Island import terminal
  - 0.45 bcf/d sustainable send out
  - 0.67 bcf/d peak send out
  - 4.0 bcf storage capacity
  - 1.17 bcf/d firm send out & 8.2 bcf storage after second expansion



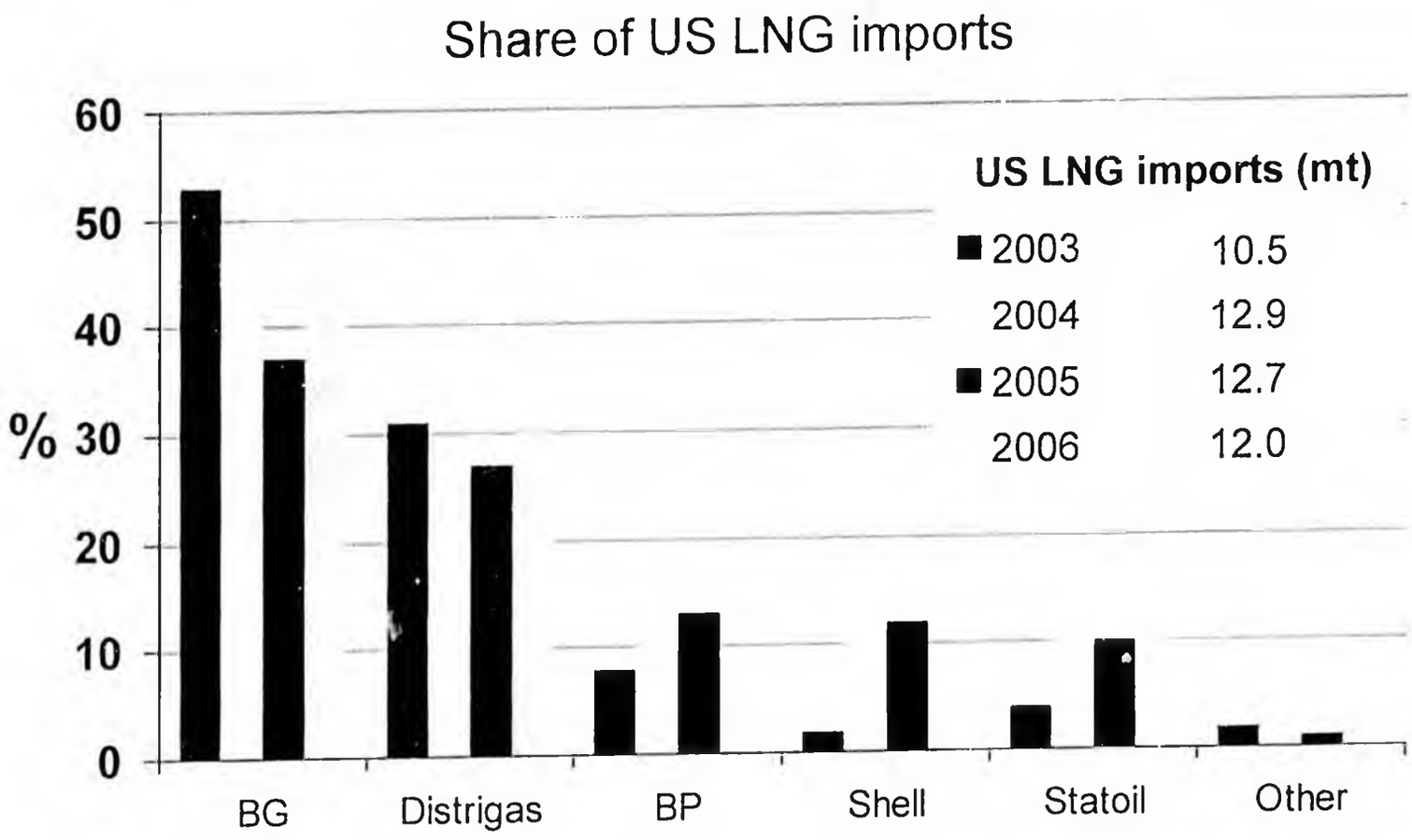
Lake Charles



Elba Island

Capacity in two of the four existing US onshore terminals

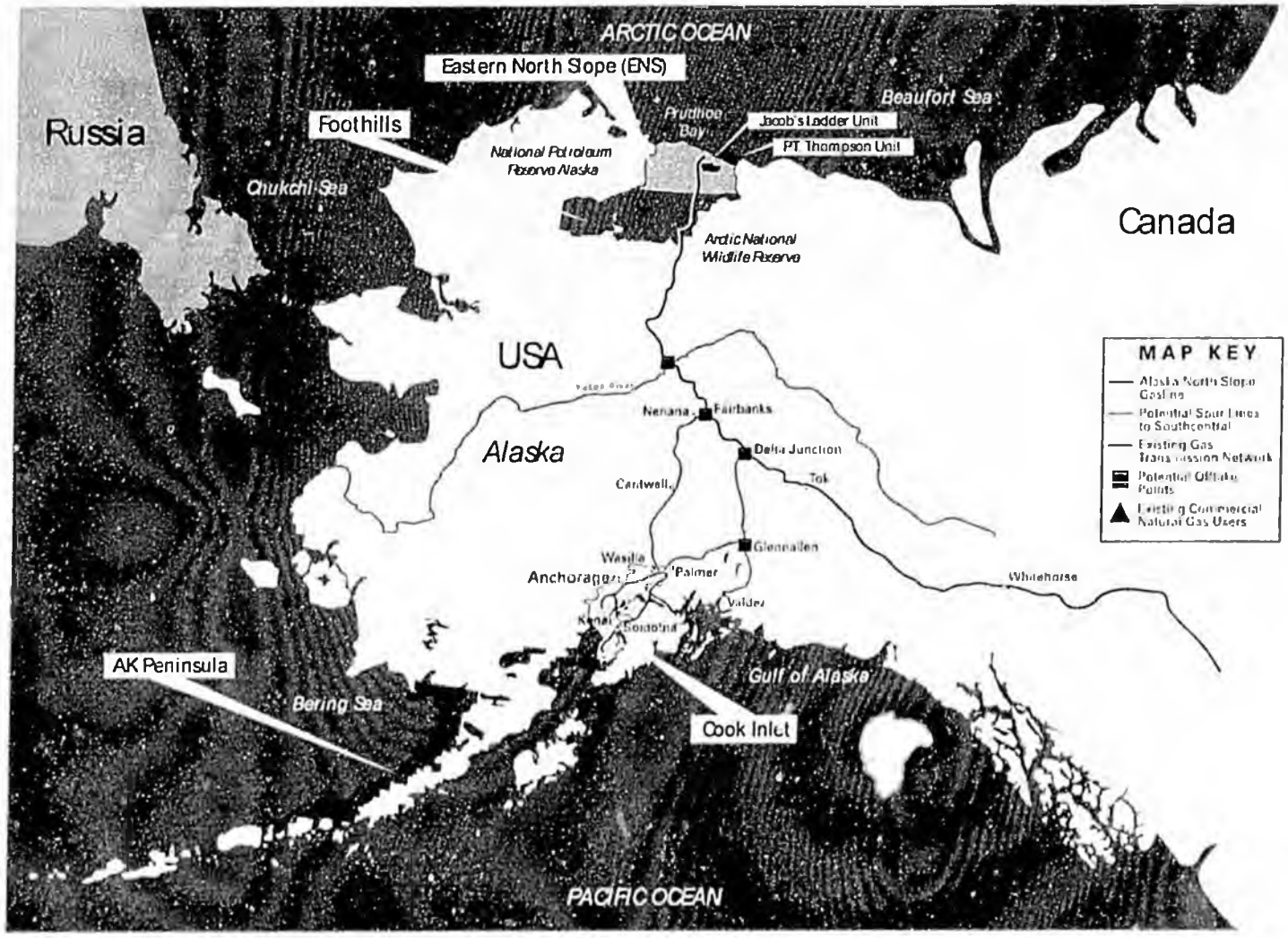
LNG imports – 2003 to present



Source : DOE

BG – the largest US LNG importer in 2003, 2004, 2005 and 2006

Alaska E&P



2.1 million acres in the Foothills of ANS and .2 million in the ENS

Alaska Gasline Inducements Act

- BG is investing in Alaska
  - Exploring along North Slope and ENS
- BG supports AGIA
  - The process is fair, open and inclusive
  - BG supports the mandatory provisions on access and rates
  - Will encourage new explorers to invest in Alaska
- AGIA provides:
  - Opportunities for input by all interested parties
  - Several opportunities for legislators to provide input:
    - Initial legislation
    - When pipeline applications are submitted
    - Legislative review of the winning application

AGIA will encourage development

Alaska Gasline Inducements Act

- AGIA addresses BG's concerns by:
  - Providing a level playing field for all participants
  - Providing certainty that when we discover gas, we will have access to pipeline capacity
  - Providing a mechanism to ensure just and reasonable rates
- AGIA creates competition to build the pipeline and possibly an LNG export facility
- AGIA spells out what is required of any applicant
- Clearly identifies the State's "must haves"
- BG's "must haves" are:
  - Regulated pipeline
  - Open access provisions in the tariff
  - Just and reasonable rates

AGIA will encourage development

Key messages

- AGIA is good for Alaska and for the natural gas industry
- AGIA will encourage the continued development of Alaska's untapped natural gas reserves
- AGIA's purpose:
  - "...to encourage expedited construction of a natural gas pipeline that

  (1) Facilitates commercialization of North Slope gas resources of the state;

  (2) promotes exploration and development of oil and gas resources on the North Slope;

  (3) maximizes benefits to the people of the state from the development of oil and gas resources in the state; and

  (4) encourages oil and gas lessees and other persons in the state to commit natural gas from the North Slope to a gas pipeline system for transportation to markets in this state or elsewhere."


BG North America

minutes 5/4/07

The Palin-Parnell Administration presents

AGIA

The Alaska Gasline Inducement Act

Alaska Gasline Project from Lenders' Perspective
Presentation to House Finance
5/2/2007

The Lenders' Perspective

AGIA
The Alaska Gasline Inducement Act

Lenders consider 5 Cs:

- **Capacity**
  - The debt repayment capability of the pipeline project.
- **Collateral**
  - The secondary source of debt repayment.
- **Character / Credit**
  - Project sponsors (the active equity investors) who are experienced in the pipeline industry and have solid credit history.
- **Commitment**
  - Financial and non-financial commitments from sponsors indicating their incentives to the success of the pipeline project.
- **Conditions**
  - Future market, regulatory, economic and environmental conditions that could impact the viability of the project.

Financing Perspective

AGIA
The Alaska Gasline Inducement Act

- The critical items for a greenfield natural gas export pipeline from Alaska include:
  - Firm long term commitments to ship natural gas, at a price, quantity, and term sufficient to service and repay the necessary debt financing.
  - Equity funding, typically of 20%-30% of the project's forecast capital structure. One or more equity sponsors with the project development, management, and operations skills necessary to undertake this project.
  - Division of cost overrun risks among parties which have the financial strength, and appropriate skills and incentives to manage and bear this risk.
  - FERC, NEB, and other regulatory approvals

- Each of these critical elements is magnified due to the extraordinary size of the proposed project.

- Federal loan guarantees will be helpful in maximizing the quantity of debt and limiting the cost of pipeline debt financing, (and the delivered cost of pipeline gas to consumers), but are not a substitute for any of the key elements listed above.

Firm Transportation (FT) Commitments

AGIA
The Alaska Gasline Inducement Act

- Firm long term commitments to ship natural gas, at a price, quantity, and term sufficient to service and repay the necessary debt financing are normally necessary for a successful financing.
  - Demonstrate (via open season) the need for the project from regulatory perspective
  - Provide equity investors with necessary assurance of earning an acceptable return
  - Critical to give lenders assurance of debt repayment (in absence of federal guarantee)

- Bulk of the shipper commitments will very likely come from the parties which own the gas supply.
  - Only the producers have sufficient economic interest to make firm transportation commitment
  - Given the high level of capital expenditure necessary for the project, the exact terms of the shipping commitments are of great importance to suppliers in determining the acceptability of their economics
  - Shipper commitments are normally needed 1) prior to closing on debt financing and pipeline construction, and 2) prior to equity making large "at risk" commitments – including large pre-approval development outlays

Equity Commitments

AGIA
The Alaska Gasline Inducement Act

- Equity Commitments are a pre-condition to debt financing and federal guarantees

- Typical greenfield FERC regulated pipeline project is funded with 20%-30% base equity.
  - Exact level is dependent upon project economics and reserves, but some minimum needed to establish sponsor credibility as owner

- Ability to attract equity sponsors rests upon ability to:
  - attract sufficient firm and binding transportation commitments
  - share development cost risks with other interested parties
  - share cost overrun risks with shippers
  - provide a clear regulatory path to approval

Cost Overruns

AGIA
The Alaska Gasline Inducement Act

- Mitigating cost overruns is a key financing concern

- Substantial increases in cost of large capital projects have occurred in recent years, across many industries globally.
  - Complex causes, including higher commodity prices and skilled labor shortages
  - Extreme cost overruns have occurred for mega-projects in the nearby Alberta oil sands

- Because of market conditions, and the project size, there is a limited ability to shift cost overrun risk to contractors and suppliers.

- The magnitude of cost overrun risk, and the modest equity returns typically associated with pipeline equity, will likely drive some need for sharing of this risk between equity investors and shippers
  - Shippers, in turn, will need more protection against potentially very large cost overruns than would be provided in a typical "cost of service" arrangement

Department of Energy Loan Guarantees

AGIA
The Alaska Gasline Inducement Act

- The Alaska Natural Gas Pipeline Act of 2004 gave the U.S. Department of Energy the ability to issue up to US$18 billion in loan guarantees in support of the Alaska natural gas pipeline project.

- Key loan guarantee provisions in Alaska Natural Gas Pipeline Act of 2004 are extremely favorable:
  - Maximum guaranteed debt would be the lesser of US$18 billion (indexed to inflation) or 80% of total capital costs, including interest during construction
  - Owners of Canadian portion of pipeline also eligible
  - Term of 30 years
  - Unusual credit support language indicating that no "*contractual commitment or other form of credit support of the sponsors (other than equity contribution commitments and completion guarantees), or … throughput or other guarantee from prospective shippers greater than such guarantees as shall be required by the project owners*" will be required for loan guarantee

- Favorable terms of legislation may be limited by practicalities of Department of Energy implementation:
  - DoE has been slow to implement the loan guarantee provisions of the Energy Policy Act of 2005
  - DoE solicited public feedback in May 2005 to assist in future rulemaking on pipeline loan guarantees, but has yet to issue any further guidelines or draft regulations

Conclusions

AGIA
The Alaska Gasline Inducement Act

- AGIA has some helpful elements
  - Up to $500 million of risk sharing capital during the project development phase, the most risky stage of the pipeline project
  - The Resource Inducement section encourages FT commitments
  - A requirement that an application shall describe the means for preventing or managing cost overruns for the proposed project

- A pipeline will not be built without ' nders' debt financing

- The financing of the pipeline project needs to be supported by firm transportation commitments, a robust federal guarantee, or a combination of both.

- Finally, there is a lot of what ifs and unknowns with this project, but there is nothing in AGIA which would preclude project financing.

minutes 5/4/07

TESTIMONY OF JOHN K.NORMAN, CHAIR AOGCC
HOUSE FINANCE COMMITTTEE
HB 177
MAY 4, 2007

This afternoon I'll discuss the AOGCC's role in North Slope gas sales and give you a status report.

Most knowledgeable Alaskans know the significance of 35 TCF of natural gas. However, very few people realize that hundreds of millions of barrels of oil and condensate could be lost if gas offtake is not correctly managed.

Oil is Alaska's bird in the hand and gas is our bird in the bush. The AOGCC is responsible for setting the gas offtake allowables from the North Slope oil fields to ensure that we do not harm our bird in the hand while aspiring to grasp our bird in the bush.

In general, maintaining reservoir pressure enhances oil recovery, but producing gas depletes reservoir pressure. Therefore, gas reserves in most fields are usually sold only after most of the oil has been produced. Until then, the gas that is produced with the oil is used to promote increased liquid production in various ways.

For example, gas might be reinjected into the reservoir to provide the energy needed to get the liquid hydrocarbons to the surface, or the gas might be used for enhanced oil recovery operations.

Both of those are happening right now at Prudhoe Bay and other North Slope fields.

Therefore, North Slope gas sales are going to involve trade-offs between oil and gas recovery. It's not practical to get every drop of oil out of the ground before starting gas sales, and the AOGCC

certainly does not take that position. We do however need to ensure that the trade-offs that inevitably will occur result in greater ultimate recovery of both gas and oil

It is important to understand that Prudhoe Bay does have a existing gas offtake allowable. It is 2.7 BCF per day and it was set in 1977.

The AOGCC usually waits for an application from the operator to modify pool rules including offtake rates. However, in 2005 we recognized the following:

First, that serious discussions were taking place concerning major North Slope gas sales

Second, that the 2.7 BCF per day gas offtake allowable for Prudhoe Bay was set in 1977, when the field first began to produce; and, although that offtake rate was based on the best available information at the time, we now have 30 years and 11 billion barrels of production and production-related data to help determine a better number

Third, most of the publicly discussed pipeline options could require more than 2.7 BCF per day offtake from Prudhoe Bay

Forth, performing the necessary studies to determine an appropriate current offtake rate would take time, and

Fifth, the AOGCC did NOT want to be the cause of any project delays.

Therefore, to acquire the most current information, BP and the other Prudhoe Bay working interest owners agreed to provide the AOGCC staff and consultants access to their simulators including the underlying engineering, geologic, and geophysical information. They voluntarily set up a data room in BP's Anchorage offices,

equipped with computers and software allowing review of the simulator results.

It is important to note that the data and information provided to us falls within the standards of AS 31.05.035(d) and 20 AAC 25.537(b) governing confidentiality of information.

In simple terms, the data that has been made available to us is not something we were otherwise entitled to. It belonged solely to the Prudhoe Bay working interest owners. We needed it to perform our study, and the most efficient way for us to get access to it was to agree to keep it confidential.

Our most recent study began in January 2006, and was completed in late 2006. In the course of that study, BP and its partners were cooperative and provided us all that we needed.

On February 28, 2007, we published a summary report. That report is available on the AOGCC website (www.aogcc.alaska.gov); and a copy is in your packet.

As soon as we announced that we had completed our study, everyone wanted to know the magic number, but it's not that easy.

First, it's a multi-variable equation. The right offtake volume will depend on when sales start, how aggressively the oil has been produced in the meantime, and what mitigating steps are in place and planned. And second, there are legal restrictions on what results of the study we can share and how we share them.

As soon as we receive an application or otherwise have enough information to make a meaningful determination, we will convene public hearings and make as much information available as is needed and legally allowed to support any change in the assigned natural gas offtake allowable.

It is our intent to complete our evaluations, hold hearings and make our final rulings on gas offtake allowables for both Prudhoe Bay and Pt Thomson well in time for the "open season" process.

As of now, here's what we can say:

(1) The later gas sales begin, the smaller will be the oil losses.

(2) The lower the offtake rate, the smaller will be the oil losses.

(3) The more the oil production is accelerated before gas sales start, the smaller will be the oil losses.

(4) The more that is done to mitigate detrimental effects of gas sales, the smaller will be the oil losses.

(5) Oil loss is more sensitive to the acceleration of oil production and the mitigating steps than it is to start-up timing or offtake rate.

(6) Depending on the life of the North Slope infrastructure, delaying gas offtake too long, could result in decreased gas recovery.

By the time a pipeline project is ready, selling gas from Prudhoe Bay can very likely proceed at a higher offtake rate than the current 2.7 BCF per day, provided BP and its partners continue working: (1) to accelerate oil production (for example: aggressive infield drilling and operational vigilance to minimize production interruptions) and (2) to mitigate for gas losses (gas cap water injection and using CO2 for EOR, for example).

We are confident, that unless a substantial delay occurs (which could make our analysis stale and require additional analytical work), we will be adequately prepared to make a timely determination of the correct Prudhoe Bay gas offtake allowable rate when an application does come before us.

Now, I would like to talk about Pt Thomson, where we can't make such a confident statement.

A year ago the AOGCC, and Exxon and its partners agreed upon a similar process for studying the allowable gas offtake from Pt Thomson. The AOGCC contracted reservoir evaluation consultants to assist its technical staff in performing the Pt Thomson study. Exxon and its partners agreed to give AOGCC staff and consultants access to a data room in Exxon's Houston offices. It was agreed that the data room would include reservoir engineering, geologic and simulation information and would be equipped with computers and software allowing review of the simulator results. The study was supposed to begin before September 2006 and last up to six months. Exxon and its partners indicated that they planned to apply to the Commission in late 2006 or early 2007 for Pool Rules and a gas offtake allowable rate for Pt Thomson.

Unfortunately we were not able to follow that time line. Exxon had delays in preparing the data room and information. The process was finally slated to begin late last year, about the same time that the DNR found Exxon and its partners to be in default on their leases. We attended one meeting where Exxon presented a small portion of the information we would need, but since then the study has been on hold pending resolution of legal issues.

Without a thorough study, it will be very difficult for the AOGCC to have sufficient information to make a gas offtake ruling on Pt Thomson. So that one remains a wild card – in many ways.

In summary:

(1) There are hundreds of millions of barrels of oil and condensate at risk if Alaska doesn't manage natural gas offtake properly.

(2) The AOGCC is charged with setting gas offtake allowables that will prevent loss of the State's valuable hydrocarbon resources.

(3) The AOGCC intends to perform its function so that we will not delay the project, i.e., before an open season.

(4) We've done the technical work to prepare us to address Prudhoe Bay's offtake without causing that delay.

(5) A lot remains to be done for Pt Thomson; so delay is possible there.

Thank you and I would be happy to take your questions.

BIOGRAPHICAL INFORMATION

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State of Alaska
Oil & Gas Conservation Commission
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Anchorage, AK 99501
Alaska Bar Association Member #6911041

Telephone: (907) 793-1221
Facsimile: (907) 276-7542
Email: John_Norman@admin.state.ak.us

Current Position: Commissioner and Chairman, State of Alaska Oil & Gas Conservation Commission (2004-present)

Other Positions Held: Founding Partner and Shareholder, Hartig Rhodes Hoge & Lekisch, P.C. (1971-2004); Assistant Attorney General, State of Alaska, Department of Law, Natural Resources Section (1969-1971); Exploration Representative, Skelly Oil Company, Texas/Alaska (1967-1968); 1st Lt., United States Army, Germany (1964-1966).

Member: Greater Anchorage Area Board of Health (1973-1975); State Division of Lands Advisory Committee (1976-1977); Federal Bureau of Land Management Advisory Council (1982-1985); President, Common Sense for Alaska, Inc. (1981-1982); Vice President, Anchorage Chamber of Commerce (1983-1985); Chairman, Commonwealth North, Hartig Research Fellowship Trust (1981-2006); Board of Directors, Resource Development Council (1988-2004); Trustee, Iditarod Trail Race Foundation (1976-present); U.S. Department of Commerce, Alaska District Export Council (1992-present); American Institute of Professional Geologists (2003-present); Outstanding Lawyers of America (2003-present); The Best Lawyers in America (2004-present); Alaska Bar Association (Chairman, Natural Resource Law Committee (1977-79), Fee Arbitration Panel (1977-1981), Environmental/Natural Resource Law Section (1980-present), Discipline Hearing Committee (1983-1987); American Bar Association (Member, Environment, Energy and Resources Section; State Chairman, Committee on Environmental Quality, Young Lawyers Section, 1971-1973); Official Alaska Representative and Vice Chairman, Interstate Oil and Gas Compact Commission (2004-2006) (Chairman, Legal & Regulatory Affairs Committee, (2006-present).

Education: University of Missouri (J.D.; A.B. (Geology)).

Admitted to Bar: Alaska; Missouri; U.S. District Court, District of Alaska; U.S. Court of Appeals, Ninth Circuit; U.S. Supreme Court.

Published Works: "Section Line Dedications for Construction of Highways," Alaska Law Journal (Feb. 1970); "Production, Conservation and Utilization of Natural Gas in Alaska," Natural Resources Lawyer (Nov. 1970); "Alaska's D-2 Lands," Alaska Mineral Development Institute Paper No. 5, Rocky Mountain Mineral Law Foundation (Aug. 1978); "Legal Considerations When Entering the Alaska Energy Market," IBC Global Conferences (Sept. 2002); Alaska Oil & Gas Law Reporter, Rocky Mountain Mineral Law Newsletter (1984-2004).

Reported Cases: *Swindel v. Kelly*, 499 P.2d 291 (Alaska 1972); *Zamarello v. Yale*, 514 P.2d 228 (Alaska 1973); *Thomas v. Bailey*, 595 P.2d 1 (Alaska 1979).

CONFIDENTIALITY AGREEMENT GOVERNING THE SHARING OF INFORMATION DURING THE POINT THOMSON UNIT RESERVOIR STUDY PROCESS

1. The State of Alaska and the Point Thomson Unit Working Interest Owners ("Owners") are working to develop stranded gas resources on the Alaska North Slope, including gas resources in the Thomson Sand and the Pre-Mississippian Carbonate reservoirs (collectively, "TSR") within the Point Thomson Unit.

2. In anticipation of that development, the Alaska Oil and Gas Conservation Commission and the Owners have agreed to "Principles Governing Commission Access to Point Thomson Unit Reservoir Study Process" ("Principles"). The Principles refer to two processes: (a) the study process ("Study"), during which AOGCC staff or consultants will be allowed to monitor reservoir studies conducted by the Owners, and (b) the subsequent decision making process ("Proceedings") for determining allowable offtake from the TSR. The Principles establish confidentiality provisions relating to data to which AOGCC staff or consultants may have access during the Study process.

3. The Principles provide the opportunity for Commission staff and consultants to have access during reasonable working hours to a Data Room equipped with computers and software that will allow review, analysis, model visualizations, and report preparation with respect to TSR reservoir simulations and related studies. Accordingly, Commission staff and consultants will have access to data inputs and outputs and underlying engineering, geologic, and geophysical information, including petrophysical data, rock and fluid properties, and operating assumptions for the simulations (altogether, "Data Room Information"). Entry into the Data Room by Commission staff and consultants is subject to the signing of this Confidentiality Agreement ("Agreement") between Exxon Mobil Corporation ("EM") and the undersigned Commission staff or consultant.

4. Paragraph 3 of the Principles provides that

"Commission staff and consultants may take and retain notes during their review of Data Room Information. In addition, Commission staff and consultants may obtain copies in electronic form and remove from the Data Room the following categories of Data Room Information without additional permission by the Owners or Operator:

(a) simulation predictions that are generated from simulation runs conducted during the Study, including
   (i) projected yearly oil, condensate, gas, NGL, produced water, and source water production and injection volumes for the TSR;
   (ii) projected composition of gas produced, sold, re-injected or used by year;
   (iii) predicted average pool reservoir pressures by calendar year, starting at initial conditions;
(b) major assumptions used in simulations such as
   (i) offsite disposition assumptions for production volumes for the TSR by year; and
   (ii) fuel usage assumptions."

The undersigned agrees to the above and that a log shall be kept of any document copied: identifying the copied document and the date the copy was made. The log shall also identify who made the copy and who received the copy if different. If Commission staff or consultants seek to copy and remove other Data Room Information, they agree to make a written request to EM under the terms of Paragraph 3 of the Principles.

5. The undersigned

(a) certifies that he or she is a member of the Commission staff or consultant authorized by the Commission to participate in accessing Data Room Information;

(b) certifies that he or she has read the Principles and agrees to act in compliance with the terms and conditions of the Principles.

6. The undersigned agrees to keep all Data Room Information, including Commission and consultant work product that divulges Data Room Information, strictly secret and confidential in the same manner and to the same extent the Commission agreed such Data Room Information will be treated as confidential under paragraph 4 of the Principles, including an agreement not to release Data Room Information except to AOGCC Commissioners, AOGCC staff, and AOGCC consultants working on the TSR gas offtake analyses and to take precautions that are reasonably necessary to preserve the secrecy and confidentiality of such information using at least the standard of care he or she normally uses in protecting the Commission's or his or her own confidential information. These confidentiality provisions do not apply to Data Room Information that is the same as information that has been otherwise provided without a claim of confidentiality, independently obtained without a confidentiality obligation, or obtained subject to different confidentiality requirements.

7. The undersigned agrees that the unauthorized release of confidential Data Room Information subject to this Agreement may adversely affect the proprietary interests of the Owners. In recognition of these interests, the parties agree that the Owners shall be entitled to seek injunctive relief without a showing of irreparable harm or damages.

8. The release of confidential Data Room Information does not make further releases permissible, and any failure to assert rights under this Agreement shall not be deemed a waiver of any rights under this Agreement.

9. This Agreement shall be interpreted and governed in accordance with the laws of the State of Alaska.

10. This Agreement shall be interpreted consistently with the Principles, which are incorporated into and adopted by this Agreement. In the event of any conflict between the provisions of this Agreement and the Principles, the Principles shall control.

11. This Agreement shall terminate December 31, 2016, provided however that if in the course of Proceedings any information whose contents are identical to that of certain Data Room Information becomes publicly available, that Data Room Information will no longer be subject to the confidentiality provisions of this Agreement. The expiration of the agreement does not affect whether documents entitled to confidentiality remain confidential.

IN WITNESS WHEREOF, the parties have executed this Confidentiality Agreement as of the dates beside their respective signatures

AOGCC EMPLOYEE OR CONSULTANT

Signature
Name: Steve Davies
Title: Sr. Petroleum Geologist
Date: 11.14.06

EXXON MOBIL CORPORATION

By:
Name: RICHARD OLD
Title: AK PRODUCTION MGR
Date: 5-11-06

PRINCIPLES GOVERNING COMMISSION ACCESS TO POINT THOMSON UNIT RESERVOIR STUDY PROCESS

Principles Applicable to the Study Process

1. Paragraphs 2 through 6, below, apply to the study process developed and carried out by the Point Thomson Unit working interest owners ("Owners") and Point Thomson Unit Operator ("Operator") for the purpose of analyzing reservoir development of the Thomson Sand and the Pre-Mississippian Carbonate reservoirs (collectively, "TSR") in the Point Thomson Unit.

2. Without cost to the Commission or its consultants, the Operator shall provide Commission staff and consultants access during reasonable working hours to a Data Room at Operator's Houston, Texas offices equipped with computers and software that will allow review, analysis, model visualizations, and report preparation with respect to TSR reservoir simulations and related studies. Accordingly, Commission staff and consultants shall be given access to data inputs and outputs and underlying engineering, geologic, and geophysical information, including petrophysical data, rock and fluid properties, operating assumptions for the simulations, and other information and assumptions related to TSR development (altogether, "Data Room Information"). The Operator may condition Commission staff's and consultants' entry into the Data Room on their execution and provision to the Operator of the attached confidentiality agreement and on their signing in on a log. Subject to available resources and without cost to

the Commission or its consultants, the Operator and Owners shall honor all reasonable requests by Commission staff to simulate additional cases beyond those initiated by the Owners or Operator.

3. Commission staff and consultants may take and retain notes during their review of Data Room Information. In addition, Commission staff and consultants may obtain copies in electronic form and remove from the Data Room the following categories of Data Room Information without additional permission by the Owners or Operator:

(a) simulation predictions that are generated from simulation runs conducted during the Study, including

(i) projected yearly oil, condensate, gas, NGL, produced water, and source water production and injection volumes, for the pool;

(ii) projected composition of gas produced, sold, re-injected or used by year;

(iii) predicted average pool reservoir pressures by calendar year, starting at initial conditions;

(b) major assumptions used in simulations such as

(i) offsite disposition assumptions for production volumes for the TSR by year; and

(ii) fuel usage assumptions.

If Commission staff or consultants make written request of the Operator for permission to copy and remove other Data Room Information, the Operator, after consultation with the Owners, shall respond in writing on behalf of the Owners within 10 working days of receiving the request. A record will be maintained by Operator of all Data Room Information copied and removed from the Data Room.

4. The Owners have voluntarily offered to make Data Room Information available, subject to a request that the Data Room Information be held confidential under the provisions of AS 31.05.035(d) and 20 AAC 25.537(b). The Commission agrees that, unless held otherwise by a court of competent jurisdiction, the Data Room Information meets the standards of AS 31.05.035(d) and 20 AAC 25.537(b) entitling it to be held confidential. However, those confidentiality provisions do not apply to Data Room Information that is the same as information that has been otherwise submitted to the Commission without a claim of confidentiality, independently obtained by the Commission without a confidentiality obligation, or submitted to or obtained by the Commission subject to different confidentiality requirements, such as well data required to be filed with the Commission under AS 31.05.035(a). The expiration of the agreement does not affect whether documents entitled to confidentiality remain confidential.

5. Notwithstanding the provisions of paragraph 4, the Commission may make public periodic progress reports on the Study and the Commission's review of it if (1) public notice has been given under AS 43.82.410 relating to a proposed fiscal contract between the State of Alaska and a sponsor or sponsor group; and (2) the reports do not disclose substantive details of the interim Study results or of any Data Room Information. If the Commission desires to disclose in a progress report substantive details of the interim study results or of any Data Room Information, it will seek the written authorization of the Operator after consultation with the Owners, which authorization shall not be unreasonably withheld. The Operator shall, after consulting with the Owners, respond in writing to a request from the Commission for authorization within 10 working days of receiving the request.

6. The Operator shall provide written notice to the Commission when the Study begins and access to the Data Room is first available, which shall be not later than September 1, 2006. The Study shall continue without interruption for six months from the date it begins. The Study may be extended upon request by the Commission and approval by the Owners.

Relationship of the Study and Study Process Principles

to Other Commission Responsibilities and Actions

7. Nothing related to the Commission's access to and review of the Study -- including access to reservoir simulations and related studies, requests and suggestions with respect to reservoir simulations. and review of Data Room Information -- shall limit the Commission's ability to independently evaluate evidence submitted in future regulatory proceedings relating to TSR development (including determination of allowable gas offtake rate or other pool rules) ("Proceedings"). Further, nothing in the principles stated in this document shall limit the Commission's exercise of any of its statutory powers and responsibilities under AS 31.05, including but not limited to its right to undertake its own independent reservoir simulation studies.

8. Whether Proceedings are initiated by a petition by the Operator or are initiated by the Commission on its own motion, or are otherwise initiated, the Operator and Owners shall introduce as evidence in the Proceedings their TSR reservoir studies that best reflect a reasonable range of offtake options and their effects. The evidence shall include the data inputs and output, underlying engineering, geologic and geophysical information including petrophysical data, rock and fluid properties, and operating assumptions for the simulations. The Operator and Owners acknowledge that the Commission may request (including by subpoena) any other pertinent information, including but not limited to other

TSR reservoir studies that have been performed in the Study that were not included in their original submission of evidence in the Proceedings.

9. The confidentiality of Data Room Information as addressed in paragraph 4 above shall not affect whether any evidence introduced in the Proceedings will be entitled to confidentiality, even as to evidence whose contents are identical to that of Data Room Information. Claims of confidentiality for evidence in the Proceedings shall be determined by the Commission during the Proceedings under governing law.

CONFIDENTIALITY AGREEMENT GOVERNING THE SHARING OF INFORMATION DURING THE POINT THOMSON UNIT RESERVOIR STUDY PROCESS

1. The State of Alaska and the Point Thomson Unit Working Interest Owners ("Owners") are working to develop stranded gas resources on the Alaska North Slope, including gas resources in the Thomson Sand and the Pre-Mississippian Carbonate reservoirs (collectively, "TSR") within the Point Thomson Unit.

2. In anticipation of that development, the Alaska Oil and Gas Conservation Commission and the Owners have agreed to "Principles Governing Commission Access to Point Thomson Unit Reservoir Study Process" ("Principles"). The Principles refer to two processes: (a) the study process ("Study"), during which AOGCC staff or consultants will be allowed to monitor reservoir studies conducted by the Owners, and (b) the subsequent decision making process ("Proceedings") for determining allowable offtake from the TSR. The Principles establish confidentiality provisions relating to data to which AOGCC staff or consultants may have access during the Study process.

3. The Principles provide the opportunity for Commission staff and consultants to have access during reasonable working hours to a Data Room equipped with computers and software that will allow review, analysis, model visualizations, and report preparation with respect to TSR reservoir simulations and related studies. Accordingly, Commission staff and consultants will have access to data inputs and outputs and underlying engineering, geologic, and geophysical information, including petrophysical data, rock and fluid properties, and operating assumptions for the simulations (altogether, "Data Room Information"). Entry into the Data Room by Commission staff and consultants is subject to the signing of this Confidentiality Agreement ("Agreement") between Exxon Mobil Corporation ("EM") and the undersigned Commission staff or consultant.

4. Paragraph 3 of the Principles provides that

"Commission staff and consultants may take and retain notes during their review of Data Room Information. In addition, Commission staff and consultants may obtain copies in electronic form and remove from the Data Room the following categories of Data Room Information without additional permission by the Owners or Operator:

(a) simulation predictions that are generated from simulation runs conducted during the Study, including
   (i) projected yearly oil, condensate, gas, NGL, produced water, and source water production and injection volumes for the TSR;
   (ii) projected composition of gas produced, sold, re-injected or used by year;
   (iii) predicted average pool reservoir pressures by calendar year, starting at initial conditions;
(b) major assumptions used in simulations such as
   (i) offsite disposition assumptions for production volumes for the TSR by year; and
   (ii) fuel usage assumptions."

The undersigned agrees to the above and that a log shall be kept of any document copied; identifying the copied document and the date the copy was made. The log shall also identify who made the copy and who received the copy if different. If Commission staff or consultants seek to copy and remove other Data Room Information, they agree to make a written request to EM under the terms of Paragraph 3 of the Principles.

5. The undersigned

(a) certifies that he or she is a member of the Commission staff or consultant authorized by the Commission to participate in accessing Data Room Information;

(b) certifies that he or she has read the Principles and agrees to act in compliance with the terms and conditions of the Principles.

6. The undersigned agrees to keep all Data Room Information, including Commission and consultant work product that divulges Data Room Information, strictly secret and confidential in the same manner and to the same extent the Commission agreed such Data Room Information will be treated as confidential under paragraph 4 of the Principles, including an agreement not to release Data Room Information except to AOGCC Commissioners, AOGCC staff, and AOGCC consultants working on the TSR gas offtake analyses and to take precautions that are reasonably necessary to preserve the secrecy and confidentiality of such information using at least the standard of care he or she normally uses in protecting the Commission's or his or her own confidential information.

7. The undersigned agrees that the unauthorized release of confidential Data Room Information subject to this Agreement may adversely affect the proprietary interests of the Owners. In recognition of these interests, the parties agree that the Owners shall be entitled to seek injunctive relief without a showing of irreparable harm or damages.

8. The release of confidential Data Room Information does not make further releases permissible, and any failure to assert rights under this Agreement shall not be deemed a waiver of any rights under this Agreement.

9. This Agreement shall be interpreted and governed in accordance with the laws of the State of Alaska.

10. This Agreement shall be interpreted consistently with the Principles, which are incorporated into and adopted by this Agreement. In the event of any conflict between the provisions of this Agreement and the Principles, the Principles shall control.

11. This Agreement shall terminate December 31, 2016, provided however that if in the course of Proceedings any information whose contents are identical to that of certain Data Room Information becomes publicly available, that Data Room Information will no longer be subject to the confidentiality provisions of this Agreement. The expiration of the agreement does not affect whether documents entitled to confidentiality remain confidential.

IN WITNESS WHEREOF, the parties have executed this Confidentiality Agreement as of the dates beside their respective signatures

AOGCC EMPLOYEE OR CONSULTANT

Signature _____
Name: _____
Title: _____
Date: _____

EXXON MOBIL CORPORATION

By: _____
Name _____
Title: _____
Date: _____

MEMORANDUM STATE OF ALASKA

ALASKA OIL AND GAS CONSERVATION COMMISSION

TO: Chair John K. Norman
Commissioner Daniel Seamount
Commissioner Cathy P. Foerster

DATE: February 28, 2007

FROM: Jane Williamson
Sr. Reservoir Engineer

SUBJECT: Prudhoe Major Gas Sales Study

Blaskovich Services, Inc. (BSI) and Commission staff recently completed a study of the impact of a future Major Gas Sale (MGS) on oil and gas recovery from the Prudhoe Oil Pool. The following is provided as a summary of major findings and conclusions from this study.

Foreward – Historical Review and Study Purpose

In 1977, the Commission set the maximum allowable Prudhoe Oil Pool annual gas offtake rate at 2.7 billion standard cubic feet per day (BSCF/D), which contemplated an annual average gas pipeline delivery sales rate of 2.0 BSCF/D. This allowable, set out in Rule 9 of Conservation Order 341D, was approved without benefit of production history. The Commission recognized that the rates may be changed as production data and additional reservoir data became available.

Over the past five years, there has been significant activity concerning a potential major gas sale. BPXA, Exxon-Mobil, and ConocoPhillips commissioned a $125 million dollar study to determine the conceptual feasibility of a gas pipeline. The tentative plan resulting from this study was for a 4.3 BSCF/D pipeline, with capacity to expand to 5.6 BSCF/D. The Prudhoe Bay Unit, Prudhoe Oil Pool is the only North Slope developed field with significant gas reserves (estimated at more than 24 trillion cubic feet (TCF)) and is of primary importance for any decision concerning the pipeline. Pt. Thomson, with over 8 TCF of gas and several hundred million barrels of gas condensate and oil, was assumed to also provide a supply of gas for the pipeline. The companies and the State of Alaska have devoted significant resources to negotiate fiscal terms to build the pipeline. Based on these efforts, the Commission became concerned that no application for modification to the Prudhoe gas offtake rule had been submitted.

As a result of a Commission inquiry and several public hearings, the Commission published a report on December 5, 2005 concluding that there was a need to comprehensively revisit the question of the appropriate gas offtake limits in light of several decades of reservoir development and information that has become available since 1977. Because delay in the Commission's decision-making could disrupt the timetable for a potential gas pipeline project, the Commission adopted a proactive approach to ensure there would be an adequate factual basis for its eventual decision on

allowable gas offtake. The Prudhoe Working Interest Owners (WIO) and the Commission therefore agreed to principles allowing the Commission consultants and staff to access their reservoir simulation and other relevant engineering studies for the purpose of analyzing gas offtake rates and gas sales startup timing for the Prudhoe Oil Pool. Blaskovich Services, Inc. (BSI) was commissioned to provide reservoir engineering consultation in this study.

This work-study officially began in late January 2006. A brief summary follows:

Summary of 2006 Commission Audit Results

The Prudhoe WIO full field reservoir simulator was used as the primary tool in this evaluation. In addition to runs made assuming no gas sales, simulation runs were made at various gas sales rates (1.0-5.6 BSCF/D) and gas sales startup dates (2015, 2019, and 2024). Some simulation cases were run to test the impact of other factors such as changes in waterflood operation, fuel usage, CO_2 offtake, and some drilling/workover variations. We also evaluated the effect of varying assumptions for end of the field life (EOFL).

Throughout our analysis, we searched for major factors that would affect the trends in total hydrocarbon recovery as a function of gas offtake rates and timing. We were not searching for "the" optimum development strategy. We did not value one type of energy resource (e.g., liquids or gas) over another, but equated them using their relative energy content in units of barrels of oil equivalent (BOE). Based on our analysis of currently available data, we have reached the following major conclusions.

- A major gas sale at Prudhoe represents approximately an additional 4 billion BOE recovery.

- The latest WIO model needs improvements in its ability to predict future field performance. Model errors are increasing with time. Nevertheless, it is the best tool currently available. It should be suitable for comparing directional trends in energy recovery during a gas sale.

- Increased oil capture prior to gas sales can increase hydrocarbon recovery and result in recovery trends that are less sensitive to either gas offtake rates or gas sales startup dates. This was the only mitigation option evaluated that significantly improved trends in BOE recovery.

- End of field life (EOFL) is a major source of uncertainty in determining the gas sale strategies that will maximize energy recovery.

    - Comparison of model reserves predictions at the same date for EOFL tended to favor an earlier, higher rate gas sale. We found the time limit EOFL approach to be inappropriate because ending energy production rates could be vastly different between the high rate, early startup case and the low rate, delayed startup case.

- Model results based on equivalent EOFL rate limits consistently show that total energy recovery is substantially decreased with an earlier, higher rate gas sale. We believe that rate limits are more reasonable than time limits for comparison of gas sales model predictions. However, exclusive use of rate limits is flawed because the risks of wells and field infrastructure failures with age are ignored.

- Well, facilities and infrastructure failures can significantly increase the risk of lost hydrocarbons. The longer that gas sale is delayed, the greater the risk of well and facilities failure resulting in premature field shutdown. Furthermore, near term failures will defer production and may result in more reserves loss with early gas sales. Diligent efforts to maintain, repair, and replace aging wells and facilities will help to mitigate risks and maximize recovery under any sales scenario.

Recommendations

The Commission has not received a request for a new gas offtake rule. At this time, we cannot recommend a specific gas offtake rate and sales startup timing. The Prudhoe WIO model evaluations and studies that have been shared with us are not sufficient to justify an allowable above that specified in Rule 9, CO 341D. An early, high rate gas sale could result in the loss of a substantial volume of hydrocarbons. However, even greater volumes may be at risk if gas sales are indefinitely delayed and Prudhoe wells and infrastructure fail before these reserves can be recovered.

We are concerned that Rule 9 does not specifically require a plan for such a major change in the Prudhoe Oil Pool depletion strategy. The ultimate impact of gas sales on hydrocarbon recovery cannot be appraised in the absence of a proposed development plan that identifies the start date, sales rate and liquid loss mitigation efforts. Although the start-up for gas sales is a minimum of 8 years away, many decisions that affect the project will be made earlier. Depletion planning should be required prior to commitments to sell gas so that the Commission is adequately informed and assured that other factors do not exist that would justify or require action by the Commission.

Regardless of the timing of their submittal, the Prudhoe WIOs need to develop near-term strategies to prepare the field for gas sales with focus on methods to increase the capture of oil prior to gas sales and to ensure facility and well downtime is minimized. On a regular basis, the Commission needs to be kept informed of the progress of the depletion planning efforts, including review of study plans, reservoir study results and other relevant information that may impact the Commission's ultimate decisions concerning gas sales offtake. The exchange of information in the past year was very successful and a similar mechanism of exchange should be considered during the depletion planning stage.

We wholeheartedly appreciate the cooperation of the Working Interest Owners over the past year, particularly that of the BP technical representatives who worked with us in this endeavor.

This report reflects the evaluation and opinions only of the authors and does not necessarily reflect those of the Prudhoe Owners or other Commission staff.

Prudhoe Oil Pool
Gas Offtake Reservoir Study

Public Summary

February 28, 2007

Presentation Summary

- Commission authority
- Historical perspective
- Reservoir concerns related to gas sales
- Study purpose and available information
- Observations
- Recommendations

AOGCC Major Gas Sales Reservoir Study Disclaimer

Evaluation and opinions reflect those of only BSI and AOGCC staff who worked directly on the project. These opinions do not necessarily reflect those of the WIO, Commissioners or other AOGCC staff

Prudhoe Gas Offtake Allowable Commission Authority

- Commission Duties (related to MGS decisions)
  - prevent physical waste of resource
  - promote greater ultimate recovery
- Authorities
  - require/approve development plans
  - set allowable offtake

Prudhoe Gas Offtake Allowable Historical

- Pool Rules CO 341D, Rule 9 (1977)
  - Offtake allowable set at 2.7 BCFD
  - Envisioned ≈ 2.0 BCFD Pipeline Delivery
- Currently produced gas re-injected

Why do we care about gas offtake?

- Gas extraction lowers reservoir pressure
  - Decreases energy required for oil production
  - Oil recovery suffers; gas production benefits
- How is ultimate total hydrocarbon recovery affected by gas sales offtake?

Prudhoe Gas Offtake Allowable Recent Activities

- 2002 WIO study
  - Tentative P/L design of 4.3 BCFD
  - Prudhoe major source for P/L (+24 TCF)
- Pipeline fiscal discussions/negotiations
- No Application for Rule 9 Amendment
- AOGCC 2005 inquiry
  - Concluded comprehensive revisit of Rule 9 needed
  - Proactive Approach
  - "Principles" for access to WIO reservoir studies

Prudhoe Gas Offtake Study

- Study begun January 2006
  - Engineering Consultant Blaskovich Services Inc. (BSI)
  - WIO provided Data Room with necessary information and studies
- WIO Full Field Reservoir Simulator Primary Tool
  - Access/Electronic copies of reservoir simulation results
  - Additional simulation runs on request
- Good Cooperation from WIO staff, management

Study Approach

- Simulation runs variables
  - Gas Startup Times (2015-2024) Offtake Rates (1-5.6 BCFD)
  - Other field operating strategies
- Compared on basis of total energy content
  - Units of Barrel Oil Equivalent (BOE)
- Concentrated on trends in recovery, not absolutes
  - Not looking for "the" optimum development strategy

Conclusions

- Major Gas Sales adds ≈ 4 Billion BOE (+/- 24 TCF)
  - 11.4 BSTB Oil/Condensate/NGLs produced to date
  - 1977 projections of less than 9 Billion Barrel Oil
    - Initial projections assumed 1982 Gas Sales
    - End of Field life estimated 2003

Conclusions - Model

- WIO model best currently available
  - Years in development
  - Should be good for evaluation of directional trends
  - Some improvements needed in predictive mode

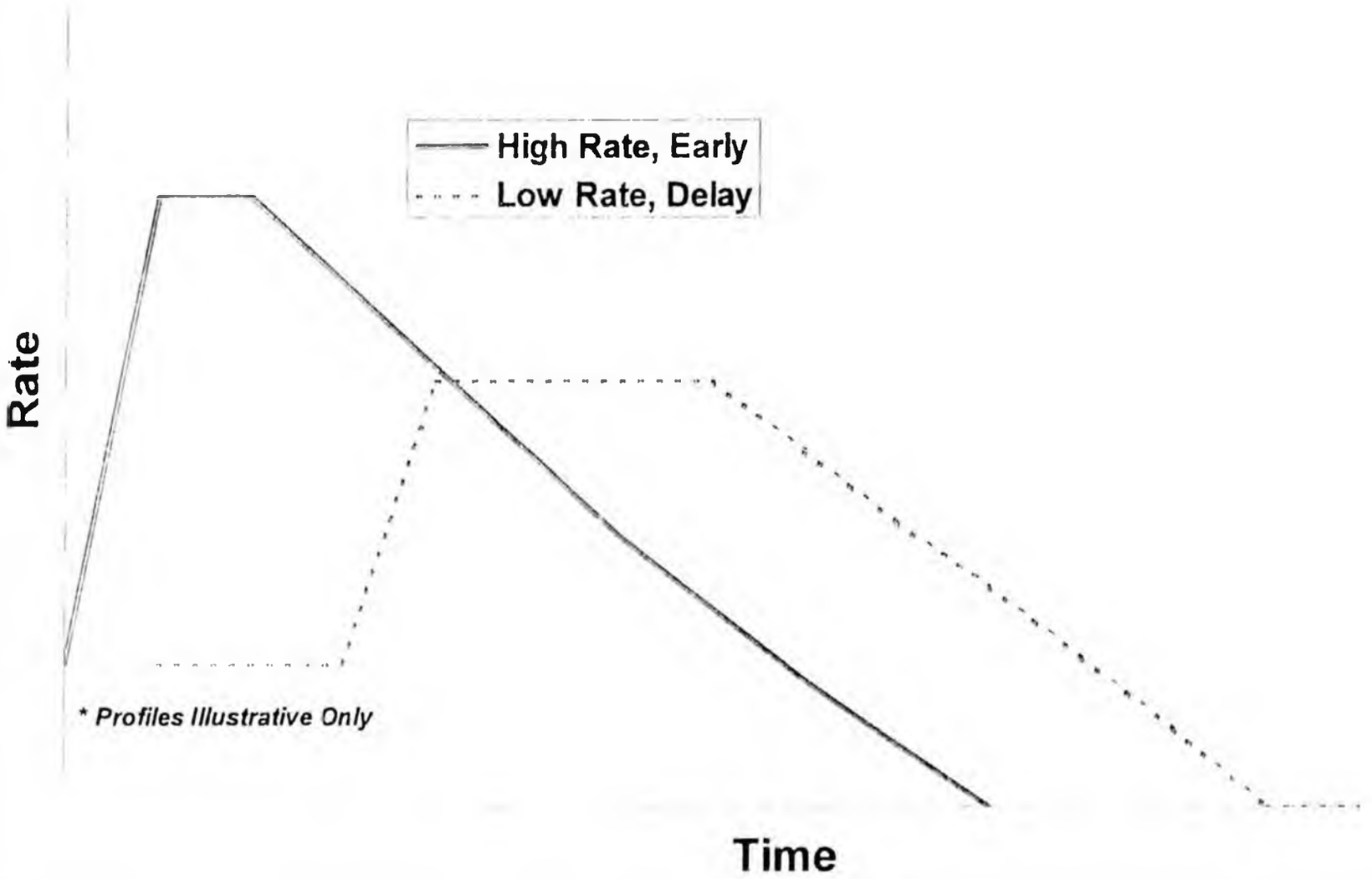
Conclusions

- ***Increased oil capture prior to Gas Sales***
  Improved recovery trends
  - Most encouraging strategy
  - Recovery trends less sensitive to gas offtake or S/U Rate
    - Allows for more flexibility

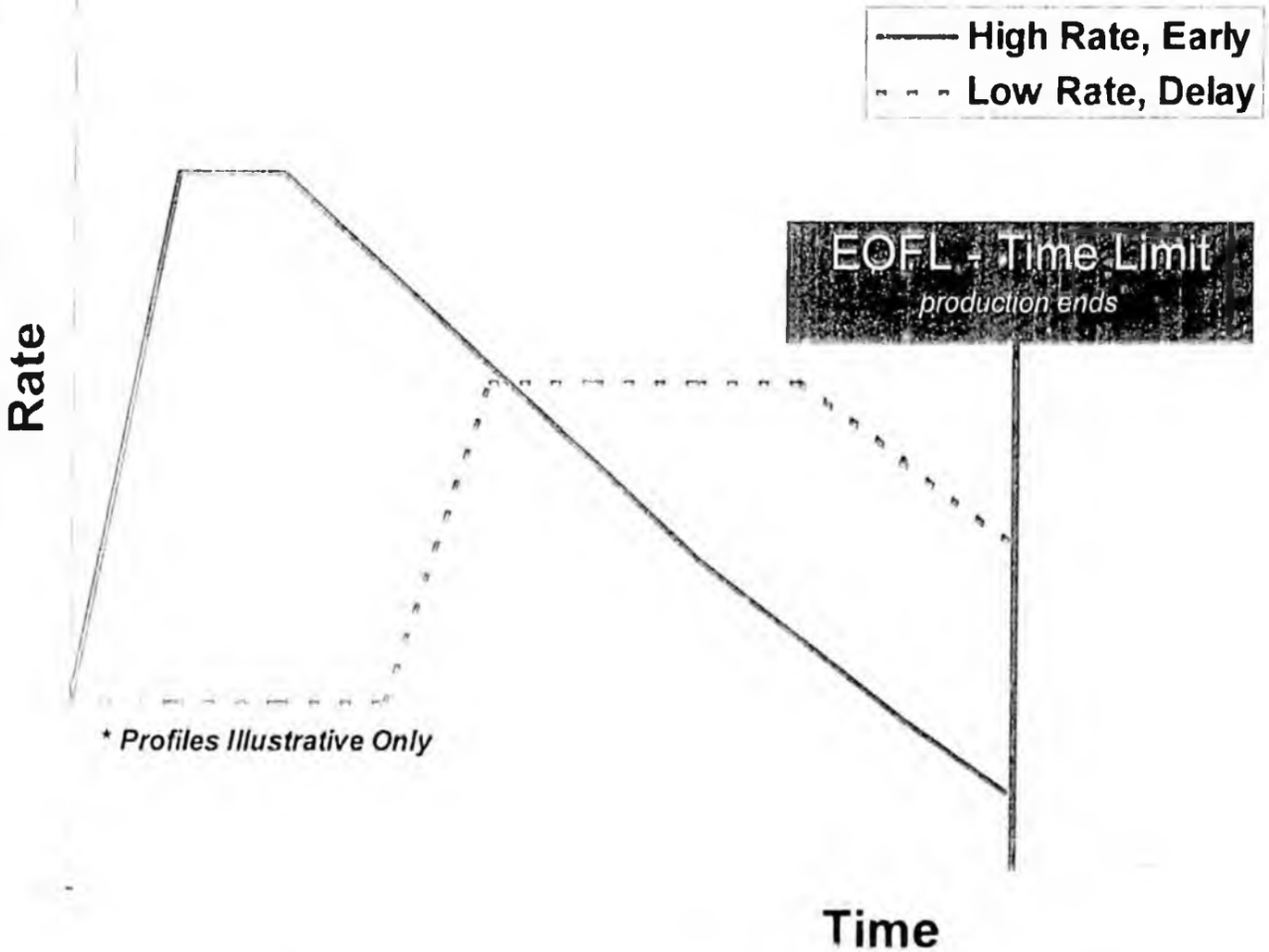
End of Field Life (EOFL)

- End of Field Life (EOFL) is when costs exceed revenue from continued production.
  - Reserves are evaluated at an assumed EOFL
  - Unknown – but important to compare all cases at same assumed EOFL
- Major effect upon predicted recovery outcomes
- Date Limit favors earlier, higher rate MGS
- Rate Limit favors later, lower rate MGS

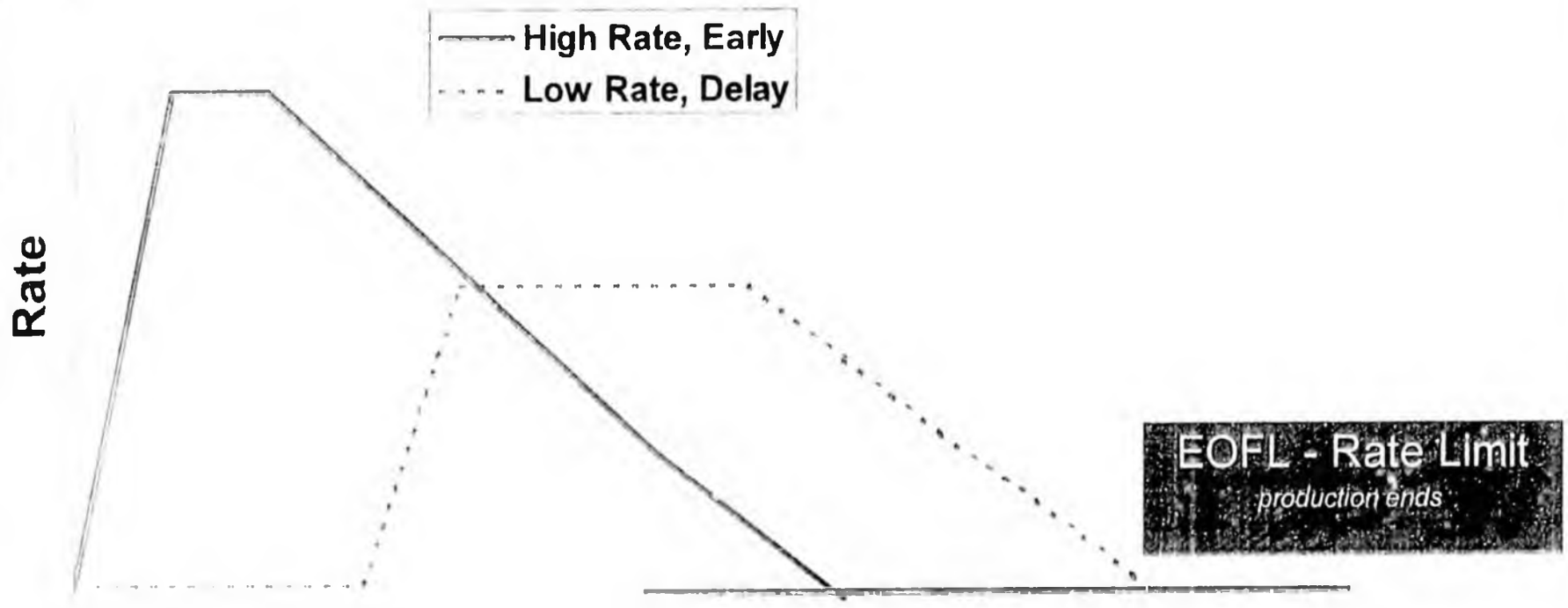
Hypothetical Profiles*



Hypothetical Profiles*
EOFL - Time Limit



Hypothetical Profiles*
EOFL - Rate Limit



** Profiles Illustrative Only*

EOFL Summary

- Time limits do not treat production (revenue) fairly.
- Rate limits do not treat future risk (costs) fairly.
- We believe rate limits are more correct but we need to consider risk with age.
- Use rate limits and risk analysis

Field Well/Infrastructure Failures

- Failures increase reserves risk
  - If MGS delayed
    - Higher risk with age– impact field life
  - Near Term failures
    - Deferred oil production prior to MGS risks reserves

Recommendations
MGS Offtake

- There is insufficient evidence at this time to recommend increasing Rule 9 Offtake
  - No request for modification of Rule 9
- Depletion planning should be required prior to commitments to sell gas

Recommendations
Pre-MGS Strategies/Plans

- Regardless of timing of request for modification near term strategies needed to prepare for MGS
  - Increase oil capture prior to MGS
  - Minimize well and facility downtime
- Mechanism needed for exchanging information during the depletion planning stage

Role of the Alaska Oil and Gas Conservation Commission in Establishing Allowable Gas Offtake Rate for Prudhoe Bay

The State of Alaska and other interested parties are engaged in determining how best to bring North Slope gas to market. The Alaska Oil and gas Conservation Commission ("AOGCC") has a very important role in this process – to protect the public's interest by preventing waste and insuring greater ultimate recovery of both oil and gas. To fulfill this role, the AOGCC will decide what gas production rates should be allowed from Prudhoe Bay and other North Slope oil fields. Considering only the laws of science, these decisions are very simple; to prevent waste and insure a greater ultimate hydrocarbon recovery, produce all of the oil in a reservoir first and then "blow down" its gas cap only when there is no commercially recoverable oil left. The AOGCC recognizes, however, that many other factors will – and should – be considered in exercising its regulatory powers.

Before considering other factors, it is essential first to understand the science. Extracting gas from an oil field like Prudhoe Bay triggers a series of events. First, the pressure in the gas cap decreases and becomes lower than the pressure in the oil-bearing part of the reservoir. As driven by the laws of physics, the reservoir then works to get back to equilibrium, i.e., the same pressure throughout. To do this, some oil, which is at a higher pressure, moves up into the lower pressure gas cap and the pressure in the oil-bearing part of the reservoir drops. This process continues as the pressure throughout the reservoir equalizes at a lower pressure than before. And as more gas is withdrawn, the process repeats, causing more oil to move into the gas cap and also causing the reservoir pressure to decrease further.

Both the movement of oil into the gas cap and the decrease in reservoir pressure jeopardize oil reserves.

Let's look at movement of oil into the gas cap first. Think about what happens when you drain the oil from your car or when you pour cooking oil into a measuring cup. When you empty the container, some of the oil sticks to it and will not come off. That is what happens to oil when it moves into the gas cap, a part of the reservoir that has never contained oil but has always only held gas. However, because that container is porous rock rather than glass or plastic, the amount of oil that sticks is much greater. The previously "dry" reservoir rock becomes coated with oil. Although some of this oil can be produced, a substantial portion (in some fields over 20 to 30 per cent) sticks to the rock and will never come out. In short, producing gas without replacing the gas cap fluids will cause some oil to stick to the reservoir rock and result in a decrease of ultimate recovery of oil.

Now let's look at decreasing reservoir pressure. Think about an aerosol container. It starts out with high pressure inside; if you puncture it, it will explode. As you use it, more and more of the fluids – both the active product and the carrier gas -- are released and the pressure decreases until, eventually, you push the button and nothing happens. When you shake it, you might be able to hear that there is still hair spray or some other product inside, but you can no longer get it out. At this point the pressure has decreased so that you could even puncture the container and nothing would happen. Similarly, in an oil reservoir, the reservoir pressure provides the energy that allows the oil to flow through the reservoir and up the well bore. As fluids are produced, the

pressure decreases and the reservoir loses this energy. Eventually, as more and more gas is produced and the pressure continues to drop, there is insufficient energy to drive the oil from the reservoir. Typically operators of oil reservoirs maintain reservoir pressure and energy by re-injecting produced gas and injecting water to replace produced oil. They continue this process until they have recovered all the oil. Then, when no commercially recoverable oil is at risk, they "blow down" the gas cap. They do this because producing gas from an oil reservoir and not replacing it will result in a decrease of reservoir energy and, therefore, a decrease in oil recovery.

Another bad thing happens when the reservoir pressure decreases; some oil changes from liquid to gas. The remaining oil becomes thicker. Think about soup cooking; as water evaporates, the remaining liquid becomes thicker. In an oil field this thickening makes it harder for the oil to flow and, thus, decreases oil recovery. We all know that it is much easier to suck water up a straw than it is molasses.

In summary, looking simply at the reservoir engineering science, producing gas from an oil reservoir while there is still commercial oil remaining to be produced WILL cause a portion of the oil resources to be lost and, thus, the gas cap in an oil reservoir should only be "blown down" when no more commercially recoverable oil remains.

The explanation above assumes that all of the gas can be recovered after all of the oil has been produced, and for most Lower 48 scenarios this is a reasonable assumption. However, for the North Slope, there will be a trade-off between leaving oil in the ground and leaving gas stranded, and this trade-off will be influenced by several factors.

For example, the remaining useful life and increasing operating cost of the aging North Slope infrastructure will impact this balance between losing oil and stranding gas. Much of the North Slope infrastructure that was put in place thirty years ago for oil production will still be necessary for gas production. As this infrastructure ages, two things happen: 1) the cost to operate the equipment increases, and 2) components break and must be repaired or replaced. The later in time the gas is produced the higher the costs will be to operate, repair and replace equipment and, thus, the sooner the gas will become uneconomical to produce and the more gas will be left stranded.

The minimum rate at which TAPS can operate will also impact the balance between losing oil and stranding gas. Although the gas will have its own line which will operate independently of TAPS, continued operation of the TAPS line will impact the economic life of the gas production because, as long as TAPS is operating, many of the operating, repair and replacement costs will be shared by both the oil and gas production, thus extending the time before either becomes uneconomical.

These and other factors will complicate the gas off take rate and timing decisions for North Slope fields. The AOGCC is charged with preventing waste and insuring the greater ultimate recovery by making sure that the operators act in accordance with good oilfield engineering practices. In executing this responsibility, the AOGCC must be cognizant of the balance between oil recovery optimization and gas recovery optimization. This will be no trivial task.

Role of the Alaska Oil and Gas Conservation Commission in Approving Pool Rules for the Point Thomson Field

The State of Alaska and other interested parties are engaged in determining how best to bring North Slope gas to market. The Alaska Oil and Gas Conservation Commission ("AOGCC") has a very important role in this process – to protect the public's interest by preventing waste and insuring greater ultimate recovery of oil and gas. To fulfill this role, the AOGCC must determine what gas production rates should be allowed from North Slope oil fields. As part of this process, the AOGCC will evaluate ExxonMobil's proposed plan to develop the Point Thomson Field as a gas field rather than as an oil field. Generally, the most total hydrocarbon recovery from a retrograde condensate field would be achieved by conducting gas cycling operations to produce condensate (a liquid hydrocarbon that is considered "oil" under the Commission's governing law) until all of the economically recoverable liquid hydrocarbons have been produced. Only then should the gas be sold. The AOGCC recognizes, however, that many other factors will – and should – be considered in exercising its regulatory powers.

Point Thomson is the largest proven yet still undeveloped field in Alaska. It is also one of the most difficult to develop and manage properly because the majority of the resources are contained in what is called a retrograde condensate reservoir. Retrograde condensate reservoirs around the world tend to be deeper and have higher pressures and temperatures than conventional reservoirs. These abnormally high temperatures and pressures cause the fluids in the reservoir to have unusual properties. Thus, a retrograde condensate reservoir acts differently than a typical oil field such as Prudhoe Bay or a typical gas field such as the Kenai Gas Field. The differences in behavior are technically complex and difficult to describe, understand, and address; yet understanding and addressing these differences are essential to evaluating whether a plan of development satisfies the conservation requirements administered by the Commission.

A conventional oil reservoir is typically filled with a liquid hydrocarbon that has some solution gas in it. In such a reservoir all the fluid exists as a liquid, but as it is brought to the surface its pressure drops and some of its solution gas is released. The same thing happens underground. As the pressure decreases in the reservoir, gas in the oil comes out of solution. To understand how this works, think of a bottle of soda. Before the bottle is opened, its contents are under pressure and it appears that there is just liquid in the bottle. However when the cap is removed, the pressure in the bottle is reduced and bubbles will start to form and float to the surface of the soda.

Conversely, a conventional gas reservoir is typically filled with hydrocarbon gas. The gas may have a small amount of hydrocarbon liquid, called condensate, vaporized in it. This condensate will not drop out as a liquid in the reservoir because the temperature is too high. However it will separate from the gas when the gas is brought to the surface where the temperature is lower. This is similar to what happens when someone blows warm breath onto a cold window and watches it fog up. The water that exists as a vapor inside the warm lungs turns to condensation as it hits the cold window.

Retrograde condensate reservoirs do not behave in the same ways that conventional oil and gas reservoirs do. Dropping the pressure in the reservoir does not cause gas to form from oil, as is the case in a conventional oil reservoir. Nor does vaporized condensate remain a vapor, as is the case in a conventional gas reservoir. Rather, for a retrograde condensate reservoir, as the pressure decreases, liquids drop out of the gas in the reservoir.

When a retrograde condensate field is produced like a conventional gas field, the gas is produced and sold at high rates. Initially a large amount of condensate is produced with the gas. However the reservoir pressure drops quickly and condensate production drops dramatically because condensate is dropping out in the reservoir instead of at the surface. To further the problem, condensate that drops out in the reservoir is much more difficult to produce than that which remains entrained as a vapor in the gas. The liquid tends to build up and clog the pore spaces in the reservoir rock. Also, since this reservoir has never been exposed to liquid before, the rock acts as a sponge and some of the condensate will be immobilized and never come out. To make things worse, once the condensate comes out of the gas, very little of it will return to a gaseous state even if the reservoir pressure is later increased. In other words this is a problem that you can't fix after you cause it; it's like unringing a bell.

In addition to lost condensate recovery, if the reservoir pressure is reduced too quickly, the gas recovery will also decrease. The condensate that clogs up the reservoir and won't come out also blocks the gas from coming out. This is similar to an air filter on a car. When the filter is new, air will flow through it freely, but as it gets older the pores in the filter begin to clog with dirt (as the pores in the reservoir would clog with condensate) and the air will not flow through as well. Eventually no air at all will flow.

So what's the answer? To maximize condensate production from a retrograde condensate reservoir, it is necessary to keep the reservoir pressure high until the condensate has been recovered. Often this is accomplished through a process known as "gas cycling." In this process hydrocarbon gas is produced, the condensate is removed and sold, and the now-lean gas is injected back into the reservoir to maintain pressure and to sweep more condensate to the surface. As this process continues, the gas produced slowly becomes leaner and the yield of condensate decreases. Eventually the gas is stripped of most of the liquids and it is safe to sell the gas. This method delays gas sales, but it results in greater ultimate recovery of both liquid and gaseous hydrocarbons.

Another method used to develop retrograde condensate fields is to inject a substitute gas such as nitrogen or carbon dioxide either to replace or to supplement the produced gas for pressure maintenance. Unfortunately, there is currently no substitute gas available to Point Thomson.

These are just a few of the more common methods used for developing retrograde condensate fields and each has advantages and disadvantages that must be considered. Primary depletion as a gas field is the least efficient and results in the lowest hydrocarbon recovery. However, it is the simplest and cheapest method for the operator since it does

not require an investment in equipment to recycle the gas. Gas cycling yields greater hydrocarbon recovery but may be less attractive to the operator because it has a higher up-front development cost for compression and it has low up-front cash flow due to the deferral of gas sales. Injection of outside substances has the possibility of maximizing both condensate recovery and cash flow, but it is the most expensive method because in addition to compression equipment it requires the purchase of a substitute gas.

Selection of an optimal method of development must consider all of the unique aspects of the reservoir in question, as well as the practicality and applicability of the various development methods.

The operator of the Point Thomson Unit has indicated that the only development scenario that makes sense is to develop Point Thomson as if it were a normal gas field, which would likely result in significant loss of condensate. Since the AOGCC must determine whether this development option is consistent with good oilfield engineering practices and will result in greater ultimate recovery, the agency is working with an outside consultant who has extensive retrograde condensate reservoir expertise. The AOGCC and its consultant are evaluating different development options and developing a sound technical basis for conservation orders relative to the development plan that is ultimately proposed by the operator of the Point Thomson Unit.

Role of the Alaska Oil and Gas Conservation Commission in North Slope Gas Sales

The State of Alaska and other interested parties are engaged in determining how best to bring North Slope natural gas to market. The Alaska Oil and Gas Conservation Commission ("AOGCC") has an important responsibility in this process – to protect the public's interest by preventing waste and insuring greater ultimate recovery of oil and gas. To fulfill this role, the AOGCC must determine what gas offtake rates should be allowed from North Slope fields, most notably the Prudhoe Oil Pool and the Pt. Thomson gas condensate reservoirs.

There are over 35 trillion cubic feet of gas reserves within these two fields. However, hundreds of millions of barrels of oil and condensate could be lost if gas offtake from these fields is not correctly managed.

In general, maintaining reservoir pressure enhances oil recovery, but producing gas depletes reservoir pressure. Therefore, gas reserves in most fields are usually sold only after the liquid hydrocarbon reserves have been depleted. Until then, the gas that is produced is used to promote liquid production in various ways (including being reinjected so that it can provide the energy needed to get the liquid hydrocarbons to the surface and providing a source of gas for miscible injectant used in enhanced oil recovery operations). And that is exactly what is happening right now at Prudhoe Bay and other North Slope fields.

The North Slope gas sales project will ultimately involve trade-offs between oil and gas recovery. The documents *Role of the Alaska Oil and Gas Conservation Commission in Establishing an Allowable Gas Offtake Rate for Prudhoe Bay* and *Role of the Alaska Oil and Gas Conservation Commission in Managing Development of the Point Thomson Field* explain these trade-offs. This document explains the process the AOGCC is using to insure greater ultimate total hydrocarbon recovery, i.e., recovery of both oil and gas, as the North Slope gas project moves forward.

Normally, the operator of an oil or gas field applies to the AOGCC for "Pool Rules." These are specific rules that stipulate how to develop the reservoir in a way that maximizes oil and gas recovery. However, the Point Thomson Owners have not yet applied to the AOGCC for Pool Rules.

Nor have the Prudhoe Owners applied for amendment of current pool rules to allow for a higher gas offtake rate. The existing Prudhoe gas offtake rate was set in 1977 at 2.7 billion standard cubic feet (BCF) of gas per day. After deducting gas used as fuel and in enhanced recovery operations, this leaves about 2 BCF of gas per day available for sales. However, the gas sales scenarios that are being discussed publicly could require increasing the Prudhoe gas offtake allowable.

Normally the AOGCC would wait for an application from the Owners before performing the reservoir studies necessary to establish or increase gas offtake rates. However, that would delay the AOGCC's decision-making such that it could disrupt the timetable for a potential gas pipeline project. (The AOGCC needs to complete its evaluations and make its rulings for both

Prudhoe Bay and Pt Thomson so the Owners have approved gas offtake allowables that they can use in the "open season" process that is required under the Federal Energy Regulatory Commission ("FERC") regulations. The current draft version of the Alaska Stranded Gas Fiscal Contract requires the Producers to apply to the AOGCC within 6 months of the effective date of the contract for issuance of pool rules to authorize the field gas offtake rate for Point Thompson.)

Therefore, the AOGCC has chosen a proactive approach. There are two ways the Commission might take a proactive role with respect to such studies. One would be to conduct or arrange for consultants to conduct independent reservoir studies. The other would be to participate with the Owners and operators in their reservoir simulation studies, so that questions can be answered and adjustments can be made up front. Assuming adequate cooperation on the part of the Owners, the latter approach has significant advantages: lower cost to the State of Alaska, less time required to complete evaluation of the studies, more complete and accurate input data, and use of proven, probably more sophisticated reservoir evaluation tools.

In 2005 the Commission held hearings to inquire whether the gas offtake rate from Prudhoe should be updated. The AOGCC decided that, although the 1977 allowable was based on the best available data at the time, the appropriate gas offtake allowable must now be redetermined using the almost thirty years worth of reservoir description and performance information that has become available since 1977. Further, the Prudhoe Owners and the AOGCC established principles by which to perform collaborative studies. The report of the inquiry and the resultant study principles were issued by the AOGCC on December 5, 2005.

The AOGCC has contracted reservoir evaluation consultants to assist its technical staff in performing the Prudhoe study. The Prudhoe Owners have agreed to provide the AOGCC staff and consultants access to their simulators including the underlying engineering, geologic, and geophysical information. A data room has been set up in BP's Anch ge offices, equipped with computers and software allowing review of the simulator results. The Owners have voluntarily offered to make the data room information available. The information meets the standards of AS 31.05.035(d) and 20 AAC 25.537(b) entitling it to be held confidential during this study period.

This study process began in January 2006, and is anticipated to be complete by the end of this year. Following this study period, either the Owners will submit an application to amend the Prudhoe gas offtake allowable or the AOGCC will call for a hearing. In either case, the AOGCC will hold public hearings to review the development plans associated with the proposed gas sales. The Owners will be required to submit for the record reservoir studies that best reflect a reasonable range of offtake options and their effects. The AOGCC may request (including by subpoena) any other pertinent information that has been used in the study but is not included in the Owners' submission of evidence in the hearings. Claims of confidentiality for evidence in the hearings will be determined by the AOGCC during the course of the hearings under governing law.

On April 26, 2006 the AOGCC and the Pt. Thomson Owners agreed upon a similar process for studying the allowable gas offtake from that field. The AOGCC has contracted reservoir evaluation consultants to assist its technical staff in performing the Pt Thomson study. AOGCC staff and consultants will have access to a data room in ExxonMobil's Houston offices. The data

room will include reservoir engineering, geologic and simulation information and will be equipped with computers and software allowing review of the simulator results. The study will begin before September 2006 and will last up to six months. The Point Thomson Owners have indicated they plan to apply to the Commission in late 2006 or early 2007 for Pool Rules and a gas offtake allowable rate.

ALASKA AFL-CIO

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VINCE BELTRAMI
Executive President

BRUCE LUDWIG
Secretary / Treasurer

May 5, 2007

Chairman Chenault and other esteemed members of the House Finance Committee:

Thank you for the opportunity to testify. My name is Vince Beltrami and I am president of the Alaska AFL-CIO.

I would like to thank the Governor for the process that AGIA lays out. One thing is clear whether you agree or disagree with the AGIA strategy. No one in this state car. say our Governor does not want to build a natural gas pipe line.

No one has offered up a better, fairer alternative. Speaking on behalf of the 60,000 Alaskan members the AFL-CIO represents, the Alaska AFL-CIO supports the AGIA in its present form; specifically, the component which includes a project labor agreement. I was happy to see the Governor's message in the April edition of the Labor Department's Trend publication, which demonstrates the Governor's commitment to and understanding of what it is the PLA brings to the project.

In order to train a workforce for this project, it is necessary to align with the best craft training available in the state. No one disputes the union apprenticeship programs do it best. We've been training for years, we are training now, and we will ramp up more and further training when an agreement is done.

Discussions we have had with oil company folks, discussion with our US delegation, and with most of our state legislators show that a PLA is widely believed to be a necessary component of a project like this.

My opinion is that this component and others in the Governor's plan may try to be leveraged to make this bill fail. If so, that in itself, would be a tragedy not unlike the PPT debacle, serving the interests of a few instead of the interests of the many.

To demonstrate what goes on regularly, and the commitment the unions are, and have been, making to Alaskans, I would like to submit for the record a DVD I made yesterday. I was speaking with the training director of the NECA/IBEW training program on Thursday (May 3rd) when he mentioned he had eight students doing a 72 hour class at the facility on residential electricity. The

and all enrolled in an Alaska Works Partnership program

students, all Alaska natives from the Bethel region, were in the midst of training as we spoke. With no afore knowledge, rehearsal, or set up, I drove over to the school with my video camera, stepped out of my vehicle and recorded a few minutes of something that goes on all the time; the union apprenticeship programs training Alaskans at our facilities and out in the rural communities.

And we stand ready to train an Alaskan workforce to build a natural gas pipe line. Also, noteworthy, is all the training we do, comes at no expense to those getting the training. Employer contributions negotiated with the unions and, in some cases, supplemental monies from programs like STEP, help assure that Alaskans will be trained with little more than an investment in time and motivation. Our training records are a testimony to that fact.

While I respect the investment our producers have made in this state, I believe that Alaskans will be best served by using a process like AGIA to reach our ultimate goal: putting Alaskans to work to build a thriving economy.

Thank you for the opportunity to testify. I know and appreciate the fact that you are all working hard, and I urge you to continue to work hard for the passage of AGIA for the benefit of all Alaskans!

Sincerely,

Vince Beltrami

Vince Beltrami
President
Alaska AFL-CIO

The Alaska Gasline Inducement Act and Alaska Hire

By Governor Sarah Palin

I have long recognized that AGIA must not only induce a gasline, but also must provide Alaskans real opportunities for gasline-related employment. This means offering vocational programs to train Alaskans for pipeline jobs, as well as assuring that Alaskans will fill those jobs. AGIA fulfills these goals in six ways.

First, AGIA requires that applicants commit to hire Alaskans for management, engineering, construction, operations, maintenance, and other gasline-related positions, and to contract with Alaska businesses to the extent permitted by law. Note that jobs to be filled are not short-term construction positions; we want Alaskans trained and experienced in all facets of this project, including its maintenance and management for the 40 or 50 years it is producing. Remember that the requirement is not limited to simply hiring Alaskans but to contracting with Alaska businesses to do pipeline work, which will expand the scope of the pipeline's impact on careers in Alaska.

Second, the AGIA requires that applicants commit to establishing a local headquarters in Alaska. This is an important requirement since project management will be coordinated in Alaska, enhancing the likelihood that management positions will be staffed by Alaskans.

Third, applicants must commit to negotiate a project labor agreement. A project labor agreement is basically a pre-construction bargaining agreement between management and labor, specific to the project. Under a PLA, costs are established for labor, including wages, benefits, and working conditions. PLAs provide a host of assurances for both management and workers. Stability in labor cost estimates lessens cost overrun risks. No-strike/lock-out agreements assure there are no management-labor disputes for the duration of the project, which promotes on-time delivery of project milestones. Local hiring halls can be established. Apprenticeship requirements would offer Alaskans the opportunity to learn on the job, with pay and benefits. PLA language would allow bidding for any pipeline-related work to be open to any qualified firm, union or non-union.

Fourth, AGIA requires the Commissioner of Labor and Workforce Development to develop a job training program for pipeline-related positions. It is so important to train a skilled Alaskan workforce and we are committed to doing this right. As an added benefit, it serves as an inducement to the licensee, which would prefer that the state handle this responsibility. We are pleased to do so.

Fifth, if explorers get financial terms that enable them to economically explore for, discover, and transport new gas to and through the line, it opens the North Slope basin to not just marketing the known 35 trillion cubic feet of gas there, but to the additional hundreds of trillion cubic feet of gas waiting to be discovered. A gasline that will transmit hundreds of trillions of cubic feet of gas for 40 or 50 years is a critical means to provide long-term vocational stability to Alaska workers.

Last, AGIA requires that the applicant commit to provide for a minimum of five delivery points of gas in Alaska. Off-take points from the main line provide opportunities for spur lines to fuel Alaska homes and businesses with Alaska gas. In-state delivery also requires additional infrastructure, which in turn requires additional personnel to build and maintain the infrastructure.

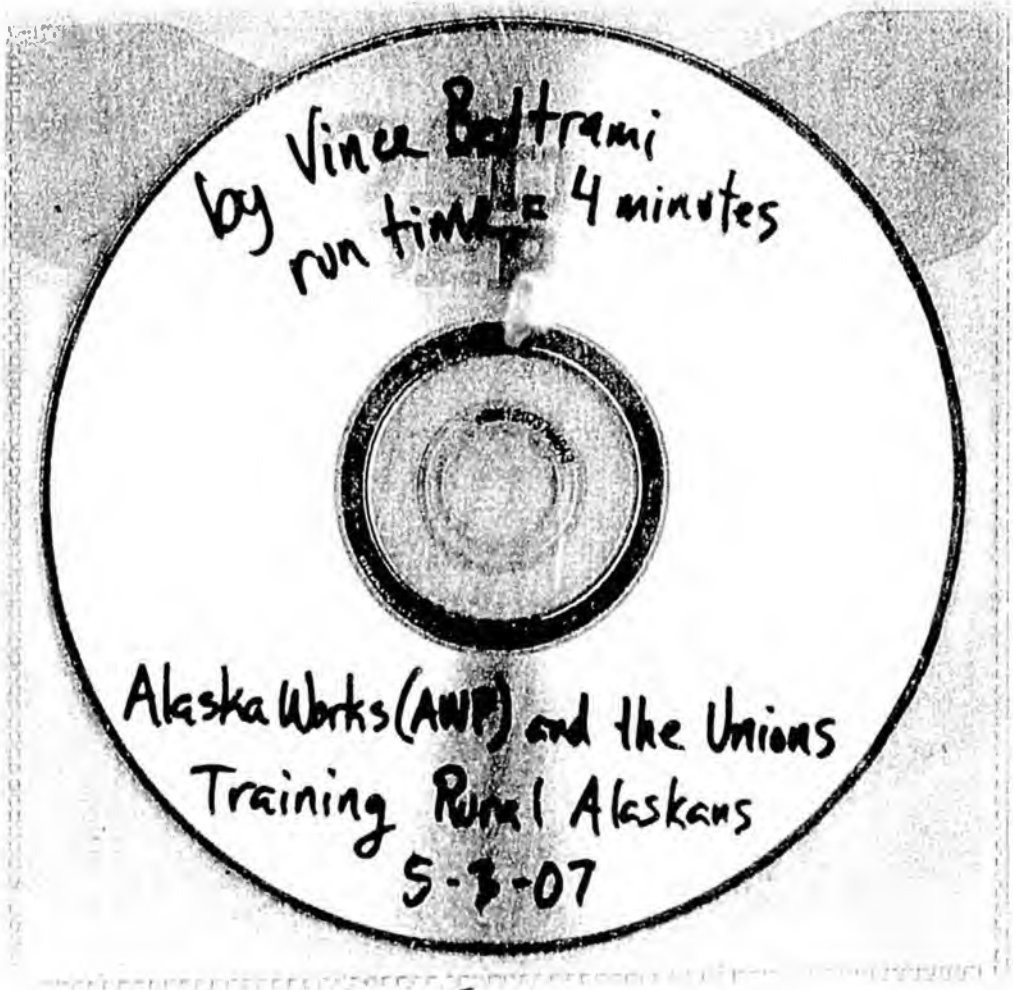
I believe strongly in offering Alaskans the best and most meaningful opportunities to capitalize on work generated by AGIA and the gasline it will facilitate. AGIA does that – it offers Alaskans not just jobs, but careers.

The above paragraphs are excerpts from Governor Palin's weekly Alaska Gasline Inducement Act briefing on Alaska hire. For further information on AGIA, please visit our website at http://www.gov.state.ak.us/agia/.

THE FOLLOWING DOCUMENT

HAS NOT BEEN FILMED BUT IS

AVAILABLE IN THE ORIGINAL FILE


by Vince Beltrami
run time = 4 minutes
Alaska Works (AWP) and the Unions
Training Rural Alaskans
5-3-07

DOWLAND—BACH
db
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P.O. BOX 230126
ANCHORAGE, ALASKA 99523-0126
(907) 562-5818

RE: House Finance Committee Testimony (HB 177) May 5, 2007

Good afternoon Chairmen Chenault and Meyer, Co-Chair Stoltze and other esteemed and distinguished members of the House Finance Committee. My name is Lynn Johnson and as most of you know, I am the President and co-founder of Dowland-Bach Corporation and a past President of the Alaska Support Industry Alliance. First of all, I would like to thank you all for all of your diligent and thoughtful work to date on AGIA and HB 177. I suspect that you all have had numerous visits, e-mails and phone calls recently on this subject. The reason for all of this fuss is that Alaska needs to get going on a gas project now, not later. It appears to me that we are now farther away than ever from passing any legislation enabling construction of our natural gas pipeline to the lower 48. The three major players now say that they are not even going to bother to submit a bid and apply for a state license to build the North Slope gas pipeline. Without their participation, the probability of Alaska ever getting a gas pipeline is close to zero. We were much closer to a pipeline twelve months ago and it seems to be getting worse by the day.

As a businessman doing business with the producers, I obviously have empathy for their position, but this anti-big oil rhetoric has got to stop. Taxes on the oil portion of their current business provide 88% of our current state revenue and have done so for years, and this is how we treat them?? We need to make key changes to this bill prior to passage, including ones that include eliminating exclusivity and replacing prescriptive mandates with objectives.

In summary, if businesses such as mine are going survive, we all need to encourage the building of a gas pipeline in the near term by those capable of doing it. AGIA may well be the last chance at having this construction actually take place, and if we fiddle around for another five or six years, some other gas from another basin is going to fill the need in the Mid-West and Alaska gas will no longer be in such high demand. Let's fix AGIA and then pass it by ensuring that it addresses the needs of Alaskans, of the developer and transporter and of North Slope producers and shippers. It's Time. Thanks

Testimony regarding House Bill 177
May 5, 2007
By
Kelly Patrick, Alaska State Resident

Co-Chairmen Chenault and Meyer's, members of the House Finance Committee:

Good afternoon, my name is Kelly Patrick. As a long time Alaskan and an active participant in the community and public affairs, I appreciate your scrutiny and close examination of the bill as drafted by the Governor.

Oil revenue currently accounts for 90 percent of the states budget. Alaska North Slope oil production is decreasing and will continue to do so with the States budget situation becoming critical well before 2016. Certainly the House more than anyone understands the need to move swiftly and decisively towards replacing our oil based economy with a more diversified economy based on natural gas.

I am concerned that in the Governor's desire to be fair to all, we now have a bid process that does not contain the clear and objective criteria for the evaluation of applications that I would anticipate in any bid process. I am also concerned that providing a $500 million incentive would encourage those without the financial strength to carry through with a project of this size. Most RFPs (or, in this case an RFA) that the normal business community contractors respond to have to show proof they have the financial wherewithal to pay their employees and are very specific that any expenses incurred during the course of the bid are not reimbursable. As a prudent business person, I would expect the State of Alaska to make the same requirement.

I also have to concur with previous testimony that points out that the State of Alaska needs to improve their internal processes in selecting project winners in an effort to reach a more productive and beneficial outcome for the people of the State of Alaska. The selection of this Licensee needs to follow a formalized, logical objective course. Any subjectivity in selection needs to be eliminated.

We all talk about making sure that we have future jobs for our children and grandchildren, as they are the ones who will continue to make Alaska prosperous. With the continual decrease in oil production to keep TAPS filled, it is imperative that we do not fail in getting an acceptable bid process in place preferably prior to the end of the first half of this legislative session.

I thank you for your time. I know that you want to do what is best for the State of Alaska and for its future generations. I ask that you make certain that HB 177 accomplishes that mission.

Kind regards,

Kelly Patrick

UDELHOVEN
Oilfield System Services, Incorporated

184 East 53rd Avenue
Anchorage, Alaska 99518-1222
(907) 344-1577 Fax (907) 522-2541

Mr. Chairman, members of the committee.

Thank you for the opportunity to testify on the AGIA Bill. My name is Jim Gilbert, and I'm President and testifying on behalf of my company, Udelhoven Oilfield System Services.

Our 400-plus employees provide technical expertise to the oil and gas industry in Alaska, the Gulf of Mexico, Tbilisi, Georgia and Bohai Bay, China.

First and foremost, we want a gas project ... sooner rather than later, and with the greatest long-term benefits for the State of Alaska, Alaskan workers, Alaskan businesses and all Alaskans. North Slope gas commercialization holds the key to Alaska's future.

We understand the importance and urgency of transforming our gas potential into a gas project. The opportunity to market our gas won't last indefinitely, and there's a very real risk of losing it altogether if we don't act quickly.

Agia needs fixing, listen to the producers and follow their lead.

Both the state and shippers need to be involved in and have oversight of a project execution plan that provides the greatest netbacks at the wellhead. A third-party pipeline builder with no production interests will have no incentive to reduce costs and no ability to "guarantee" the tariff in advance.

The Alaska Gasline Inducement Act may be our last and best chance to make a North Slope gas project a reality, but only if it's fixed before it's passed. In order to succeed, the bill must acknowledge the interests of Alaskans, and of North Slope producers and shippers.

Thank you.

Jim Gilbert
184 E. 53rd Ave
Anchorage, AK.

Alaska Trucking Association, Inc.
3443 Minnesota Drive · Anchorage, Alaska 99503 · Phone (907) 276-1149 · Fax (907) 274-1946
www.aktrucks.org

Aves Thompson, Executive Director
Alaska Trucking Association
House Finance Testimony, HB177
Saturday, May 5, 2007

Thank you. Mr. Chairman and members of the committee, I am Aves Thompson, Executive Director of the Alaska Trucking Association. The Alaska Trucking Association is a state wide organization representing trucking interests from Barrow to Ketchikan for more than 49 years. Our more than 200 members represent all of the diverse trucking operations in the state and many associate members who provide goods and services to our industry. On behalf of ATA, I thank you for the opportunity to testify on the subject of AGIA.

The highest priority of the Alaska Trucking Association is to get a gas line built, up and running and delivering Alaska's gas to market. We applaud the Governor and her team for promptly presenting AGIA to the legislature for their consideration.

We believe like others, that AGIA has a chance to bring a gas line to fruition. We also believe that certain changes must be made to make the gas line a reality. I will address some of the important issues as we see them.

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- Bid requirements of the bill are far too specific. The better approach may be to set performance specifications or expectations or outcomes and let the bidders address how they will meet those expected outcomes. There may be other ways to reach these mutually beneficial outcomes, and the prescriptive nature of the current bill guarantees we will never hear the alternatives.

- The bill needs clear and objective criteria for evaluating applications. Some recommendations for criteria are:
  - Best financial return to the state,
  - Lowest level of risk of delays due to lawsuits, etc,
  - Highest probability of success,
  - Jobs, instate use of gas, etc.
  - Expansion provisions for adding gas to the line.

- The bill places too much emphasis on mitigating the short-term financial risks incurred by the pipeline builder and too little to address the much longer-term and greater risks of gas shippers. Fiscal certainty is an important issue for those that will be asked to commit to long term firm transportation agreements worth billions of dollars over the life of the agreements.

These are a few of our concerns and I'm sure you will hear from others today as they share their testimony. The Alaska Trucking Association is eager for this project to succeed and stands ready to assist in any way to help make this dream a reality. Thank you for your time.

- Position on the Alaska Gasline Inducement Act -

HOUSE [redacted] Bill [redacted] 177

5-May-07

My name is Maynard Tapp and I worked in Alaska since 1972, I am a citizen of Alaska since 1990 and Alaskan in spirit since 1954 when my dad worked for the U.S. Coast Guard in Barrow.

HOW TO DO THE DEAL NOW

1. Take the existing AGIA add what was learned by the legislature in the previous 3 years. I am not suggesting re-visiting the Stranded Gas Act.
2. Pass AGIA
3. Begin Negotiations with Qualified Candidates according to the following:-
   a. In an open and transparent process, and in line with current AK State Procurement Policies, create a weighted evaluation system that will fairly judge the proposals prior to award that will be available for public scrutiny.
   b. Require performance bonds from all participants that are willing to spend $500 million on a Feasibility Study (approx 2% of total estimated cost).
4. Award the $500 million based on a successful "Open Season"
5. Ask yourselves this question. "Are we better off with an inflexible former governor, or a currently inflexible commissioner?"

Remember, every day we delay the gas line –

- The state of Alaska loses $4.2 million dollars.
- North Slope production and related state revenues decline at 6% per year.
- Competing projects and technologies around the world are not waiting for Alaska.

Do you want the federal government to take over the project?

State of Alaska Goals are; 1. Bring more oil to market; 2. Bring Gas to Market; and 3. Collect revenues for Alaskans.

CONCLUSION:
BE LEADERS for the sake of Alaska. Make AGIA your own. Pass AGIA. Work the details with the Administration.

Thank-you for the opportunity to speak to your committee.

ALASKA SUPPORT INDUSTRY ALLIANCE HOUSE FINANCE TESTIMONY ON HOUSE BILL 177

May 5, 2007

Thank you, Chairman Chenault & members of the House Finance Committee. I'm Paul Laird, and I'm general manager of the Alaska Support Industry Alliance.

Our member companies provide the goods & services that make Alaska's oil, gas & mining industries possible. Their futures, like the futures of all Alaskans, depend on a North Slope gas project.

This bill, as currently drafted, won't get us one.

Some of you and many of your colleagues in the legislature privately acknowledge that the Alaska Gasline Inducement Act is flawed ... that it's more likely to induce years of disappointments & disputes than a gas line.

You've heard the arguments, you know the problems. I won't belabor them, and for that, you're welcome.

But on behalf of our 400+ members, their 30,000+ Alaska employees and everyone who depends on a strong Alaska economy for the long term, I urge you to fix them now.

Terms of the bill dictate that you may not get a second chance for many years, and by then, it may be too late.

We salute the efforts of some of you to induce compromise between two seemingly immovable forces - a popular governor with a plan that probably won't work and powerful North Slope producers with proposals that appear politically unpalatable.

Yes, we get it.

We salute your efforts to craft a bill that can achieve its objective.

We will support you when you make the tough decisions that will be required if this bill is to succeed.

Thank you.

NORTHWEST TECHNICAL SERVICES

Testimony regarding House Bill 177
May 5, 2007
By
Mary E. Shields, General Manager
Northwest Technical Services

Chairmen Chenault and Meyer, members of the House Finance Committee:

Good afternoon. My name is Mary Shields and I am the General Manager of Northwest Technical Services. We employ over 100 people in Alaska, most of whom work in the oil industry.

As a long time Alaskan (since 1972) and an active participant in many areas of Alaskan life, I appreciate your scrutiny and close examination of the bill as posited by the Governor.

As we are all aware, certainly you more than anyone else, it is the responsibility of the Legislature to foster an investment and development climate that will add value to our state resources and encourage participation in this enormous project. I am concerned that in the Governor's desire to be fair to all, we now have a bid process which does not contain the clear and objective criteria for the evaluation of applications which I would anticipate in any bid process. I am also concerned that providing a $500 million incentive would encourage those without the financial strength to carry through with a project of this size. Most RFPs (or, in this case an RFA) to which I have responded require that Northwest Technical Services show proof that we have the financial wherewithal to pay our employees and are very specific that any expenses incurred during the course of the bid are not reimbursable. As a prudent business person, I would expect the State of Alaska to make the same requirement – we shouldn't pay any company to bid.

I also have to concur with previous testimony that points out that the State of Alaska has a disastrous record of selecting project winners. The selection of this Licensee needs to follow a formalized, logical objective course. Any subjectivity in selection needs to be eliminated.

We all talk about making sure that we have jobs for our children and grandchildren in the future. They are the ones who will continue to make Alaska prosperous. With the continual decrease in oil production to keep TAPS filled, with the sure loss of positions

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NORTHWEST TECHNICAL SERVICES

and dollars to the state's coffers as this happens, it is imperative that we do not fail in getting an acceptable bid process in place – preferably prior to the end of the first half of this legislative session. We've all seen the charts.

I thank you for your time. I know that you want to do what is best for the state of Alaska and for its future generations. I ask that you make certain that HB 177 accomplishes that mission.

Kind regards,

Mary E. Shields
General Manager

4401 Business Park Boulevard, Bldg N, Ste 26 • Anchorage, AK 99503-4580 • 907 562-1633 • 907 562-5875 fax
E-Mail: ak@pdstech.com • Website: www.NWTS-ak.com

My name is Joey Merrick, I'm from Eagle River and I'm also the Business Manager of Laborers' Local 341. We represent over 2100 members in south central Alaska comprised of Pipeline, Building Trades, Heavy and Highway workers. Thank you for working through the weekend to allow public testimony on HB 177.

We want to be sure that we are on record in support of a gas project as it is vital to Alaska's Economy. We appreciate the Administrations and the Legislators efforts to bring our gas to market and to put Alaskan's to work.

I appreciate the time the legislators are putting in on this very important Bill. Thanks for taking the time to meet with me over the last couple of days in Juneau as I know how busy you are at this time of the session. I hope I was able to show those of you who met with me that the only way to guarantee that Alaskans get to work first is through a project labor agreement.

There are many aspects of AGIA, but the issue that is the most important for the people that I represent, is putting the Alaskan people to work.

The best way to do that is with a Project Labor Agreement. It is a way that you can guarantee that Alaskan workers will be dispatched through Alaskan Hiring Halls and Alaskan Apprentices will be afforded opportunities to learn their craft and to keep their wages and benefits in Alaska to help maintain the economy.

Only through a Project Labor Agreement can we make sure that Alaska Native Hire will take place and we can help the growing unemployment rates in the Rural Villages.

We would encourage you to make sure that a Project Labor Agreement will stay in the AGIA to be sure that the Alaska Workers are able to take advantage of the Biggest Project in the states history and that Alaskans can help develop our gas.

Thank you for allowing me to speak on behalf of the Laborers Local 341 on HB177 and once again thank you for the work you are doing to bring our gas to market.

a. j. Merrick

5-5-07

NOTES 4-30-07 AGIA TESTIMONY for the Record
TO: Govenor, Attorney General, Legislature, and the Citizens of Alaska
FROM: Paul D. Kendall -- 907-222-7882
REF: ALASKAS FUTURE – 8 Point Plan
I really think we need to outline an immediate business plan for a vision for Alaskas future...

I FIRMLY BELIEVE THAT ALL OF THE PROJECTS LISTED BELOW NEED TO BEGIN RIGHT AWAY WITH ALL DO HASTE !

PROJECTS TO UNDERTAKE: at the same time

1. Canadian Gas Line Project

2. Alaskan / American Sovereign Line to Valdez for Export and Alaskan economic infrastructure

3. Single Family Home and Residential "Energy Bill of Rights" (4 areas)

4. Village and Community Hydrogen Gas Fuel Conversion, Production and Implementation—One project per Major City area- + =# of lone villages

5. ANWAR Opening for the Purpose of Hydrogen Production, Storage, R & D for Alaska and for National Security Purposes..

6. The locating, relocating, and facilitating the legislature to full time to the Anchorage area for 9 months of the year –
Salary for full time representatives—
Extending all elected positions to min 4 years of service in office,
A 24 / 7 Alaska channel + use it as a political campaign channel

7. Very large Renewable Energy Applications Plan (no Fossil Fuels)

8. Permanent Fund Review – into land and new world energy technologies

If you tease, detail, grow, and initiate the above projects out;
Expand by subdividing into needs of each of the above projects
you will see a tramendous potential future.... HUGE !

But; Are we able to handle all of these at the same time ??

I want to be our HYDROGEN MANAGER / COMMISSIONER !! Please!

IN CLOSING__ Paul D. Kendall ---- 907-222-7882
----------END----------date 4-30-07-------

5-3-07
TO: Govenor, Atty Gen, Legislature and the people of Alaska
FROM: Paul D. Kendall
907-?22-7882

AGIA NOTES::TESTIMONY

Yesterday, or rather early this am i sent you all an email titled Historical moments".. containing suggestions!
Just some filler—

The 3BNPs (3 big non-producers) have organized (those big downtown buildings ar full of staff) and you need to also, if you have to create new committees to take testimony on other things that i think are relevant to AGIA – which i know you probably dissagree..

Look, you have gotten into something that is going to require your full time to do right – and this is worth a lot of $$ and history

Look – ENERGY HAS BECOME HUGE--it is one of the four elements necessary for us to live as a viable society—sorry history tagged you guys to lead us to our new society; But if you want to quit; call me, i will take your place ! ha ha,

HEARINGS ON:

-Energy "Bill of Rights for Single Family home owners"
-Steel producers,
-California and western coastal states energy needs,
-Hydro-carbons definition,
-well head gas price $3.56 p/mcf definitions,
-Oilfield leases in reference to taking out gas by us Alaskans now!,
-Oilfield leases in references to changing all leases now for future use.,
-Hydrogen Gas in all fields,
-ANWAR opening for hydrogen gas development,
-What are Hydrates –HUGE Discovery ?
-Gas Treatment Plant,
-Refinery,
-Ships shipping LNG,
-What is BTU & JULES,
-How Plastics and Hdrogen are made from natural gas in a refinery,
-What is coal gasification?
-Power Line Transmission developers
-What is happening in DUBAI, QATAR, SAUDIA ARABIA,
-Why is Saudia Arabia saying they will supply 25 % of worlds need for -

Hydrogen?,
-Meet the End users of Gas-big boys, industrial, states cities utilities
-Permanent Fund direction of investment
-Rail road bonding capacity 18 billion dollars
-What role, use, % of energy -- the Single familly home plays in using –gas, electric, water, gasoline -

----------24----
TOTAL to date = _____PRIORITY of Hearings_____

Please consider the following:

1. Need to see a discussion and understanding of how $3.56 per MCF at the well head is figured...

2. HYDRO-CARBONS—What specifically are they ?
Where do they come from (oil and gas only)
How do they interact? What do they make?
how big are they to each other?

3.********* Should we consider taxing by the Molecules ? BTUs ? or Jules ?
?? and or Carbon releases ? I am serious about learning on this **********

4....Please stop using the term F.T. ! Its use should be for inside traders only! You must use the description it represents – even if its over and over again --- F.T. disconnects the viewing public because its too big of a term to be attached to F.T. use....the 3NPs know that too...

5. Someone was just telling me that the 3BNPs were shipping gas all along with the oil and were generating other revenus outside the agreed to terms and they were under suit for perhaps a lot of money for doing so—we had better look at the gas processing, or treatment plant or direct outputs closely to see if gas was stripped of something of value ?

Thank You,

Respectfully and Sincerely,

Paul D. Kendall
907-222-7882

----------END----------

Historical moments 5-2-07
AGIA TESTIMONY
Paul D. Kendall

5-2-07

Ladies and Gentlemen,

I have been very busy as a citizen-- but now, off work and ready to help in any way i can..
If you all were here,. We could cut your lawn for you, or go fer you lunch or donate some money to you so you could "stay in the frey" and so on - so to speak...

Look, I (and i really think WE) see what is going on! Its a coordinated squeeze from two or more fronts or flanks and directions..
If I may talk openly; They have you sequestered in Juneau; Isolated and unnaccessable to the rest of us, away from your homes, where your families rest, rewind, reconstruct, and support each other ..
Maybe i am wrong about being sequestered in Juneau; But i don't think so. History reflects that Shangrila can be a cell, compound or prison also..
Every Major Event in History shows or tells of Equal amounts of courage or strength that have to be willed up to equal an unjust act or event....

By now, you must see, they have mustered their people/staffs/consultants/lobbyist, associates, connections and insiders!
(and there is always insiders-that is why you are in the public and have to stay there; it is your safety and foundation)

THEY HAVE A PLAN--I THEY ARE SERIOUS ABOUT WHATEVER IT IS THEY ARE DOING!
YOU MUST PREPARE EQUALLY—

Look, find a calm place and reflect; You will see the NON-Producers (Burkes' Term) have a game plan. Its coordinated, Methodical, Rehersed, Discussed, Its been role-played...And;
Its too good not to be!

1. They have captured equal camera and public time; This is being coordinated.

2. By them occupying space and time – Then they win because no one else can fill that space with enlightening or unexpected testimony - or you guys can't rest –
(Some times you lose but win by occupying the time,space, or presence which could be something unplanned for. Its usually a weighted judgement call)

3.They have confused the possible competition in several ways; "You seek to create uncertainty amongst your bidders" Conoco Phillips 5-? 07

4. Their determination to keep you without clear insight or indications as to what to do is because they continue to lure you with greed, fear, worry, uncertainty,; They are in essence trying to force you to "collapse in on yourselves"!

5.
We all send each other signals in many and rapid ways. Little conveyances via facial, body, sounds, looks that tell the other its ok, i am with you on this,etc. or,I am uncertain.. These signals are usually verybrief, honest,clear, well meant and subtle in nature.

But when you have some one who is willing to wedge in between those fundamental moments of conveyances we give teach other –so as to-- mimic those signals but not be sincere; It is such a fundamental betrayal of our subtle, minumal values of unexpressed and unquestioned honest
60 signaling;
That it is very difficult to see! –

THAT is why they always start out with the " WE REALLY WANT THIS-- BIG MONEY ---They are lying or at least not being open and partnering with you as us the people..

66 It is sir and Mams very, very concerning. It is such a betrayal of such miminmal fundamental vaues we give to each other.. This is not a good sign.

if a car or life insurance man came to your door and tried to sell you a policy and acted this way you would ask him and his associate to leave with him..ya know?
And you know why you would do this? Because there is no FATIGUE, GREED or FEAR
72 involved in your decision reasoning

6....They will, if not are now, trying to divide you one at a time.

I cannot convey to you in strong enough terms; I am not sure what the producers are up to; Until you find out you must be prepared to make history at your will; That means in
78 my opinion you must do the following with the Governor participation

1.....Go meet and talk it out.. –DECLARATION OF

" A STATE OF UNUSUAL AFFAIRS"

84 2.....Place yourselves into a temperary salaried status,

3.....Place yourselves into an ongoing state of
" CONTINOUS IN SESSION- YEAR ROUND"
with needs for "vacation or temporary sessation of business"

90 4...establish an ending date for the SESSION IN JUNEAU AND
"RECONVENING IN ANCHORAGE AND/OR FAIRBANKS"

5.....Maintain AGIA schedual of needs as per Govenor and Team

6..... Do not get spooked! These are simply times of an unusual "state of affairs"
96 Get a little R&R with your families while your special assignment team sets up your next hearing, cams, and location, etc.!
Important- you do not task your Juneau team or critical mass team that is taking care of everyday business—you can backwash with disruption and workloads if not careful.

7.....Quit calling all the NON producers' buddies and associaltes (FERC- DOE- PUC)
102 And no more telephone interviews !
Those are just stupid on stupid – you lose and we lose – Ya gotta see a mans eyes and face... You do not want to lose your citizens feeling included in this process.

8. ....You cannot let the non producers drive you! (isolated, detached from familly, travel, fatigue, schedualing, you are being uploaded and down loaded at a hell of a clip here. etc.) the non producers will disassemble you if you let them – you and we all have limitations...Get with the Gov..

9.....Calm, Self Esteem, Relaxed, Patient, Rename and Review "Our Alaskan /American Gas line"--- Talk to California,, Look at WELL HEAD PRICING (the well head pricing I think will make them nervous) DO A HYDROGEN BREAK-FUN LEARN HOW ABOUT A BIG STEEL MANUFACTURER- --NPs probably own them too.

10. I strongly suggest you do not allow any more meetings ON OR OFF CAMERA, OFFICIAL OR UNOFFICIAL with the NON PRODUCERS UNTIL FURTHER NOTICE ! (perhaps, ?? only secure runners)

The NON producers will look to use your request from you "to get back to them in writing" to come back into the picture ! Do not allow this – they will press the issue and entise you with going to give you something-- bullshit .

They can send it over with runner or on secure line. "You people need a little off the burner time".

If I read this right, the non – producers must maintain the full court press and that has certain needs to work – They cannot back off now that the full court press is building !!

You must not allow them to do public cameras again—Unless they are sworn in by a judge and prepared to give official dialogue –

This meandering , evasive, wiggling, wavering, crippled, tortured, twisted, convuluted, knotted, wrinkled, greed titilated, condescending, anti-american, anti-alaskan, cowardly, kaniving, kind bullying, Enron dialogue, of non answered and high school chess like crap is over..

Sometimes in life you have to accept the lot you got or life gives ya; and if it's a battle they want, well, -- If the NPs don't straighten up we gonna send our governor on every commercial and talk shows all across AMERICA—Yea, that should scare the hell out of em...eh humor.. But, I'll bet she could do it!

Sorry about the long letter—I know your busy—Come on, We love big crap!
Inspire us your pepople! This is Alaska!
The *3NPs are all Texans. (Aren't they?)
Do the declaration, money, session and meets thing! Nobody corners or surrounds ya dudes – It's a serrengetti thing!

Paul D. Kendall
907-222-7882

* 3NPs – Check it out ! the"3 Non Producers" Is that neat or what ? Yea, see I just invented – well, me and Eddy Burke; He made up the Non Producers,, I just fashioned it I guess !

----------END----------5-2-07----------

DOWLAND—BACH

WWW.DOWLANDBACH.COM

P.O. BOX 230126
ANCHORAGE, ALASKA 99523-0126
(907) 562-5818

RE: House Finance Committee Testimony (HB 177) May 5, 2007

Good afternoon Chairmen Chenault and Meyer, Co-Chair Stoltze and other esteemed and distinguished members of the House Finance Committee. My name is Lynn Johnson and as most of you know, I am the President and co-founder of Dowland-Bach Corporation and a past President of the Alaska Support Industry Alliance. First of all, I would like to thank you all for all of your diligent and thoughtful work to date on AGIA and HB 177. I suspect that you all have had numerous visits, e-mails and phone calls recently on this subject. The reason for all of this fuss is that Alaska needs to get going on a gas project now, not later. It appears to me that we are now farther away than ever from passing any legislation enabling construction of our natural gas pipeline to the lower 48. The three major players now say that they are not even going to bother to submit a bid and apply for a state license to build the North Slope gas pipeline. Without their participation, the probability of Alaska ever getting a gas pipeline is close to zero. We were much closer to a pipeline twelve months ago and it seems to be getting worse by the day.

As a businessman doing business with the producers, I obviously have empathy for their position, but this anti-big oil rhetoric has got to stop. Taxes on the oil portion of their current business provide 88% of our current state revenue and have done so for years, and this is how we treat them?? We need to make key changes to this bill prior to passage, including ones that include eliminating exclusivity and replacing prescriptive mandates with objectives.

In summary, if businesses such as mine are going survive, we all need to encourage the building of a gas pipeline in the near term by those capable of doing it. AGIA may well be the last chance at having this construction actually take place, and if we fiddle around for another five or six years, some other gas from another basin is going to fill the need in the Mid-West and Alaska gas will no longer be in such high demand. Let's fix AGIA and then pass it by ensuring that it addresses the needs of Alaskans, of the developer and transporter and of North Slope producers and shippers. It's Time. Thanks

DOWLAND—BACH

LYNN C. JOHNSON
PRESIDENT

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Testimony regarding House Bill 177
May 5, 2007
By
Kelly Patrick, Alaska State Resident

Co-Chairmen Chenault and Meyer's, members of the House Finance Committee:

Good afternoon, my name is Kelly Patrick. As a long time Alaskan and an active participant in the community and public affairs, I appreciate your scrutiny and close examination of the bill as drafted by the Governor.

Oil revenue currently accounts for 90 percent of the states budget. Alaska North Slope oil production is decreasing and will continue to do so with the States budget situation becoming critical well before 2016. Certainly the House more than anyone understands the need to move swiftly and decisively towards replacing our oil based economy with a more diversified economy based on natural gas.

I am concerned that in the Governor's desire to be fair to all, we now have a bid process that does not contain the clear and objective criteria for the evaluation of applications that I would anticipate in any bid process. I am also concerned that providing a $500 million incentive would encourage those without the financial strength to carry through with a project of this size. Most RFPs (or, in this case an RFA) that the normal business community contractors respond to have to show proof they have the financial wherewithal to pay their employees and are very specific that any expenses incurred during the course of the bid are not reimbursable. As a prudent business person, I would expect the State of Alaska to make the same requirement.

I also have to concur with previous testimony that points out that the State of Alaska needs to improve their internal processes in selecting project winners in an effort to reach a more productive and beneficial outcome for the people of the State of Alaska. The selection of this Licensee needs to follow a formalized, logical objective course. Any subjectivity in selection needs to be eliminated.

We all talk about making sure that we have future jobs for our children and grandchildren, as they are the ones who will continue to make Alaska prosperous. With the continual decrease in oil production to keep TAPS filled, it is imperative that we do not fail in getting an acceptable bid process in place preferably prior to the end of the first half of this legislative session.

I thank you for your time. I know that you want to do what is best for the State of Alaska and for its future generations. I ask that you make certain that HB 177 accomplishes that mission.

Kind regards,

Kelly Patrick

UDELHOVEN

Oilfield System Services, Incorporated

184 East 53rd Avenue
Anchorage, Alaska 99518-1222
(907) 344-1577 Fax (907) 522-2541

Mr. Chairman, members of the committee.

Thank you for the opportunity to testify on the AGIA Bill. My name is Jim Gilbert, and I'm President and testifying on behalf of my company, Udelhoven Oilfield System Services.

Our 400-plus employees provide technical expertise to the oil and gas industry in Alaska, the Gulf of Mexico, Tbilisi, Georgia and Bohai Bay, China.

First and foremost, we want a gas project ... sooner rather than later, and with the greatest long-term benefits for the State of Alaska, Alaskan workers, Alaskan businesses and all Alaskans. North Slope gas commercialization holds the key to Alaska's future.

We understand the importance and urgency of transforming our gas potential into a gas project. The opportunity to market our gas won't last indefinitely, and there's a very real risk of losing it altogether if we don't act quickly.

Agia needs fixing, listen to the producers and follow their lead

Both the state and shippers need to be involved in and have oversight of a project execution plan that provides the greatest netbacks at the wellhead. A third-party pipeline builder with no production interests will have no incentive to reduce costs and no ability to "guarantee" the tariff in advance

The Alaska Gasline Inducement Act may be our last and best chance to make a North Slope gas project a reality, but only if it's fixed before it's passed. In order to succeed, the bill must acknowledge the interests of Alaskans, and of North Slope producers and shippers.

Thank you

Jim Gilbert
184 E. 53rd Ave
Anchorage, AK.

Alaska Trucking Association, Inc.
3443 Minnesota Drive · Anchorage, Alaska 99503 · Phone (907) 276-1149 · Fax (907) 274-1946
www.aktrucks.org

Aves Thompson, Executive Director
Alaska Trucking Association
House Finance Testimony, HB177
Saturday, May 5, 2007

Thank you. Mr. Chairman and members of the committee, I am Aves Thompson, Executive Director of the Alaska Trucking Association. The Alaska Trucking Association is a state wide organization representing trucking interests from Barrow to Ketchikan for more than 49 years. Our more than 200 members represent all of the diverse trucking operations in the state and many associate members who provide goods and services to our industry. On behalf of ATA, I thank you for the opportunity to testify on the subject of AGIA.

The highest priority of the Alaska Trucking Association is to get a gas line built, up and running and delivering Alaska's gas to market. We applaud the Governor and her team for promptly presenting AGIA to the legislature for their consideration.

We believe like others, that AGIA has a chance to bring a gas line to fruition. We also believe that certain changes must be made to make the gas line a reality. I will address some of the important issues as we see them.

Alaska Trucking Association, Inc.
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www.aktrucks.org

- Bid requirements of the bill are far too specific. The better approach may be to set performance specifications or expectations or outcomes and let the bidders address how they will meet those expected outcomes. There may be other ways to reach these mutually beneficial outcomes, and the prescriptive nature of the current bill guarantees we will never hear the alternatives.

- The bill needs clear and objective criteria for evaluating applications. Some recommendations for criteria are:
  - Best financial return to the state,
  - Lowest level of risk of delays due to lawsuits, etc,
  - Highest probability of success,
  - Jobs, instate use of gas, etc.
  - Expansion provisions for adding gas to the line.

- The bill places too much emphasis on mitigating the short-term financial risks incurred by the pipeline builder and too little to address the much longer-term and greater risks of gas shippers. Fiscal certainty is an important issue for those that will be asked to commit to long term firm transportation agreements worth billions of dollars over the life of the agreements.

These are a few of our concerns and I'm sure you will hear from others today as they share their testimony. The Alaska Trucking Association is eager for this project to succeed and stands ready to assist in any way to help make this dream a reality. Thank you for your time.

- Position on the Alaska Gasline Inducement Act -

HOUSE [redacted]e Bill [redacted] 177

5-May-07

My name is Maynard Tapp and I worked in Alaska since 1972, I am a citizen of Alaska since 1990 and Alaskan in spirit since 1954 when my dad worked for the U.S. Coast Guard in Barrow.

HOW TO DO THE DEAL NOW

1. Take the existing AGIA add what was learned by the legislature in the previous 3 years. I am not suggesting re-visiting the Stranded Gas Act.
2. Pass AGIA
3. Begin Negotiations with Qualified Candidates according to the following:-
   a. In an open and transparent process, and in line with current AK State Procurement Policies, create a weighted evaluation system that will fairly judge the proposals prior to award that will be available for public scrutiny.
   b. Require performance bonds from all participants that are willing to spend $500 million on a Feasibility Study (approx 2% of total estimated cost).
4. Award the $500 million based on a successful "Open Season"
5. Ask yourselves this question. "Are we better off with an inflexible former governor, or a currently inflexible commissioner?"

Remember, every day we delay the gas line –

- The state of Alaska loses $4.2 million dollars.
- North Slope production and related state revenues decline at 6% per year.
- Competing projects and technologies around the world are not waiting for Alaska.

Do you want the federal government to take over the project?

State of Alaska Goals are; 1. Bring more oil to market; 2. Bring Gas to Market; and 3. Collect revenues for Alaskans.

CONCLUSION:

BE LEADERS for the sake of Alaska. Make AGIA your own. Pass AGIA. Work the details with the Administration.

Thank-you for the opportunity to speak to your committee.

ALASKA SUPPORT INDUSTRY ALLIANCE HOUSE FINANCE TESTIMONY ON HOUSE BILL 177

May 5, 2007

Thank you, Chairman Chenault & members of the House Finance Committee. I'm Paul Laird, and I'm general manager of the Alaska Support Industry Alliance.

Our member companies provide the goods & services that make Alaska's oil, gas & mining industries possible. Their futures, like the futures of all Alaskans, depend on a North Slope gas project.

This bill, as currently drafted, won't get us one.

Some of you and many of your colleagues in the legislature privately acknowledge that the Alaska Gasline Inducement Act is flawed ... that it's more likely to induce years of disappointments & disputes than a gas line.

You've heard the arguments, you know the problems. I won't belabor them, and for that, you're welcome.

But on behalf of our 400+ members, their 30,000+ Alaska employees and everyone who depends on a strong Alaska economy for the long term, I urge you to fix them now.

Terms of the bill dictate that you may not get a second chance for many years, and by then, it may be too late.

We salute the efforts of some of you to induce compromise between two seemingly immovable forces - a popular governor with a plan that probably won't work and powerful North Slope producers with proposals that appear politically unpalatable.

Yes, we get it.

We salute your efforts to craft a bill that can achieve its objective.

We will support you when you make the tough decisions that will be required if this bill is to succeed.

Thank you.

NORTHWEST TECHNICAL SERVICES

Test .ony regarding House Bill 177
May 5, 2007
By
Mary E. Shields, General Manager
Northwest Technical Services

Chairmen Chenault and Meyer, members of the House Finance Committee:

Good afternoon. My name is Mary Shields and I am the General Manager of Northwest Technical Services. We employ over 100 people in Alaska, most of whom work in the oil industry.

As a long time Alaskan (since 1972) and an active participant in many areas of Alaskan life, I appreciate your scrutiny and close examination of the bill as posited by the Governor.

As we are all aware, certainly you more than anyone else, it is the responsibility of the Legislature to foster an investment and development climate that will add value to our state resources and encourage participation in this enormous project. I am concerned that in the Governor's desire to be fair to all, we now have a bid process which does not contain the clear and objective criteria for the evaluation of applications which I would anticipate in any bid process. I am also concerned that providing a $500 million incentive would encourage those without the financial strength to carry through with a project of this size. Most RFPs (or, in this case an RFA) to which I have responded require that Northwest Technical Services show proof that we have the financial wherewithal to pay our employees and are very specific that any expenses incurred during the course of the bid are not reimbursable. As a prudent business person, I would expect the State of Alaska to make the same requirement – we shouldn't pay any company to bid.

I also have to concur with previous testimony that points out that the State of Alaska has a disastrous record of selecting project winners. The selection of this Licensee needs to follow a formalized, logical objective course. Any subjectivity in selection needs to be eliminated.

We all talk about making sure that we have jobs for our children and grandchildren in the future. They are the ones who will continue to make Alaska prosperous. With the continual decrease in oil production to keep TAPS filled, with the sure loss of positions

4401 Business Park Boulevard, Bldg N, Ste 26 • Anchorage, AK 99503-4580 • 907 562-1633 • 907 562-5875 fax
E-Mail: ak@pdstech.com • Website: www.NWTS-ak.com

NORTHWEST TECHNICAL SERVICES

and dollars to the state's coffers as this happens, it is imperative that we do not fail in getting an acceptable bid process in place – preferably prior to the end of the first half of this legislative session. We've all seen the charts.

I thank you for your time. I know that you want to do what is best for the state of Alaska and for its future generations. I ask that you make certain that HB 177 accomplishes that mission.

Kind regards,

Mary E. Shields
General Manager

4401 Business Park Boulevard, Bldg N, Ste 26 , Anchorage, AK 99503-4580 , 907 562-1633 , 907 562-5875 fax
E-Mail: ak@pdstech.com , Website: www.NWTS-ak.com

My name is Joey Merrick. I'm from Eagle River and I'm also the Business Manager of Laborers' Local 341. We represent over 2100 members in south central Alaska comprised of Pipeline, Building Trades. Heavy and Highway workers. Thank you for working through the weekend to allow public testimony on HB 177.

We want to be sure that we are on record in support of a gas project as it is vital to Alaska's Economy. We appreciate the Administrations and the Legislators efforts to bring our gas to market and to put Alaskan's to work.

I appreciate the time the legislators are putting in on this very important Bill. Thanks for taking the time to meet with me over the last couple of days in Juneau as I know how busy you are at this time of the session. I hope I was able to show those of you who met with me that the only way to guarantee that Alaskans get to work first is through a project labor agreement.

There are many aspects of AGIA, but the issue that is the most important for the people that I represent, is putting the Alaskan people to work.

The best way to do that is with a Project Labor Agreement. It is a way that you can guarantee that Alaskan workers will be dispatched through Alaskan Hiring Halls and Alaskan Apprentices will be afforded opportunities to learn their craft and to keep their wages and benefits in Alaska to help maintain the economy.

Only through a Project Labor Agreement can we make sure that Alaska Native Hire will take place and we can help the growing unemployment rates in the Rural Villages.

We would encourage you to make sure that a Project Labor Agreement will stay in the AGIA to be sure that the Alaska Workers are able to take advantage of the Biggest Project in the states history and that Alaskans can help develop our gas.

Thank you for allowing me to speak on behalf of the Laborers Local 341 on HB177 and once again thank you for the work you are doing to bring our gas to market.

a. J. Merrick

5-5-07

NOTES 4-30-07 AGIA TESTIMONY for the Record
TO: Govenor, Attorney General, Legislature, and the Citizens of Alaska
FROM: Paul D. Kendall -- 907-222-7882
REF: ALASKAS FUTURE – 8 Point Plan
I really think we need to outline an immediate business plan for a vision for Alaskas future...

I FIRMLY BELIEVE THAT ALL OF THE PROJECTS LISTED BELOW NEED TO BEGIN RIGHT AWAY WITH ALL DO HASTE !

PROJECTS TO UNDERTAKE: at the same time

1. Canadian Gas Line Project

2. Alaskan / American Sovereign Line to Valdez for Export and Alaskan economic infrastructure

3. Single Family Home and Residential "Energy Bill of Rights" (4 areas)

4. Village and Community Hydrogen Gas Fuel Conversion, Production and Implementation—One project per Major City area- + =# of lone villages

5. ANWAR Opening for the Purpose of Hydrogen Production, Storage, R & D for Alaska and for National Security Purposes..

6. The locating, relocating, and facilitating the legislature to full time to the Anchorage area for 9 months of the year –
   Salary for full time representatives—
   Extending all elected positions to min 4 years of service in office,
   A 24 / 7 Alaska channel + use it as a political campaign channel

7. Very large Renewable Energy Applications Plan (no Fossil Fuels)

8. Permanent Fund Review – into land and new world energy technologies

If you tease, detail, grow, and initiate the above projects out;
Expand by subdividing into needs of each of the above projects
you will see a tramendous potential future.... HUGE !

But; Are we able to handle all of these at the same time ??

I want to be our HYDROGEN MANAGER / COMMISSIONER !! Please!

IN CLOSING__ Paul D. Kendall ---- 907-222-7882
----------END----------date 4-30-07-------

5-3-07
TO: Govenor, Atty Gen, Legislature and the people of Alaska
FROM: Paul D. Kendall
907-222-7882

AGIA NOTES::TESTIMONY

Yesterday, or rather early this am i sent you all an email titled Historical moments".. containing suggestions!
Just some filler—

The 3BNPs (3 big non-producers) have organized (those big downtown buildings ar full of staff) and you need to also, if you have to create new committees to take testimony on other things that i think are relevant to AGIA – which i know you probably dissagree..

Look, you have gotten into something that is going to require your full time to do right – and this is worth a lot of $$ and history

Look – ENERGY HAS BECOME HUGE—it is one of the four elements necessary for us to live as a viable society—sorry history tagged you guys to lead us to our new society; But if you want to quit; call me, i will take your place ! ha ha,

HEARINGS ON:

-Energy "Bill of RIghts for Single Family home owners"
-Steel producers,
-California and western coastal states energy needs,
-Hydro-carbons definition,
-well head gas price $3.56 p/mcf definitions,
-Oilfield leases in reference to taking out gas by us Alaskans now!,
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-Power Line Transmission developers
-What is happening in DUBAI, QATAR, SAUDIA ARABIA,
-Why is Saudia Arabia saying they will supply 25 % of worlds need for -

Hydrogen?,

-Meet the End users of Gas-big boys, industrial, states cities utilities

-Perm:.nent Fund direction of investment

-Rail road bonding capacity 18 billion dollars

-What role, use, % of energy -- the Single familly home plays in using –gas, electric, water, gasoline -

--------------------------------24----

TOTAL to date = ___________PRIORITY of Hearings____________

[[[

Please consider the following:

1. Need 'o see a discussion and understanding of how $3.56 per MCF at the well head is figured...

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how big are they to each other?

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Thank You,

Respectfully and Sincerely,

Paul D. Kendall
907-222-7882

---END---

Historical moments 5-2-07
AGIA TESTIMONY
Paul D. Kendall

5-2-07

Ladies and Gentlemen,

I have been very busy as a citizen-- but now, off work and ready to help in any way i can..
If you all were here.. We could cut your lawn for you, or go fer you lunch or donate some money to you so you could "stay in the frey" and so on - so to speak...

Look, I (and i really think WE) see what is going on! Its a coordinated squeeze from two or more fronts or flanks and directions..
If I may talk openly, They have you sequestered in Juneau; Isolated and unnaccessable to the rest of us, away from your homes, where your families rest, rewind, reconstruct, and support each other...
Maybe i am wrong about being sequestered in Juneau, But i don't think so. History reflects that Shangrila can be a cell, compound or prison also..
Every Major Event in History shows or tells of Equal amounts of courage or strength that have to be willed up to equal an unjust act or event ...

By now, you must see, they have mustered their people/staffs/consultants/lobbyist, associates, connections and insiders!
(and there is always insiders-that is why you are in the public and have to stay there, it is your safety and foundation)

THEY HAVE A PLAN--! THEY ARE SERIOUS ABOUT WHATEVER IT IS THEY ARE DOING!
YOU MUST PREPARE EQUALLY—

Look, find a calm place and reflect; You will see the NON-Producers (Burkes' Term) have a game plan. Its coordinated, Methodical, Rehersed, Discussed, Its been role-played...And,
Its too good not to be!

1. They have captured equal cam[illegible] and public time. This is being coordinated

2. By them occupying space and time -- Then they win because no one else can fill that space with enlightening or unexpected testimony - or you guys can't rest –
(Some times you lose but win by occupying the time,space, or presence which could be something unplanned for. Its usually a weighted judgement call)

3 They have confused the possible competition in several ways; "You seek to create uncertainty amongst your bidders" Conoco Phillips 5-2-07

4. Their determination to keep you without clear insight or indications as to what to do is because they continue to lure you with greed, fear, worry, uncertainty,. They are in essence trying to force you to "collapse in on yourselves"!

5.
We all send each other signals in many and rapid ways. Little conveyances via facial, body, sounds, looks that tell the other its ok, i am with you on this,etc, or,i am uncertain . These signals are usually verybrief, honest,clear, well meant and subtle in nature.

But when you have some one who is willing to wedge in between those fundamental moments of conveyances we give teach other –so as to-- mimic those signals but not be sincere; It is such a fundamental betrayal of our subtle, minumal values of unexpressed and unquestioned honest
60 signaling;
That it is very difficult to see! –

THAT is why they always start out with the " WE REALLY WANT THIS-- BIG MONEY ----They are lying or at least not being open and partnering with you as us the people..

66 It is sir and Mams very, very concerning. It is such a betrayal of such miminmal fundamental vaues we give to each other.. This is not a good sign.

if a car or life insurance man came to your door and tried to sell you a policy and acted this way you would ask him and his associate to leave with him..ya know?
And you know why you would do this? Because there is no FATIGUE, GREED or FEAR
72 involved in your decision reasoning

6....They will, if not are now, trying to divide you one at a time..

I cannot convey to you in strong enough terms; I am not sure what the producers are up to; Until you find out you must be prepared to make history at your will; That means in
78 my opinion you must do the following with the Governor participation

1.....Go meet and talk it out.. –DECLARATION OF

" A STATE OF UNUSUAL AFFAIRS"

84 2.....Place yourselves into a temperary salaried status.

3.....Place yourselves into an ongoing state of
" CONTINOUS IN SESSION- YEAR ROUND"
with needs for "vacation or temporary sessation of business"

90 4 ..establish an ending date for the SESSION IN JUNEAU AND
"RECONVENING IN ANCHORAGE AND/OR FAIRBANKS"

5.....Maintain AGIA schedual of needs as per Govenor and Team

6..... Do not get spooked! These are simply times of an unusual "state of affairs"
96 Get a little R&R with your families while your special assignment team sets up your next hearing, cams, and location, etc.!
Important- you do not task your Juneau team or critical mass team that is taking care of everyday business—you can backwash with disruption and workloads if not careful.

7.....Quit calling all the NON producers' buddies and associalte ' (FERC- DOE- PUC)
102 And no more telephone interviews !
Those are just stupid on stupid – you lose and we lose – Ya gotta see a mans eyes and face... You do not want to lose your citizens feeling included in this process.

8. ....You cannot let the non producers drive you! (isolated, detached from familly, travel, fatigue, schedualing, you are being uploaded and down loaded at a hell of a clip here, etc.) the non producers will disassemble you if you let them – you and we all have limitations...Get with the Gov..

9.....Calm, Self Esteem, Relaxed, Patient, Rename and Review "Our Alaskan /American Gas line"--- Talk to California,, Look at WELL HEAD PRICING (the well head pricing I think will make them nervous) DO A HYDROGEN BREAK-FUN LEARN HOW ABOUT A BIG STEEL MANUFACTURER- --NPs probably own them too.

10. I strongly suggest you do not allow any more meetings ON OR OFF CAMERA, OFFICIAL OR UNOFFICIAL with the NON PRODUCERS UNTIL FURTHER NOTICE ! (perhaps, ?? only secure runners)

The NON producers will look to use your request from you "to get back to them in writing" to come back into the picture ! Do not allow this – they will press the issue and entise you with going to give you something-- bullshit .

They can send it over with runner or on secure line. "You people need a little off the burner time".

If I read this right, the non - prod ucers must maintain the full court press and that has certain needs to work – They cannot back off now that the full court press is building !!

You must not allow them to do public cameras again—Unless they are sworn in by a judge and prepared to give official dialogue –

This meandering , evasive, wiggling, wavering, crippled, tortured, twisted, convuluted, knotted, wrinkled, greed titilated, condescending, anti-american, anti-alaskan, cowardly, kaniving, kind bullying, Enron dialogue, of non answered and high school chess like crap is over..

Sometimes in life you have to accept the lot you got or life gives ya: and if it's a battle they want, well, -- If the NPs don't straighten up we gonna send our governor on every commercial and talk shows all across AMERICA—Yea, that should scare the hell out of em...eh humor.. But, I'll bet she could do it!

Sorry about the long letter—I know your busy—Come on, We love big crap!
Inspire us your pepople! This is Alaska!
The *3NPs are all Texans, (Aren't they?)
Do the declaration, money, session and meets thing! Nobody corners or surrounds ya dudes – It's a serrengetti thing!

Paul D. Kendall
907-222-7882

*3NPs – Check it out ! the"3 Non Producers" Is that neat or what ? Yea, see I just invented – well, me and Eddy Burke: He made up the Non Producers,,
I just fashioned it I guess !

----------END----------5-2-07----------

3 pgs total

ALASKA STATE LEGISLATURE

Please enter into the record my testimony to the House Finance
Committee Name

Committee on #179 AGIA
Bill / Subject

Dated 5-5-07

TCC Resolution, copy attached.

SIGNED: Jerry L Woods
Testifier

TANANA Chiefs Conference
Representing

122 First Ave., Fbks., AK 99701
Address / Phone Number

Tanana Chiefs Conference
AGIA Project Labor Agreement Resolution

Whereas; Tanana Chiefs Conference represents forty two sovereign Alaska Native Tribes whose tribal lands include the majority of right of way for any and all of the proposed southern route gas line projects being presently considered, and

Whereas, Tanana Chiefs Conference represents a large potential workforce of underutilized tribal members, both male and female, skilled and non-skilled, and

Whereas, Tanana Chiefs Conference has a sincere desire to build the capacity and skill levels of that workforce to help address village infrastructure construction projects and bring increased economic opportunity to its tribal members both now, and in the future, and

Whereas, Tanana Chiefs Conference and some of its sub-regions and tribes have negotiated project, tribal and other collective bargaining agreements with some of the construction unions, mainly with the Laborers Union and Operating Engineers, with very positive outcomes, and

Whereas, As a result, Tanana Chiefs Conference has seen a marked increase in participation by its tribal members with regards to job opportunities, training programs and apprenticeship programs along with pension plan participation and medical plan participation above and beyond IHS coverage, and

Whereas, Tanana Chiefs Conference is fully supportive of Alaska Native hire and Alaska Local hire on whatever gasline project is finally decided upon, and

Whereas, Tanana Chiefs Conference members supports construction project agreements that along with skills training, pension plans, and medical plans will deliver enforceable Alaska Native, and local, hire language for the construction of whatever gasline project is decided upon, and

Whereas, Tanana Chiefs Conference does not want to repeat what happened during the Trans Alaska Pipeline System Project regarding Alaska Native preference opportunities by not being a part of a comprehensive Project Labor Agreement at the project's inception, and

Whereas, Governor Palin's AGIA bill calls for a negotiated Project Labor Agreement for whatever gasline project is finally decided upon, and

Whereas, Tanana Chiefs Conference has recognized that in light of applicable case law, the best vehicle to define real Alaska residency and real Alaskan Native status to ensure

preference and participation for its tribal members on any proposed gasline project is through a Project Labor Agreement,

Therefore Be It Resolved:

That the Tanana Chiefs Conference supports the Governor Sarah Palin's AGIA plan amendments as long as there is a Project Labor Agreement that contains as one of its tenants, enforceable project participation preference for qualified Alaska Native peoples in numbers and percentages that are generally reflective of the population demographics of the State of Alaska at the time the project begins.

may 4 2007

Alaska Gasline
PORT AUTHORITY

House Finance Committee

May 3, 2007

AGPA Project Description

Alaska Gasline Port Authority

Gas Conditioning Plant in Prudhoe Bay

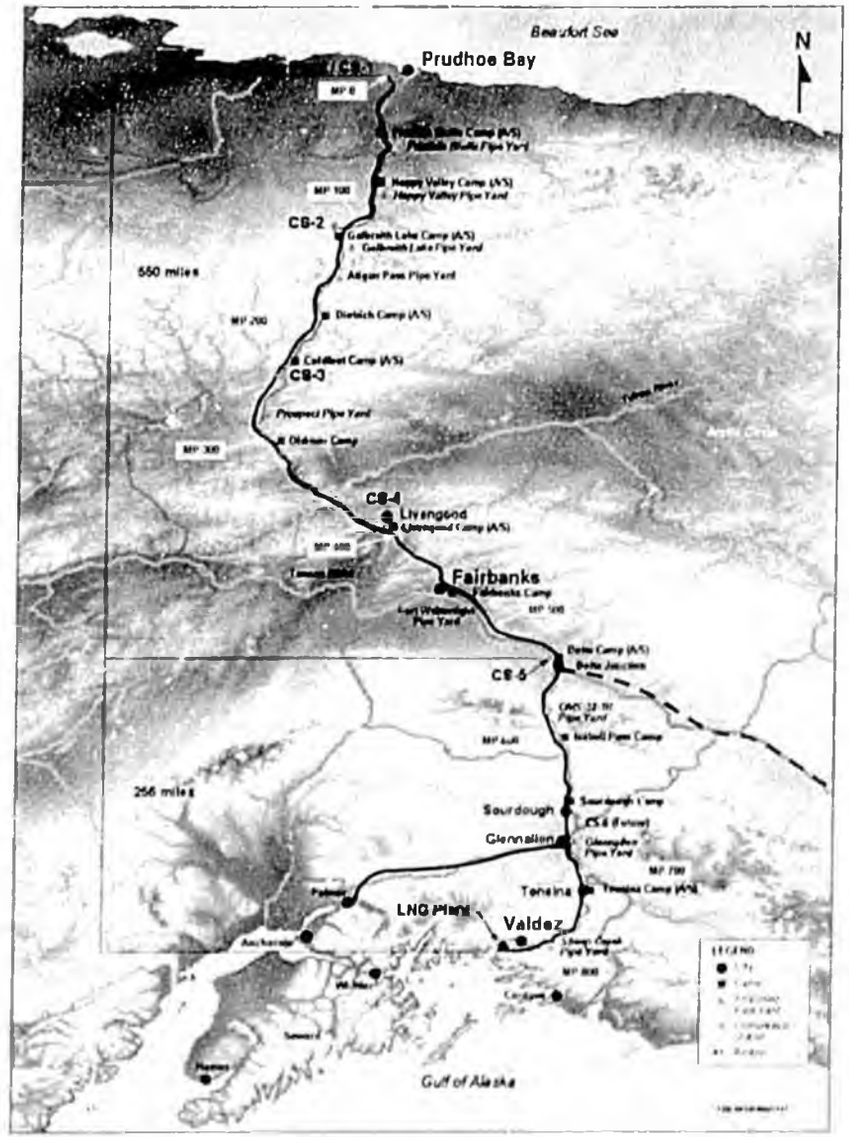
- removes impurities
- compresses and chills the gas to pipeline specifications

Pipeline from Prudhoe Bay to Valdez

- parallel to TAPS (max. capacity: 6 Bcfd)
- pre-build to Delta Junction for later tie-in for the Alaska/Canada Highway Project
- tie-in at Glennallen for a spur line to Alaska South Central natural gas grid

LNG Facility in Valdez

- integrated LNG liquefaction and LPG extraction facilities
- includes storage and vessel loading facilities



Phased Project = Better Cost Overrun Risk Management

Alaska Gasline Port Authority

- 800 mile pipeline is 100% adjacent to TAPS, 100% in Alaska
- Infrastructure in place for entire line – roads, bridges, camp pads, etc.
- LNG project: lower overall cost overrun risk:
  - liquefaction facilities utilize proven technology and well-tested design, resulting in a relatively low level of uncertainty in cost estimate
  - low level of cost uncertainty for LNG marine transportation and regasification
  - pipeline component has the highest capital cost uncertainty – for LNG project the pipeline is only a portion of overall cost to market
- Phase approach with LNG project proceeding first: 2/3 less cost = 2/3 less risk
- Phase 1 can proceed with only one producer- rather than all three

Project Status

Alaska Gasline Port Authority

1. Project Route Permitted

2. The 12 Senior Permits Acquired
   - Yukon Pacific Corporation
   - $100 million expended
   - Right-of-way
   - Project FEIS
   - LNG terminal permit

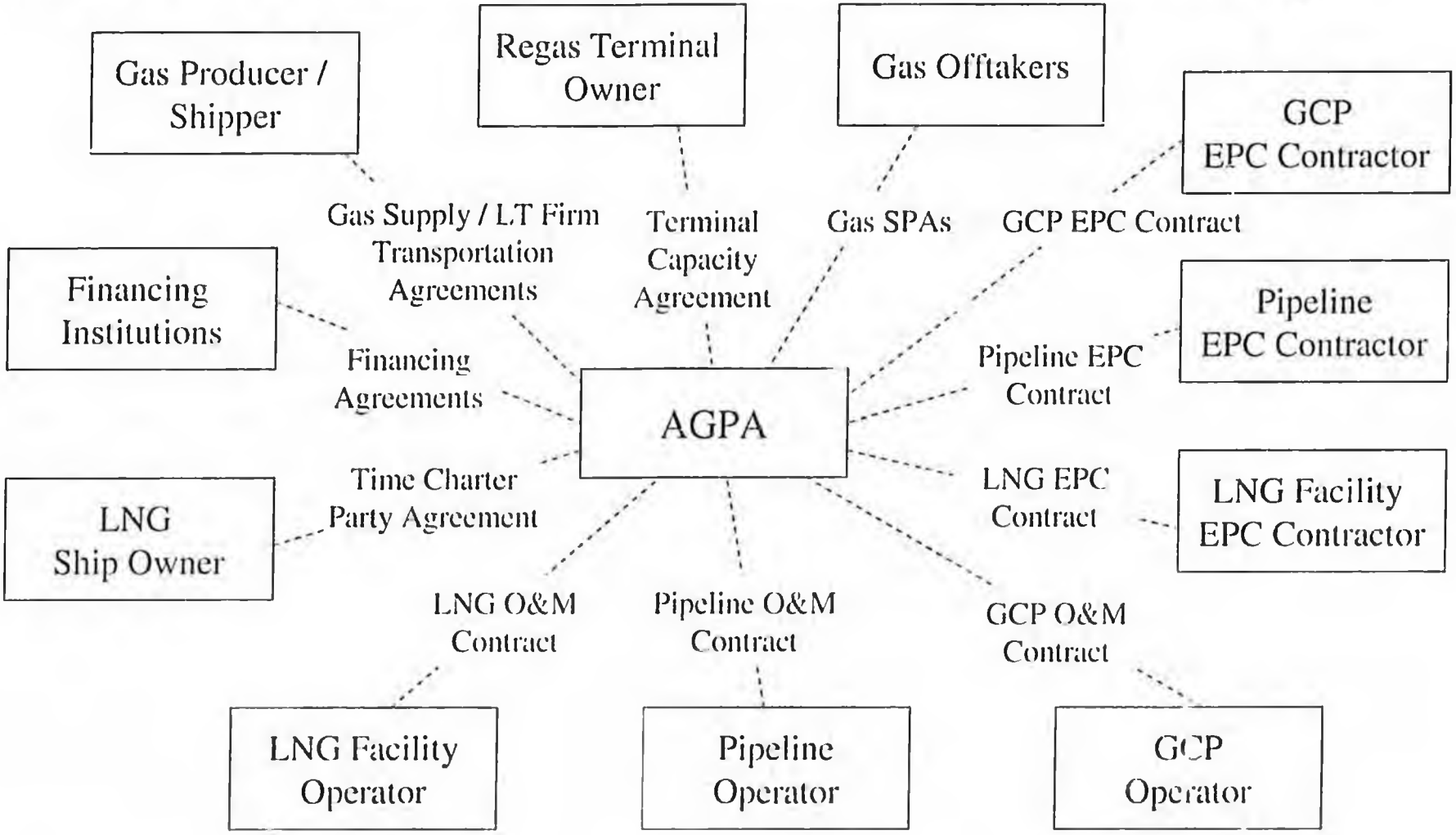
3. Bechtel Cost Estimates
   - Complete & Updated

4. Marine Transportation / Jones Act
   - MOU with the largest LNG shipping company in the world – Mitsui OSK Lines

5. Access to Multiple Markets
   - West Coast receiving terminal under construction
   - West Coast Alternatives
   - Hawaii
   - Pacific Rim

6. Anticipated Financing
   - 80% debt (Federal loan guarantee available)
   - 20% private funding

Indicative AGPA Project Structure



- Industry leaders will be involved in all components of AGPA's project

AGIA is Good for Alaska

Alaska Gasline Port Authority

Alaska Gasline Inducement Act (AGIA) Process:

- Open, transparent and competitive
- Identifies clear evaluation criteria
- Inducements to project applicants in exchange for specific commitments
- Empowers selected applicant to build successful consortium, leading to open season
- Separates the mid-stream from the upstream
- Brings in additional interested parties to develop Alaska's gas resources

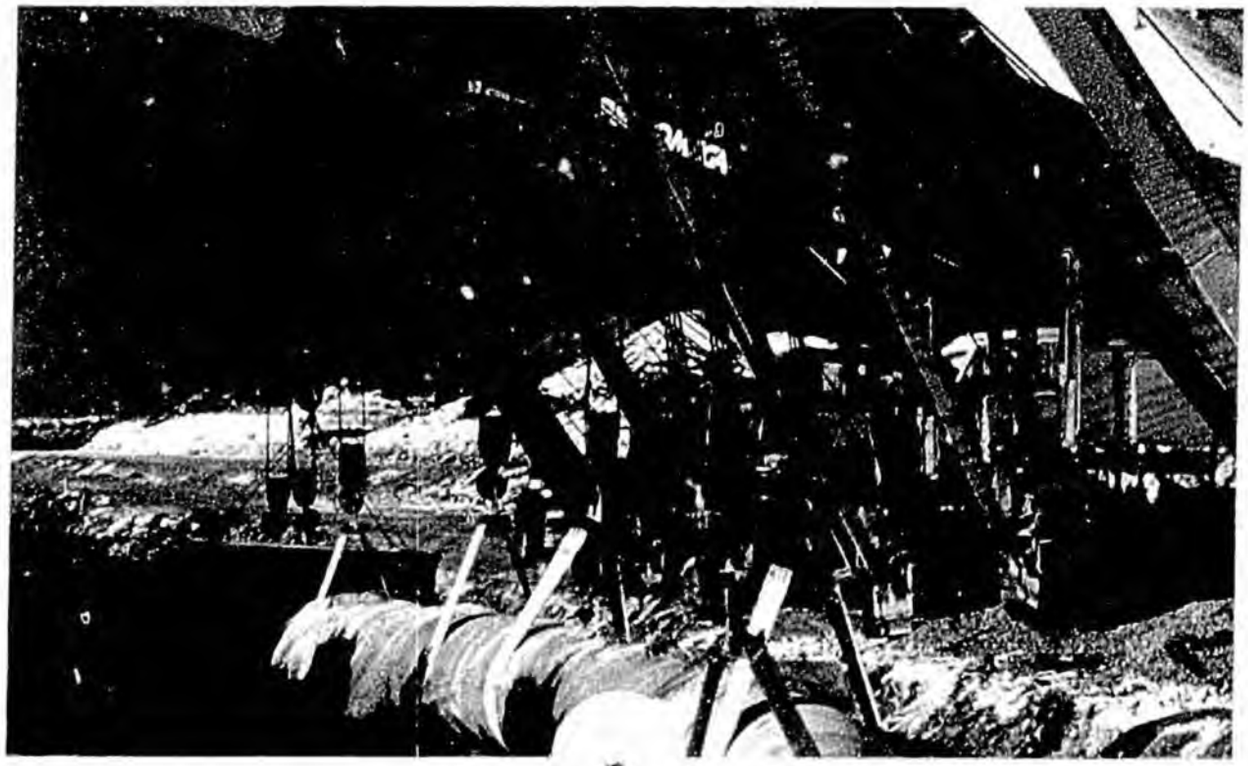
AGIA Suggested Amendments

- Additional gas reserves needed? Budget and timeline for exploration program
- Analysis of making liquids available in Alaska for value added processing
- Current project cost estimate required with application

AGIA benefits towards advancing gas pipeline

- Rolled in rates – good for Alaska's future
- Allows for independently owned infrastructure
- Follows successful model used in other countries who also use rolled in rates and independently owned pipelines.
- $500 million skin in the game – sends very positive message about Alaska's desire to commercialize Alaska's gas
- Supports lowest tariff

The All-Alaska Gasline. The future is on the line.



Alaska Gasline
PORT AUTHORITY

Right Sized – Right Now!

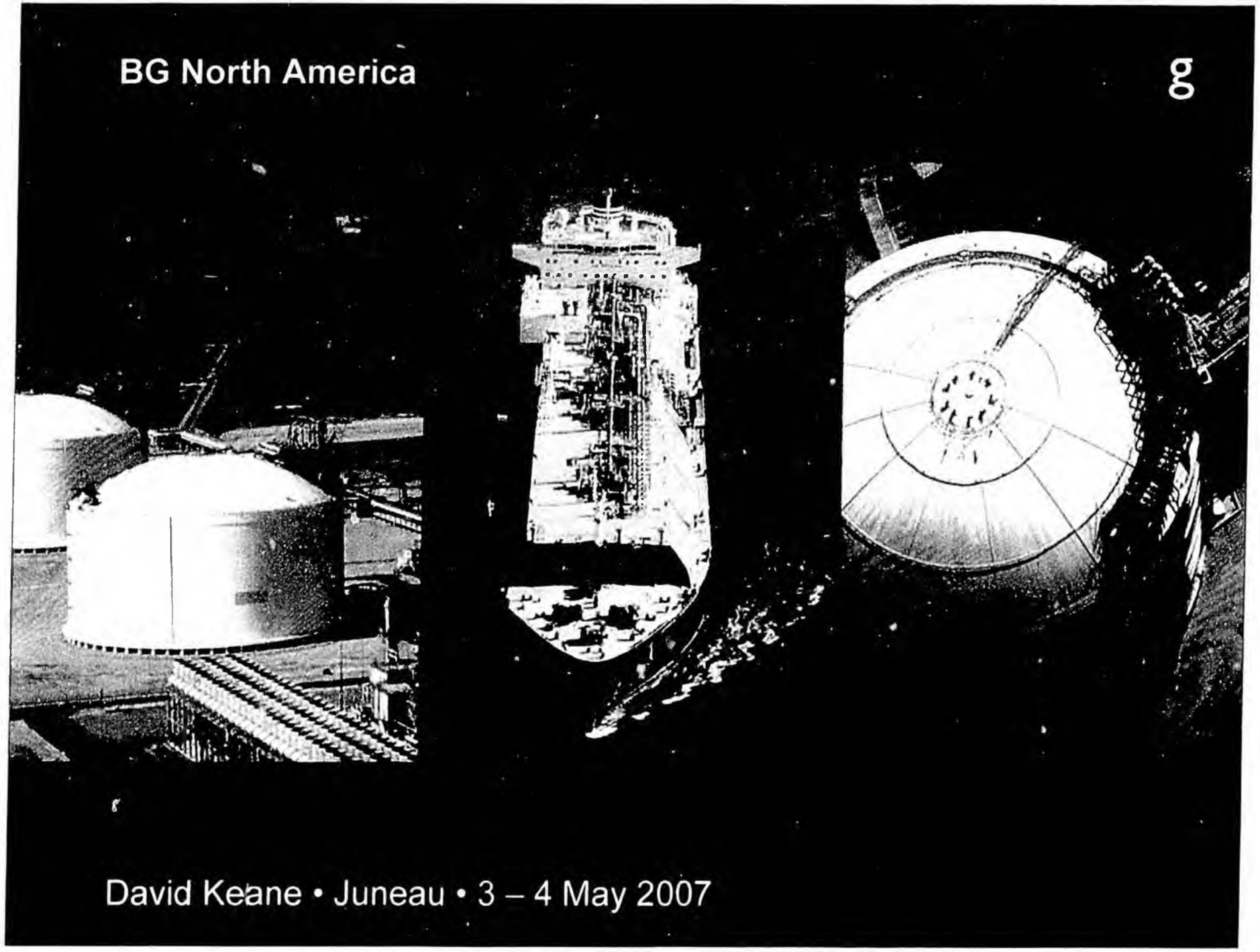
May 4 2007

TransCanada - Proven Basin Developer

Regulatory Structure

- Independent pipeline model
- Rolled-in tolls

May 4th pm



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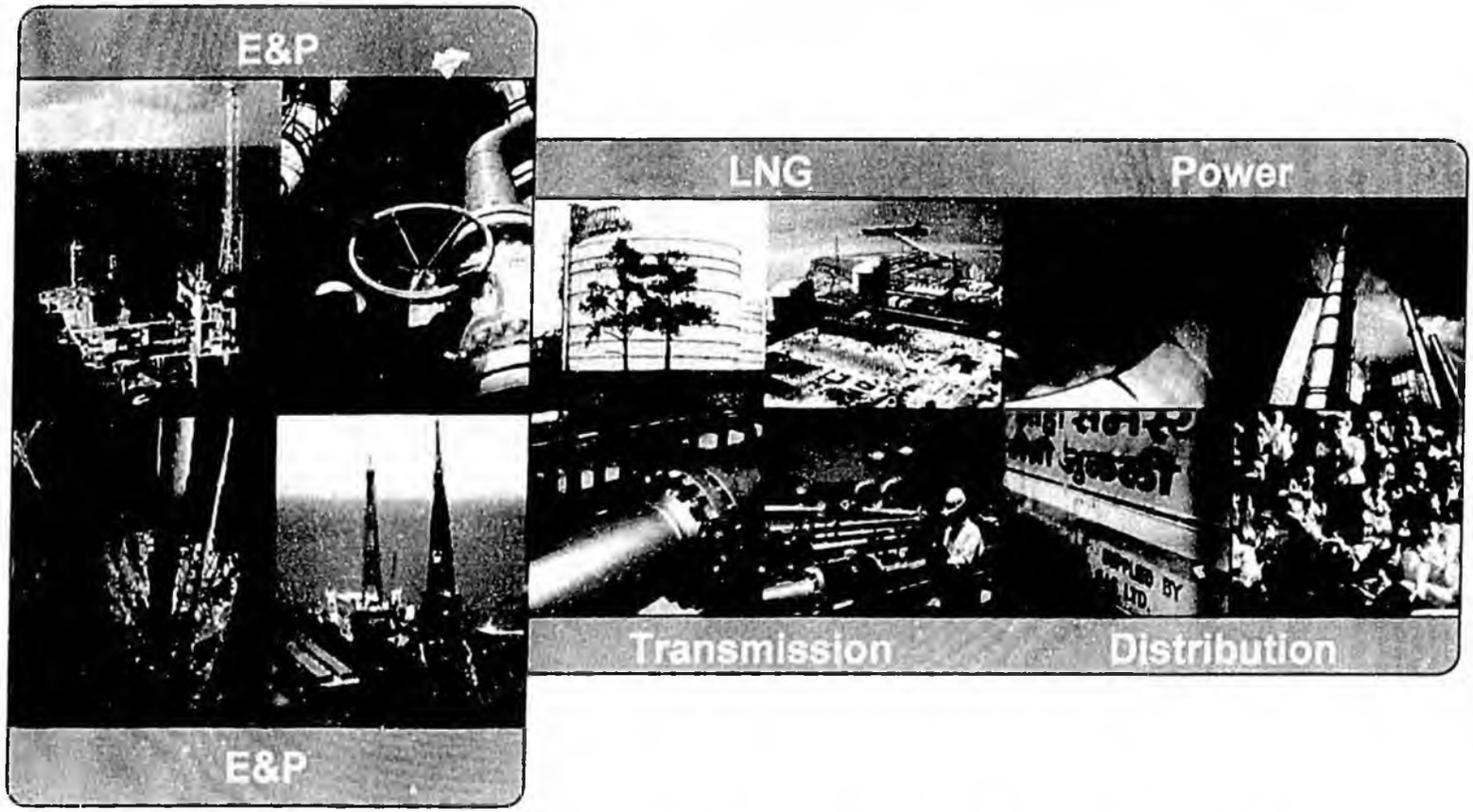
BG Group snapshot

- A world leader in natural gas
- A FTSE 20 company, listed on London and New York Stock Exchanges
- Market capitalisation over $49 billion
- Production circa 70% gas; 30% oil
- Employs approx 4,766 staff; 64% outside UK, at year end 06

Business model

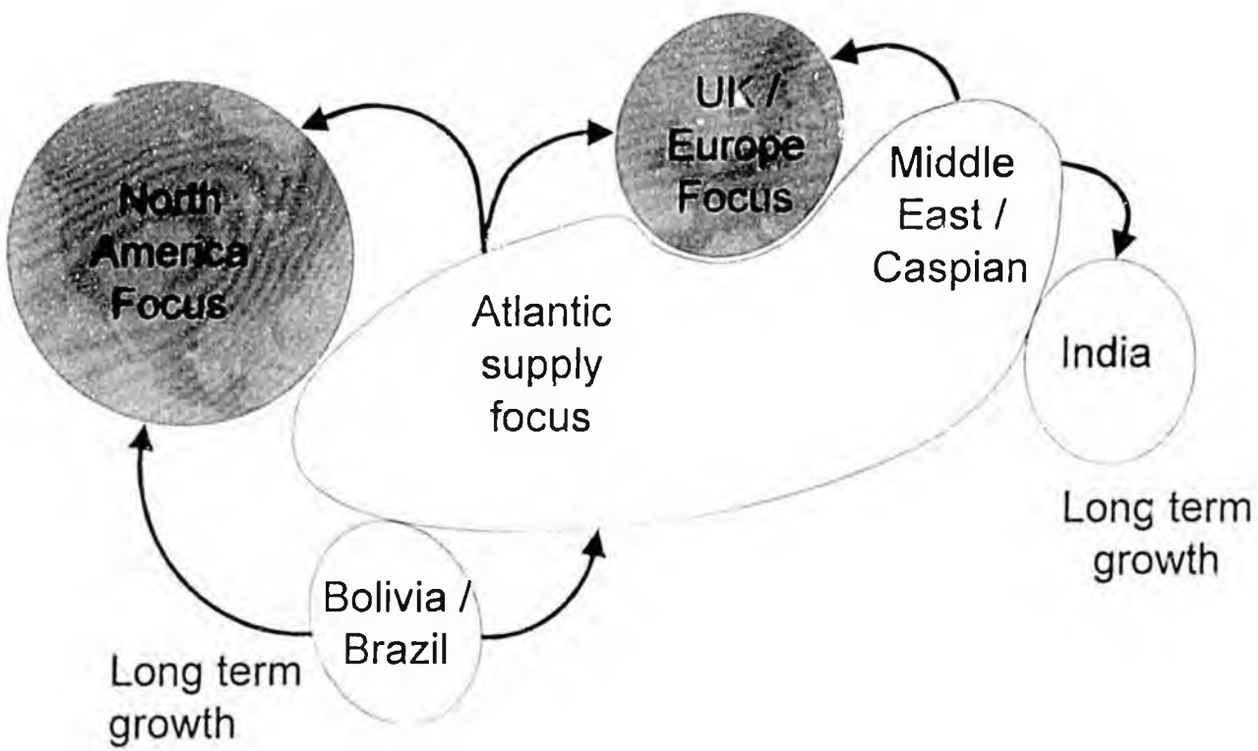


Resources → Enabling → Markets

Countries of current operation

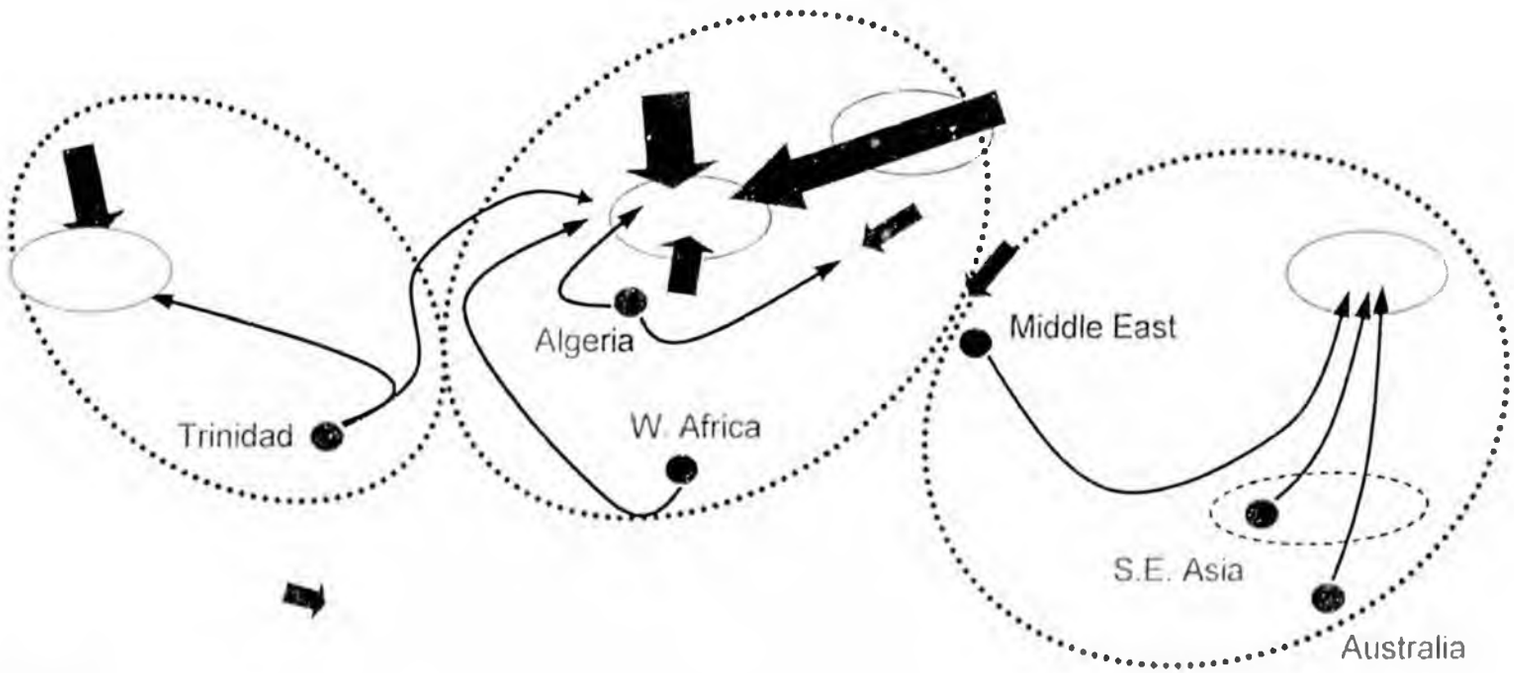
Active in over 25 countries

Gas market focus



Developed Market Developing Market Supplies

Global gas trade – the recent past



Markets

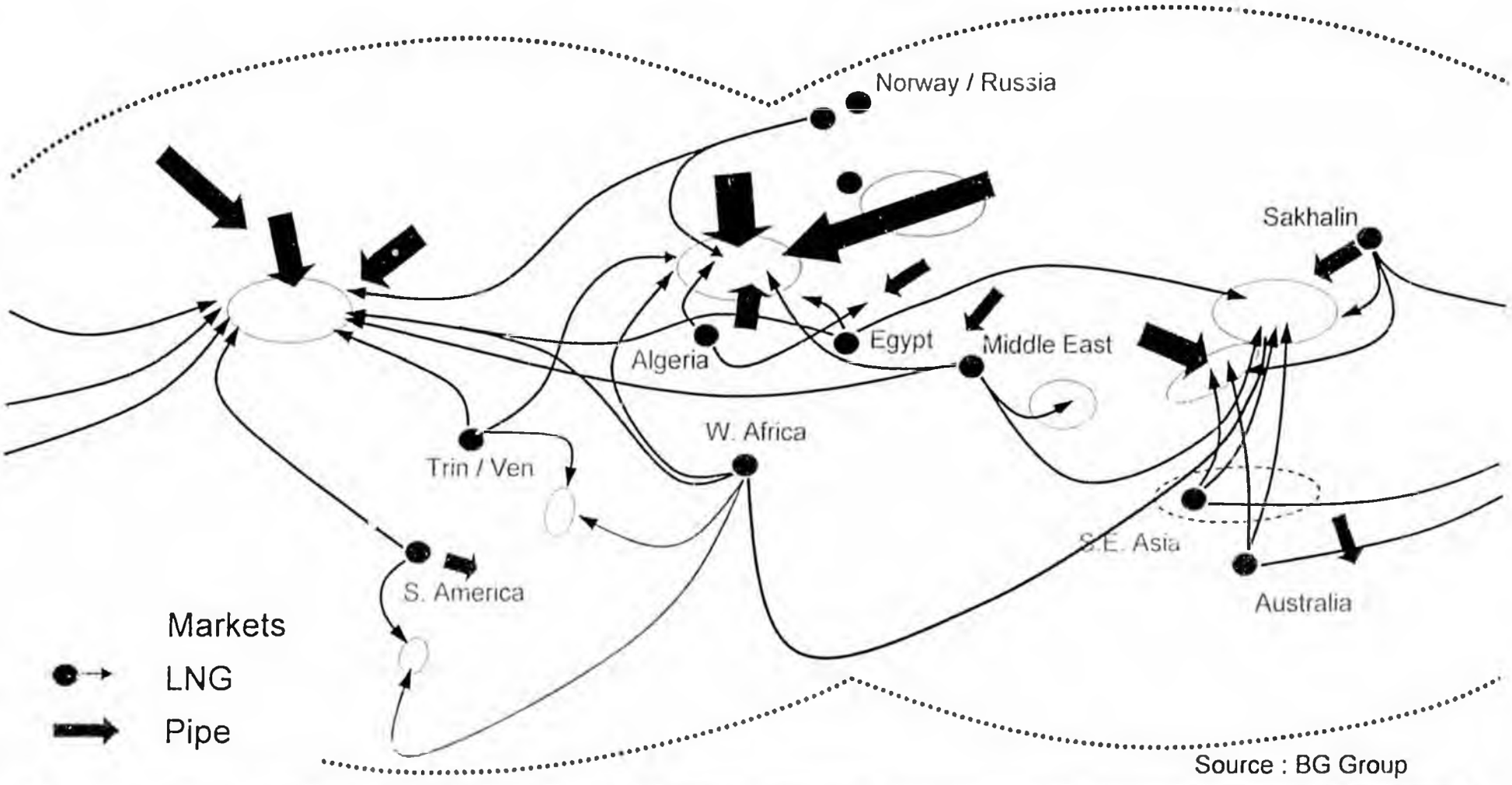
LNG

Pipe

Source : BG Group

Industry evolution: from three main trade regions…

Global gas trade – gradually evolving



Source : BG Group

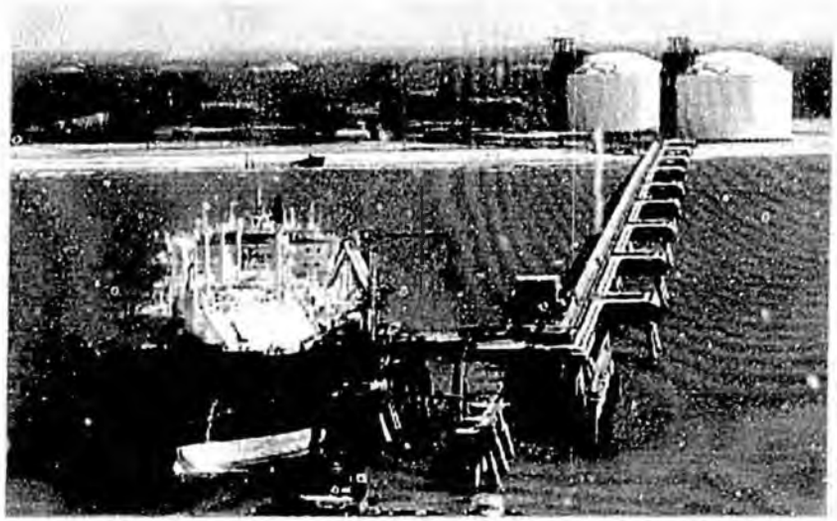
… to a globalising gas industry

BG LNG supply projects

ATLANTIC LNG
COMPANY OF TRINIDAD AND TOBAGO

- Train 1: 3.1 mtpa – 1999 (BG 26.0%)
- Train 2/3: 6.6 mtpa – 2002 (BG 32.5%)
- Train 4: 5.2 mtpa – 2005 (BG 28.9%)
- BG initiated project and was instrumental in Phillips design
- Single train start-up

Liquefied Natural Gas
Egyptian LNG

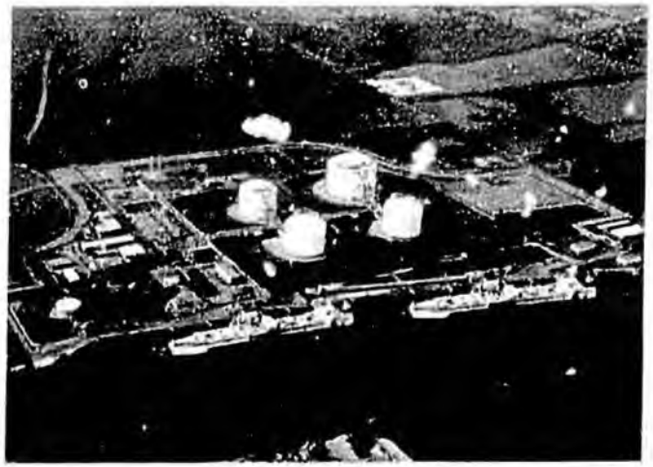


- Train 1: 3.6 mtpa – 2005 (BG 35.5%)
- Train 2: 3.6 mtpa – 2005 (BG 38.0%)
- Egypt's largest project financing to date
- Unique project commercial structure
- Utilized lessons learnt from ALNG

Atlantic LNG – total export capacity of 15 mtpa in just 7 years

US market summary

- Lake Charles import terminal
- Phase I expansion Q4 2005
  - 1.2 bcf/d sustainable send out
  - 1.5 bcf/d peak send out
  - 9.1 bcf total storage
- Phase II expansion Q2 2006
  - 1.8 bcf/d sustainable send out
  - 2.1 bcf/d peak send out
- Elba Island import terminal
  - 0.45 bcf/d sustainable send out
  - 0.67 bcf/d peak send out
  - 4.0 bcf storage capacity
  - 1.17 bcf/d firm send out & 8.2 bcf storage after second expansion

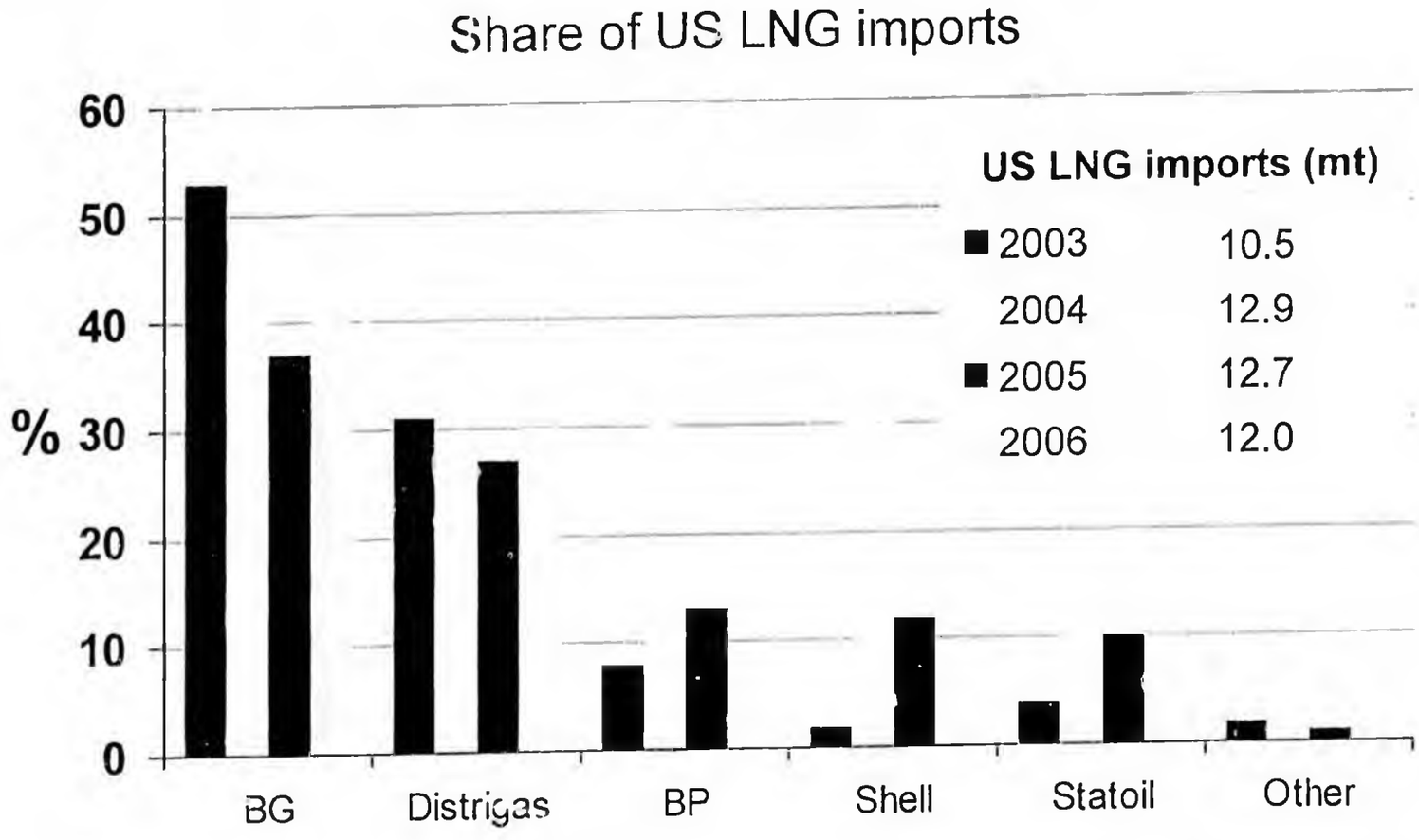


Lake Charles

Elba Island

Capacity in two of the four existing US onshore terminals

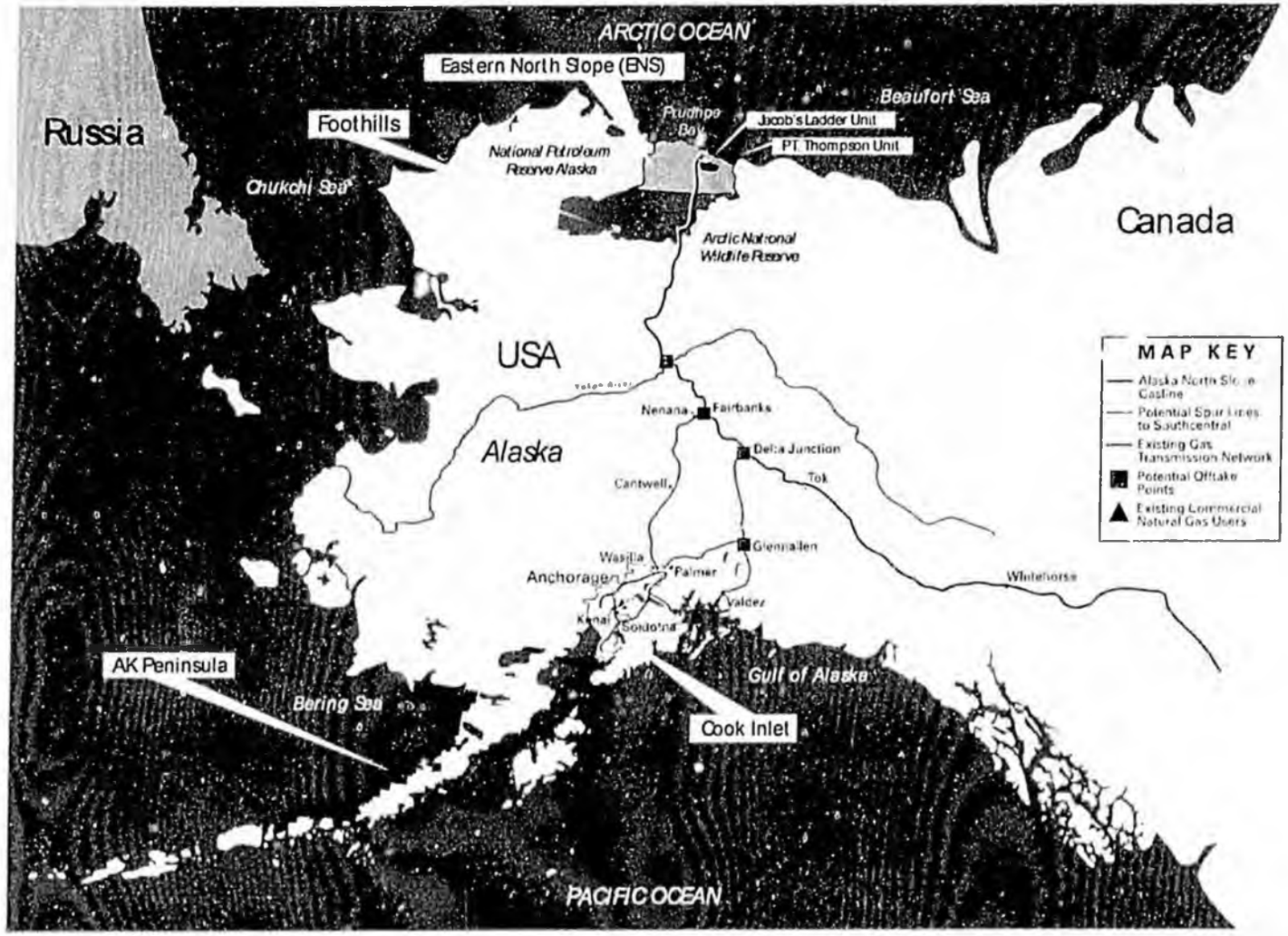
LNG imports – 2003 to present



Source : DOE

BG – the largest US LNG importer in 2003, 2004, 2005 and 2006

Alaska E&P



2.1 million acres in the Foothills of ANS and .2 million in the ENS

Alaska Gasline Inducements Act

- BG is investing in Alaska
  - Exploring along North Slope and ENS
- BG supports AGIA
  - The process is fair, open and inclusive
  - BG supports the mandatory provisions on access and rates
  - Will encourage new explorers to invest in Alaska
- AGIA provides:
  - Opportunities for input by all interested parties
  - Several opportunities for legislators to provide input:
    - Initial legislation
    - When pipeline applications are submitted
    - Legislative review of the winning application

AGIA will encourage development

Alaska Gasline Inducements Act

- AGIA addresses BG's concerns by:
  - Providing a level playing field for all participants
  - Providing certainty that when we discover gas, we will have access to pipeline capacity
  - Providing a mechanism to ensure just and reasonable rates
- AGIA creates competition to build the pipeline and possibly an LNG export facility
- AGIA spells out what is required of any applicant
- Clearly identifies the State's "must haves"
- BG's "must haves" are:
  - Regulated pipeline
  - Open access provisions in the tariff
  - Just and reasonable rates

AGIA will encourage development

Key messages

- AGIA is good for Alaska and for the natural gas industry
- AGIA will encourage the continued development of Alaska's untapped natural gas reserves
- AGIA's purpose:
  - "…to encourage expedited construction of a natural gas pipeline that

  (1) Facilitates commercialization of North Slope gas resources of the state;

  (2) promotes exploration and development of oil and gas resources on the North Slope;

  (3) maximizes benefits to the people of the state from the development of oil and gas resources in the state; and

  (4) encourages oil and gas lessees and other persons in the state to commit natural gas from the North Slope to a gas pipeline system for transportation to markets in this state or elsewhere."


BG North America

5/4/07

TESTIMONY OF JOHN K.NORMAN, CHAIR AOGCC
HOUSE FINANCE COMMITTTEE
HB 177
MAY 4, 2007

This afternoon I'll discuss the AOGCC's role in North Slope gas sales and give you a status report.

Most knowledgeable Alaskans know the significance of 35 TCF of natural gas. However, very few people realize that hundreds of millions of barrels of oil and condensate could be lost if gas offtake is not correctly managed.

Oil is Alaska's bird in the hand and gas is our bird in the bush. The AOGCC is responsible for setting the gas offtake allowables from the North Slope oil fields to ensure that we do not harm our bird in the hand while aspiring to grasp our bird in the bush.

In general, maintaining reservoir pressure enhances oil recovery, but producing gas depletes reservoir pressure. Therefore, gas reserves in most fields are usually sold only after most of the oil has been produced. Until then, the gas that is produced with the oil is used to promote increased liquid production in various ways.

For example, gas might be reinjected into the reservoir to provide the energy needed to get the liquid hydrocarbons to the surface, or the gas might be used for enhanced oil recovery operations.

Both of those are happening right now at Prudhoe Bay and other North Slope fields.

Therefore, North Slope gas sales are going to involve trade-offs between oil and gas recovery. It's not practical to get every drop of oil out of the ground before starting gas sales, and the AOGCC

certainly does not take that position. We do however need to ensure that the trade-offs that inevitably will occur result in greater ultimate recovery of both gas and oil

It is important to understand that Prudhoe Bay does have a existing gas offtake allowable. It is 2.7 BCF per day and it was set in 1977.

The AOGCC usually waits for an application from the operator to modify pool rules including offtake rates. However, in 2005 we recognized the following:

First, that serious discussions were taking place concerning major North Slope gas sales

Second, that the 2.7 BCF per day gas offtake allowable for Prudhoe Bay was set in 1977, when the field first began to produce; and, although that offtake rate was based on the best available information at the time, we now have 30 years and 11 billion barrels of production and production-related data to help determine a better number

Third, most of the publicly discussed pipeline options could require more than 2.7 BCF per day offtake from Prudhoe Bay

Forth, performing the necessary studies to determine an appropriate current offtake rate would take time, and

Fifth, the AOGCC did NOT want to be the cause of any project delays.

Therefore, to acquire the most current information, BP and the other Prudhoe Bay working interest owners agreed to provide the AOGCC staff and consultants access to their simulators including the underlying engineering, geologic, and geophysical information. They voluntarily set up a data room in BP's Anchorage offices,

equipped with computers and software allowing review of the simulator results.

It is important to note that the data and information provided to us falls within the standards of AS 31.05.035(d) and 20 AAC 25.537(b) governing confidentiality of information.

In simple terms, the data that has been made available to us is not something we were otherwise entitled to. It belonged solely to the Prudhoe Bay working interest owners. We needed it to perform our study, and the most efficient way for us to get access to it was to agree to keep it confidential.

Our most recent study began in January 2006, and was completed in late 2006. In the course of that study, BP and its partners were cooperative and provided us all that we needed.

On February 28, 2007, we published a summary report. That report is available on the AOGCC website (www.aogcc.alaska.gov); and a copy is in your packet.

As soon as we announced that we had completed our study, everyone wanted to know the magic number, but it's not that easy.

First, it's a multi-variable equation. The right offtake volume will depend on when sales start, how aggressively the oil has been produced in the meantime, and what mitigating steps are in place and planned. And second, there are legal restrictions on what results of the study we can share and how we share them.

As soon as we receive an application or otherwise have enough information to make a meaningful determination, we will convene public hearings and make as much information available as is needed and legally allowed to support any change in the assigned natural gas offtake allowable.

It is our intent to complete our evaluations, hold hearings and make our final rulings on gas offtake allowables for both Prudhoe Bay and Pt Thomson well in time for the "open season" process.

As of now, here's what we can say:

(1) The later gas sales begin, the smaller will be the oil losses.

(2) The lower the offtake rate, the smaller will be the oil losses.

(3) The more the oil production is accelerated before gas sales start, the smaller will be the oil losses.

(4) The more that is done to mitigate detrimental effects of gas sales, the smaller will be the oil losses.

(5) Oil loss is more sensitive to the acceleration of oil production and the mitigating steps than it is to start-up timing or offtake rate.

(6) Depending on the life of the North Slope infrastructure, delaying gas offtake too long, could result in decreased gas recovery.

By the time a pipeline project is ready, selling gas from Prudhoe Bay can very likely proceed at a higher offtake rate than the current 2.7 BCF per day, provided BP and its partners continue working: (1) to accelerate oil production (for example: aggressive infield drilling and operational vigilance to minimize production interruptions) and (2) to mitigate for gas losses (gas cap water injection and using CO2 for EOR, for example).

We are confident, that unless a substantial delay occurs (which could make our analysis stale and require additional analytical work), we will be adequately prepared to make a timely determination of the correct Prudhoe Bay gas offtake allowable rate when an application does come before us.

Now, I would like to talk about Pt Thomson, where we can't make such a confident statement.

A year ago the AOGCC, and Exxon and its partners agreed upon a similar process for studying the allowable gas offtake from Pt Thomson. The AOGCC contracted reservoir evaluation consultants to assist its technical staff in performing the Pt Thomson study. Exxon and its partners agreed to give AOGCC staff and consultants access to a data room in Exxon's Houston offices. It was agreed that the data room would include reservoir engineering, geologic and simulation information and would be equipped with computers and software allowing review of the simulator results. The study was supposed to begin before September 2006 and last up to six months. Exxon and its partners indicated that they planned to apply to the Commission in late 2006 or early 2007 for Pool Rules and a gas offtake allowable rate for Pt Thomson.

Unfortunately we were not able to follow that time line. Exxon had delays in preparing the data room and information. The process was finally slated to begin late last year, about the same time that the DNR found Exxon and its partners to be in default on their leases. We attended one meeting where Exxon presented a small portion of the information we would need, but since then the study has been <u>on hold</u> pending resolution of legal issues.

Without a thorough study, it will be very difficult for the AOGCC to have sufficient information to make a gas offtake ruling on Pt Thomson. So that one remains a wild card – in many ways.

In summary:

(1) There are hundreds of millions of barrels of oil and condensate at risk if Alaska doesn't manage natural gas offtake properly.

(2) The AOGCC is charged with setting gas offtake allowables that will prevent loss of the State's valuable hydrocarbon resources.

(3) The AOGCC intends to perform its function so that we will not delay the project, i.e., before an open season.

(4) We've done the technical work to prepare us to address Prudhoe Bay's offtake without causing that delay.

(5) A lot remains to be done for Pt Thomson; so delay is possible there.

Thank you and I would be happy to take your questions.

5/4/07

The Palin-Parnell Administration presents

AGIA

The Alaska Gasline Inducement Act

Alaska Gasline Project from Lenders' Perspective
Presentation to House Finance
5/2/2007

The Lenders' Perspective

AGIA
The Alaska Gasline Inducement Act

Lenders consider 5 Cs:

- **Capacity**
  - The debt repayment capability of the pipeline project.
- **Collateral**
  - The secondary source of debt repayment.
- **Character / Credit**
  - Project sponsors (the active equity investors) who are experienced in the pipeline industry and have solid credit history.
- **Commitment**
  - Financial and non-financial commitments from sponsors indicating their incentives to the success of the pipeline project.
- **Conditions**
  - Future market, regulatory, economic and environmental conditions that could impact the viability of the project.

Financing Perspective

AGIA
The Alaska Gasline Inducement Act

- The critical items for a greenfield natural gas export pipeline from Alaska include:
  - Firm long term commitments to ship natural gas, at a price, quantity, and term sufficient to service and repay the necessary debt financing.
  - Equity funding, typically of 20%-30% of the project's forecast capital structure. One or more equity sponsors with the project development, management, and operations skills necessary to undertake this project. will drive ↑ pipeline tariff
  - Division of cost overrun risks among parties which have the financial strength, and appropriate skills and incentives to manage and bear this risk.
  - FERC, NEB, and other regulatory approvals

- Each of these critical elements is magnified due to the extraordinary size of the proposed project.

- Federal loan guarantees will be helpful in maximizing the quantity of debt and limiting the cost of pipeline debt financing, (and the delivered cost of pipeline gas to consumers), but are not a substitute for any of the key elements listed above.

Firm Transportation (FT) Commitments

AGIA
The Alaska Gasline Inducement Act

- Firm long term commitments to ship natural gas, at a price, quantity, and term sufficient to service and repay the necessary debt financing are normally necessary for a successful financing.
  - Demonstrate (via open season) the need for the project from regulatory perspective
  - Provide equity investors with necessary assurance of earning an acceptable return
  - Critical to give lenders assurance of debt repayment (in absence of federal guarantee)

- Bulk of the shipper commitments will very likely come from the parties which own the gas supply.
  - Only the producers have sufficient economic interest to make firm transportation commitment
  - Given the high level of capital expenditure necessary for the project, the exact terms of the shipping commitments are of great importance to suppliers in determining the acceptability of their economics
  - Shipper commitments are normally needed 1) prior to closing on debt financing and pipeline construction, and 2) prior to equity making large "at risk" commitments – including large pre-approval development outlays

Equity Commitments

AGIA
The Alaska Gasline Inducement Act

- Equity Commitments are a pre-condition to debt financing and federal guarantees
- Typical greenfield FERC regulated pipeline project is funded with 20%-30% base equity.
  - Exact level is dependent upon project economics and reserves, but some minimum needed to establish sponsor credibility as owner
- Ability to attract equity sponsors rests upon ability to:
  - attract sufficient firm and binding transportation commitments
  - share development cost risks with other interested parties
  - share cost overrun risks with shippers
  - provide a clear regulatory path to approval

Cost Overruns

AGIA
The Alaska Gasline Inducement Act

- Mitigating cost overruns is a key financing concern

- Substantial increases in cost of large capital projects have occurred in recent years, across many industries globally.
  - Complex causes, including higher commodity prices and skilled labor shortages
  - Extreme cost overruns have occurred for mega-projects in the nearby Alberta oil sands

- Because of market conditions, and the project size, there is a limited ability to shift cost overrun risk to contractors and suppliers.

- The magnitude of cost overrun risk, and the modest equity returns typically associated with pipeline equity, will likely drive some need for sharing of this risk between equity investors and shippers
  - Shippers, in turn, will need more protection against potentially very large cost overruns than would be provided in a typical "cost of service" arrangement

Department of Energy Loan Guarantees

AGIA
The Alaska Gasline Inducement Act

- The Alaska Natural Gas Pipeline Act of 2004 gave the U.S. Department of Energy the ability to issue up to US$18 billion in loan guarantees in support of the Alaska natural gas pipeline project.

- Key loan guarantee provisions in Alaska Natural Gas Pipeline Act of 2004 are extremely favorable.
  - Maximum guaranteed debt would be the lesser of US$18 billion (indexed to inflation) or 80% of total capital costs, including interest during construction
  - Owners of Canadian portion of pipeline also eligible
  - Term of 30 years
  - Unusual credit support language indicating that no "*contractual commitment or other form of credit support of the sponsors (other than equity contribution commitments and completion guarantees) or ... throughput or other guarantee from prospective shippers greater than such guarantees as shall be required by the project owners*" will be required for loan guarantee

- Favorable terms of legislation may be limited by practicalities of Department of Energy implementation:
  - DoE has been slow to implement the loan guarantee provisions of the Energy Policy Act of 2005
  - DoE solicited public feedback in May 2005 to assist in future rulemaking on pipeline loan guarantees, but has yet to issue any further guidelines or draft regulations

Conclusions

AGIA
The Alaska Gasline Inducement Act

- AGIA has some helpful elements
  - Up to $500 million of risk sharing capital during the project development phase, the most risky stage of the pipeline project
  - The Resource Inducement section encourages FT commitments
  - A requirement that an application shall describe the means for preventing or managing cost overruns for the proposed project

- A pipeline will not be built without lenders' debt financing

- The financing of the pipeline project needs to be supported by firm transportation commitments, a robust federal guarantee, or a combination of both.

- Finally, there is a lot of what ifs and unknowns with this project, but there is nothing in AGIA which would preclude project financing.

SARAH PALIN, GOVERNOR

ALASKA OIL AND GAS CONSERVATION COMMISSION

333 W 7th AVENUE, SUITE 100
ANCHORAGE, ALASKA 99501-3539
PHONE (907) 279-1433
FAX (907) 276-7542

May 2, 2007

Honorable Harry T. Crawford, Jr.
State Representative
Alaska State Capitol
Juneau, Alaska 99801

Re: Total North Slope Field Fuel Uses

Dear Representative Crawford:

In a letter dated April 27, 2007 you requested total North Slope fuel uses for all uses including flaring for 1996, 1998, 2000, 2002, 2004, and 2006. Attached is a spreadsheet of total North Slope Field gas disposition for years 1974-2007.

If you need anything further, please let me know.

Sincerely,

Cathy P. Foerster
Commissioner

5/4/07

GAS DISPOSITION
NORTH SLOPE

Year	Sold	Reinjected	Lease Operations	Other (Shrink)	Flare ≤ 1 Hr	Flare > 1 Hr	Flare Pre-1995	Pilot / Purge	TOTAL (MCF)
1974	136,267	0	1,574,493	0	0	0	1,076,405	0	1,710,760
1975	0	0	1,747,392	0	0	0	1,061,146	0	1,747,392
1976	0	0	2,601,672	0	0	0	1,253,565	0	2,601,672
1977	1,089,266	68,079,911	13,562,344	0	0	0	10,871,756	0	82,731,521
1978	0	271,854,320	18,826,145	0	0	0	2,313,159	0	290,680,465
1979	0	390,135,672	23,559,180	0	0	0	1,840,081	0	413,694,852
1980	0	546,509,480	28,967,138	0	0	0	1,800,728	0	575,476,618
1981	8,581,676	595,105,936	35,933,705	0	0	0	2,463,982	0	639,621,317
1982	14,000,336	715,615,225	48,430,730	0	0	0	3,504,533	0	778,046,291
1983	14,588,522	791,979,337	55,686,290	0	0	0	2,524,293	0	862,254,149
1984	15,088,326	815,929,228	68,917,316	0	0	0	5,893,379	0	899,934,870
1985	20,088,651	932,433,536	87,583,097	429,994	0	0	3,955,943	0	1,040,535,278
1986	20,000,566	974,346,448	89,987,287	6,737,128	0	0	5,909,843	0	1,091,071,429
1987	43,382,200	1,246,008,090	122,987,338	2,642,510	0	0	12,961,727	0	1,415,020,138
1988	48,581,554	1,454,630,573	146,017,694	610,195	0	0	5,798,801	0	1,649,840,016
1989	39,809,917	1,465,365,209	155,574,755	1,088,024	0	0	6,920,191	0	1,661,837,905
1990	37,680,944	1,546,787,029	159,170,572	1,141,078	0	0	8,698,009	0	1,744,779,623
1991	45,592,431	1,854,612,855	175,112,147	1,582,330	0	0	7,101,603	0	2,076,899,763
1992	48,663,964	2,086,288,595	184,023,821	1,940,119	0	0	10,092,493	0	2,320,916,499
1993	46,345,834	2,246,166,126	187,167,540	2,025,671	0	0	19,083,628	0	2,481,705,371
1994	44,232,750	2,536,387,742	198,462,396	1,930,184	0	0	10,585,018	0	2,781,013,072
1995	48,638,357	2,834,319,492	205,658,266	4,751,106	1,008,526	2,263,885	0	3,605,648	3,100,245,280
1996	53,544,447	2,853,814,382	213,108,235	0	1,171,569	1,113,525	0	3,512,626	3,126,264,784
1997	54,501,684	2,874,258,399	215,808,275	0	1,050,985	1,933,793	0	3,270,717	3,150,823,853
1998	51,852,342	2,899,208,855	212,765,726	1,647,273	1,210,457	1,472,868	0	3,395,919	3,171,553,440
1999	50,246,879	2,892,680,089	208,818,872	3,206,077	1,221,949	854,100	0	3,315,505	3,160,543,471
2000	50,712,585	3,063,581,153	211,912,214	1,857,203	932,830	1,651,148	0	3,418,412	3,334,065,545
2001	49,223,417	2,948,515,834	212,038,799	3,269,346	900,484	1,270,145	0	3,575,528	3,218,793,553
2002	66,411,281	3,009,055,700	224,109,025	2,447,053	672,553	1,690,210	0	3,597,633	3,307,983,455
2003	79,951,162	3,096,531,473	229,135,954	13,852,661	741,039	702,759	0	3,762,183	3,424,677,231
2004	77,333,706	3,139,951,408	225,997,941	11,885,313	565,855	1,119,781	0	3,779,555	3,460,633,559
2005	69,144,592	3,135,383,457	234,984,760	15,206,869	629,632	755,822	0	3,825,405	3,459,930,537
2006	63,428,748	2,737,906,016	208,176,807	13,294,234	826,496	1,486,366	0	3,789,735	3,028,908,402
2007	17,341,239	795,895,664	59,079,682	5,730,234	130,539	166 831		938,949	879,283,138

5/2/07

5-1-07

ExxonMobil AGIA Testimony
House Finance Committee 5-2-07

testimony

FINANCE COMMITTEE:

Co-Chairmen: Representatives Mike Chenault (R) / Kevin Meyer (R)
Vice-Chair: Representative Bill Stoltz(R)
Members: Representatives Richard Foster (D); Mike Hawker (R); Mike Kelly (R); Bill Thomas, Jr. (R); Harry Crawford (D); Les Gara (D); Reggie Joule (D); Mary Nelson (D)

INTRODUCTION

Good afternoon Chairmen Chenault and Meyer, Vice-Chair Stoltz and members of the House Finance Committee. My name is Marty Massey. I am the U.S. Joint Interest Manager for ExxonMobil, a position I have held since November 2001, and I am responsible for the commercialization of ExxonMobil's gas resources in Alaska.

ExxonMobil has been in Alaska for over 50 years and has been a key player in Alaska's oil industry development. We hold the largest working interest at Prudhoe Bay (36.4%) and our current net production in Alaska is approximately 150,000 barrels per day. We have benefited from our involvement in the State of Alaska, and we believe that Alaska has benefited from this long-term relationship as well. Commercializing Alaska's North Slope gas will allow us to continue this mutually beneficial relationship for another 50 years or more.

EXXONMOBIL READY TO PROGRESS PROJECT

The Alaska Gas Pipeline Project is important to Alaska, to our nation, and to ExxonMobil. The project has the potential to generate billions of dollars in revenues for the State of Alaska, the U.S. federal government, and Canada, and could provide a stable and secure source of clean energy for Alaska and North America for decades to

come. For ExxonMobil, the project is significant and has the potential to add over 1 billion cubic feet per day of gas sales, which would be more than a 10% increase to our current worldwide daily gas production. This project could also add over one billion oil-equivalent barrels to proved reserves, nearly enough to replace a year of our production. Given the significant impact this project could have on our business, we strongly support efforts to advance a pipeline project.

As an illustration of our commitment, ExxonMobil has spent more than $180 million studying ways to commercialize Alaska gas. Since the 1970's we have evaluated LNG, gas to liquids and gas pipeline alternatives. Based on these studies we have determined that a Producer Gas Pipeline Project will result in the best value for the State, the Producers and the nation.

GENERAL FEEDBACK ON AGIA

I would now like to provide you with some feedback on AGIA. ExxonMobil embraces the concept of competition all over the world and is ready to participate in a competitive and market-based environment. AGIA, as it is written today, does not encourage market-based competition due to its prescriptive nature. In addition, AGIA does not adequately address the significant upstream issues and risks associated with the scale and magnitude of the Alaska Gas Pipeline Project. We have consistently advised the Legislature and the Administration that AGIA, in its current form, will not encourage competitive proposals and will not result in a commercially viable project. We strongly believe AGIA will not create an acceptable framework for this world-scale mega-project unless it allows the parties taking the risks to make a proposal that properly manages the risks.

After listening to the testimony over the past several weeks, it has become clear to me that one of the reasons the Administration's view of the project is so different from ours is due to flawed assumptions in the State's economic model. The Administration's model fails to recognize the integrated nature of this basin-opening project. The upstream pays for the midstream and you cannot split them apart when evaluating commercial viability. Any attempt to do so will deliver erroneous results. This issue is critically important, because if you put in place a process based on a flawed analysis, it will most likely fail. For this reason it is important that the State's economic model be corrected. The Administration's approach is not consistent with how project economics are evaluated, and I'll expand on this later in my testimony.

To ensure the best result, the logical way forward in our opinion is for AGIA to establish the State's broad key objectives, then allow applicants flexibility so that they can compete to meet those objectives and define the parameters that are necessary to make the project commercially viable. As an illustration of what I am proposing, AGIA could allow the applicant to demonstrate how their proposal encourages exploration and development in Alaska rather than specifying the method of project access and expansion.

If you were to amend AGIA to make it objective driven, it would allow open competition, maximize the number of applicants and allow those applicants to propose innovative solutions to meet the State's needs and open the basin. The State could then evaluate the proposals and select the one that best serves Alaska's needs and assures Alaskans realize the maximum value for their resource. That process would allow ExxonMobil,

the largest leaseholder of gas on the North Slope, to compete under the AGIA process while providing the State complete flexibility on who is chosen to move the Alaska Gas Pipeline Project forward.

To understand why it's important to use broad objectives as opposed to prescribing specific requirements, it is helpful to review project risks and issues surrounding its development that will have to be addressed by an applicant.

PROJECT RISK / PRODUCER CAPABILITIES

The tendency exists for many to underestimate the size, magnitude and risks associated with this project. The Alaska Gas Pipeline Project is a world-scale undertaking with significant risks. In fact, the project would be the largest private investment in North America – significantly larger than most "model" worldwide oil and gas "mega" projects. Let me be clear, this will be a precedent setting global mega-project. As you heard last week from Mr. Fred Rich of Sullivan and Cromwell (Head of Global Project Development and Finance), this project's financing could be many times greater than the largest North American project financing to date (the Alliance pipeline). There is not really another project that compares.

Because of this size, many factors impact commercial viability, including cost and the potential for cost over-runs, gas price, schedule delays, construction conditions, and regulatory and State fiscal uncertainties. Our previous cost estimate of $20 billion (which is in $2001) will be substantially higher due, in part, to increasing steel prices, which have nearly doubled since 2001, and because we are experiencing hyperinflation on industry and construction labor costs. World-wide mega-projects are also placing

pressure on pricing and availability of global materials, and skilled manpower. In addition, as we have observed over many years, natural gas prices remain highly volatile.

The State of Alaska cannot anticipate how individual applicants will view the various risks I have discussed or how applicants may choose to address them. Establishing a set of rigid, prescribed terms in AGIA will not allow the flexibility needed by individual applicants to weigh and manage those risks in a way that maximizes value to the State and the applicant.

HOW PIPELINES ARE FINANCED

The way projects are financed gives some insight into who bears the risks for projects of this type and how these risks are managed. Last week you heard how pipelines are financed from Mr. Rich. Commercially-sound oil, gas, and pipeline projects traditionally have been able to obtain financing if they have strong sponsors with proven track records and the financial strength to both provide upfront lender required sponsor equity and to backstop key project commitments. For the Alaska Gas Pipeline Project, key project commitments take the form of completion support (either a full debt guarantee or additional equity overrun commitments) and firm, long-term gas transportation commitments. Firm transportation commitments are binding obligations made by companies to pay for the cost of reserving long term gas capacity as shippers on a pipeline. These commitments are made during an "open season", which is a period during which any and all prospective gas shippers can make binding commitments for a specific volume of transportation capacity.

As you may recall, Mr. Rich indicated that for a project of this scale and magnitude, financial institutions will require substantial, long-term, firm transportation commitments to provide funding. These commitments must be provided by creditworthy shippers because this tariff stream underpins the debt repayment. Furthermore, lenders not only look at the contractual commitments, but place equal importance on the underlying economics of the project. Any potential reduction in the Producer's netback is a concern to the lender since it increases the likelihood that the integrated project may not be economic, that the transportation charges are not paid, and that as a result the lenders are not repaid. Looking at this another way, the lenders are assessing how effectively the parties taking the risks are managing these risks. They will also want these risks reduced to a minimum to make sure they will get paid back. For this reason they would prefer stable fiscal regimes, project sponsors who have a proven track record of delivering mega projects on time and on budget, project sponsors with ownership in the upstream, and shippers who can support and will honor multi-billion dollar firm transportation agreements.

WHO BEARS PROJECT RISKS

That is why it is so important to understand who bears the project risks. Through the firm transportation commitments, the project development costs and the associated cost over-run risks are ultimately borne by the shippers. For this project, the shippers will be the Producers, and, directly or indirectly, the State or the State's shipper. These firm transportation commitments are valued in the tens of billions of dollars for our company alone, and could be over $100 billion for all the shippers. Shippers must make long-term ship or pay transportation commitments and agree to pay transportation and treating rates that are ultimately based on the final cost of the pipeline and treating

facilities. The only information the shippers will know in advance of making these multi-billion dollar commitments will be a projection of the transportation charges based on the project sponsor's initial estimate of costs. The firm transportation commitments must be paid regardless of whether the shipper making those commitments actually transports gas through its reserved capacity and irrespective of the actual transportation charges. The shipper is also required to pay this reserved capacity commitment even if the market price for the gas is less than the cost of transportation.

For these reasons, the parties taking the risks for a project of this magnitude need to be able to manage those risks. The Producers, as shippers, cannot make firm transportation commitments during an open season unless they are confident the gas pipeline project can be built and operated cost effectively so that producing and shipping gas over the long-term is commercially viable.

INTEGRATED GAS PIPELINE PROJECT ECONOMICS

For this reason, AGIA needs to bring together the upstream and the midstream and provide for an integrated proposal. Any approach that evaluates them separately is flawed. Let me expand on this point. You heard last week that lenders evaluate the upstream very carefully when financing the midstream. The reason is simple – the upstream pays for the midstream. When I say upstream, I'm talking about the revenue generated from production and sale of the gas and liquids through the pipeline project. Without the commitment of capital to the pipeline by a producer-affiliate or the huge financial obligation required for firm transportation commitments to a third-party pipeline, there is no way the transportation system will be built. Thus, any analysis of the project which excludes midstream capital or the firm transportation commitments is not correct.

Lenders and project sponsors do not make that mistake because they recognize that major gas pipeline projects are built on the back of direct capital commitments or, long-term, firm transportation commitments.

Since firm transportation commitments are legally binding commitments that are the backbone of any financing and essential to funding a pipeline, it only makes sense to account for these commitments when evaluating project economics. Surprisingly, the Administration's analysis of the economics fails to incorporate these financial obligations associated with underpinning the pipeline. Let me expand on this point by asking you to think about the economics from a shipper perspective. The shipper can either make the investment in the midstream through one of its pipeline affiliates or make a commitment to a third party to build the pipeline. In the case of making the commitment to a third party, the shipper must pay the third party for the cost of the pipeline plus a return to the pipeline builder for the investment he ultimately made, not what he projected the costs to be when the commitment was made. So in this case the shipper is paying for the ultimate cost of the pipeline plus the profit the pipeline builder requires. When you think about it this way, the economics have to be worse for the shipper when he makes a transportation commitment versus directly investing in the pipeline.

Because the Administration's economic analysis is flawed, the resulting assertion that the producer's stand-alone upstream economics are robust and improved without ownership of the pipeline is absolutely incorrect. Again, the upstream pays for the midstream and it is no more complicated than that.

Since it appears AGIA is based on this flawed economic analysis, it is critical the legislature address this issue and AGIA be modified to recognize who is taking the risk, the shipper. For ExxonMobil any decision to invest will be based on integrated project economics. It only makes sense for the State to evaluate the proposal on an integrated basis as well because the State is in the same position as the producers receiving the bulk of its revenue from the sale of gas. Because we both receive our revenue from the sale of gas, we should be aligned on the best approach for minimizing transportation costs and maximizing netback value.

IMPORTANCE OF STATE / PRODUCER ALIGNMENT AND BENEFITS OF THE PRODUCER PROJECT

Let me now talk about the importance of alignment between the State and the Producers and the benefits of a Producer Project.

Maximizing the value to the State of Alaska and the resource holders means selecting the right design concept for this mega-project and then executing the Project to deliver the lowest possible cost and fastest possible completion. On a project of this size and magnitude, project construction and operating experience should be a significant consideration. Only a limited number of companies have demonstrated the capabilities, financial strength and arctic experience to effectively participate in and manage world-scale mega-projects.

The Producers have mega-project experience on numerous projects world-wide and have demonstrated success in meeting project objectives. A critical component of that experience is the Producers' Arctic experience in Alaska and throughout the world.

ExxonMobil's arctic experience is extensive - over 40 years – with developments in multiple types of arctic environments. Large projects with significant complexity in harsh environments are what we do and we are extremely qualified to take on this work. ExxonMobil's global project development company is unique within industry and leads the industry in project cost and schedule performance.

ExxonMobil has also demonstrated world-class leadership in safety, health and environmental performance. ExxonMobil is a leader in operating efficiency and a pacesetter in operating safety.

In addition to our project and operational excellence, ExxonMobil has the financial strength to make this mega-project a reality. ExxonMobil has consistently maintained one of the strongest financial positions of any company in the world. We are one of just a few public companies to maintain the highest credit rating from Standard and Poor's (AAA) and Moody's (Aaa), and we have done so for each of the last 88 years. Our financial strength minimizes the likelihood that external financing requirements will significantly delay the project timeline, even in times of financial market turmoil.

It is important to remember that the Alaska Gas Pipeline Project is a basin-opening project that will benefit the State and the oil and gas industry in Alaska for decades into the future. Basin-opening projects throughout the world have progressed and been successful when there is alignment between the host government and the leaseholders. The Producers and the State both want a pipeline project to commercialize the known ANS gas resources and open the basin to gas exploration.

We believe a Producer gas pipeline project will result in maximum value to the State and the Producers. The reason is the Producers and the State have maximum incentive to control costs. Low capital and operating costs, which result in lower treating and transportation costs, and access to premium market price, result in higher netback value on the gas. It's important to keep in mind that the State will receive the majority of its revenue from the value of gas sales via revenue received under its lease royalty agreements and from production taxes, which are valued based on the netback received from the gas.

Third-party owners do not share the same incentives in that they actually benefit from increased capital costs.

Based on the demand for workers that this Project will generate, Alaskans are obviously key to successful project execution. Both the State and the Producers want Alaskans to b[illegible]fit from the many job opportunities that will exist.

We believe that financial strength, experience and the ability to get the job done should be critical components of any evaluation of proposals. When you consider carefully the options available, a Producer pipeline will provide maximum value to the State of Alaska.

IMPORTANCE OF PREDICTABLE AND DURABLE FISCAL TERMS

I would now like to talk about fiscal predictability and its importance for a mega-project such as the Alaska Gas Pipeline Project. For ExxonMobil to progress this mega-project and mitigate its inherent risks, we will need to work together with the State on some

very important fiscal issues. Because of the nature and magnitude of the risks associated with this Project, fiscal terms that are predictable and durable are necessary. This is a common thread for any mega-project investments. In all such cases, we are willing to take geologic risks, we are wil .ng to take cost risks, and we are willing to take commodity price risks, but we cannot take the risk of fiscal terms changing. Let me expand on this further. The first two risks, geologic and cost risk are risks for which we have developed an industry leading expertise to manage. This is what we do day after day at ExxonMobil. Market risk is inevitable in a commodity business such as oil and gas and we manage that by attempting to ensure that we deliver those products into the highest value market at the lowest cost. However, the risk of a change in fiscal terms is of a completely different nature and completely outside our control. We must have agreements that will allow us to develop this mega-project under predictable and durable terms, so that we can make an investment decision with an adequate degree of certainty. This does not mean that taxes cannot change over the life of the project. Predictability means that the State's tax and take terms are sufficiently understood that they can be defined and predictably modeled over time for purposes of evaluating the overall project economics. If fiscal terms can be changed in unpredictable ways in the future, then we are not able to make a well founded investment decision on behalf of our shareholders, nor will lenders be as confident in providing financing for a project of this size.

The Alaska Gas Pipeline Project will require massive investments, billions of dollars, to be made over a period of many years before any revenue is generated from those investments. As a result, increases in taxes on oil and gas related activities during the life of the project could significantly impact the commercial viability of the project, offset

the benefits of taking on a project of this magnitude, and could increase lender concern. Because fiscal terms could be modified under the proposed AGIA legislation, it does not provide the fiscal predictability necessary to ensure a commercially viable project.

It is important for the State to recognize that for mega-project developments, governments do grant long term fiscal stability. These contracts include fiscal stability protection that in some cases runs for the length of the contract and in other cases runs for 40 years or more.

AGIA should allow applicants to put forward their best proposal on what is required to make the project commercially viable, which will allow the State the opportunity to consider those proposals that have the best chance of actually delivering an Alaska gas pipeline.

ADDITIONAL FEEDBACK ON AGIA

I would like to now give some specific feedback on AGIA which is based on the conclusions and principles I've mentioned. I will also outline some additional thoughts on how AGIA should be modified to ensure the best chance of a successful result and allow the State to maximize value. As I previously stated, alignment between the State and the leaseholders is essential to a basin opening project of this magnitude. Therefore, establishing the right approach going forward is the most important activity for the project at this time. To be able to calculate the revenue from the upstream we must have clarity on the taxes and royalty from our oil and gas operations and the taxes and royalties must be set at a level that makes the project viable. In order to ensure a viable project from the outset, we believe this must be done at the beginning.

ExxonMobil recognizes the importance to the State, explorers and others of having access to the project so their gas can be treated and transported to markets. To ensure that a project is constructed, it must be commercially attractive to shippers at the time they make their initial firm transportation commitments. Shippers, particularly those who must invest substantially to explore for, develop and produce gas resources, will not be willing to enter into long-term financial commitments for the transportation of gas if they believe there is a substantial likelihood that their initial rates will be significantly increased in the future in order to accommodate expansions.

Under the Alaska Natural Gas Pipeline Act, Congress struck what it determined was the proper balance between encouraging investment by those willing to commit to pay for initial capacity and encouraging exploration by providing an opportunity for future access to the pipeline. Because of the unique nature of the Alaska gas pipeline project, FERC approved unprecedented policies to enable a FERC-mandated expansion to benefit explorers. The issue of how potential future shippers may access initial capacity and future expansion capacity, if needed, should be administered by the FERC for all elements of the project in the United States.

In addition, the pipeline entity should not be required to accept a FERC certificate irrespective of FERC imposed conditions.

Under AGIA, the proposed upstream inducements would require significant modification to ensure a commercially viable project is obtained. In fact, we do not believe it is practical to address these terms in legislation. Therefore, it would be better for AGIA to

not prescribe specific upstream terms and allow applicants to make proposals to address those terms.

AGIA also prescribes activities that must be completed within a specific timeframe or date certain. Setting arbitrary target dates is not consistent with good project management practices. Further, milestones are not necessary if the project is commercially viable. The Producers will progress the project at the maximum prudent pace, consistent with the industry proven "stage-gate" process for project development – there is no reason to do otherwise.

In general, AGIA lacks specifics on key fiscal terms and other requirements. To address these gaps, AGIA gives commissioners broad authority to adopt additional requirements and establish regulations. Not knowing the requirements now creates significant uncertainty.

Finally, because of the complexity and risk associated with this project, the parties must have an efficient and impartial means of handling disagreements when they arise. We believe project related agreements should provide for binding neutral arbitration as the mechanism for resolving disputes. Binding neutral arbitration is widely utilized in U.S. and international commercial agreements and is not a new concept with the State of Alaska. Arbitration is the method used to resolve disputes under the State's Royalty Settlement Agreements.

CONCLUSION

In closing, I would like to reiterate that ExxonMobil is committed to moving the Alaska Gas Pipeline Project forward. However, we cannot move the project forward if it is not commercially viable. AGIA as written does not provide for a commercially viable project. The Administration's stated goal for AGIA is to increase competition through an open and transparent process. However, in its current form, AGIA will result in less competition because it fails to adequately address the issues raised by those parties who will ultimately pay for the project. It also appears AGIA is based on flawed economic assumptions. It is critical that the legislature and administration address these problems in AGIA or we will end up with a process that sets unrealistic expectations and results in disappointment and failure. In addition, the existing prescriptive terms in AGIA will preclude ExxonMobil from being able to make an open, competitive and conforming proposal; thus, the State will be denied the opportunity to even consider terms from the party holding the largest discovered gas resource and has the capability to deliver a successful project.

ExxonMobil possesses the financial strength and project experience required to make this project a success. We are ready to work with the Administration and the Legislature to establish a process that recognizes the integrated nature of the project and mitigates the risks I've discussed to allow the project to progress. We suggest AGIA be amended to provide for a broad objective driven process that sets out what the State wants to achieve and allows each applicant to propose how best to meet those objectives and identify what is required from the State to advance the project. This process will secure more viable applications, create more competition, afford the State the opportunity to secure the most value and actually get the pipeline built. We

are ready to participate in a competitive, open and transparent process as I've described, but unless AGIA is modified we will not be able to participate.

What we are struggling to understand is why the State is insisting on such a prescriptive way forward. AGIA should allow all interested parties to submit a conforming bid so that the people of the State of Alaska have the opportunity to see and compare all of the bids put forward to build the Alaska gas pipeline.

Thank you for your attention and for the opportunity to address this important topic today. I look forward to addressing your questions.

701 minutes 5/2/07
ML

Contractual Commitments

The following table summarizes the Group's principal contractual obligations at December 31, 2003. Further information on borrowings and capital leases is given in Item 18 — Financial Statements — Note 29 on page F-47 and further information on operating leases is given in Item 18 — Financial Statements — Note 17 on page F-29.

Expected payments by period under contractual obligations and commercial commitments	Payments due by period						
	Total	2004	2005	2006	2007	2008	2009 and thereafter
	($ million)						
Borrowings (a)	20,143	9,366	2,674	2,786	1,299	945	3,073
Finance lease obligations	4,634	127	243	248	240	248	3,528
Operating leases	8,115	1,275	1,066	895	799	728	3,352
Decommissioning liabilities	7,504	86	156	173	154	156	6,779
Environmental liabilities	2,430	465	441	402	276	186	660
Pensions (b)	26,682	633	649	652	659	666	23,423
Other post-employment benefits (c)	11,768	242	252	259	263	264	10,488
Unconditional purchase obligations (d)	67,828	45,491	7,076	3,133	1,888	1,655	8,585

(a) Expected payments exclude interest payments on borrowings.

(b) Represents the expected future contributions to funded pension plans and payments by unfunded pension plans.

(c) Represents the expected future payments for postretirement benefits.

(d) Represents any agreement to purchase goods or services that is enforceable and legally binding and that specifies all significant terms. The amounts shown include arrangements to secure long-term access to supplies of crude oil, natural gas, feedstocks and pipeline systems. In addition, the amounts shown for 2004 include purchase commitments existing at December 31, 2003 entered into principally to meet the Group's short term manufacturing and marketing requirements. The price risk associated with these crude oil, natural gas and power contracts is discussed in Item 11 — Quantitative and Qualitative Disclosures about Market Risk on page 170.

The following table summarizes the nature of the Group's unconditional purchase obligations.

Unconditional purchase obligations payments due by period	Payments due by period						
	Total	2004	2005	2006	2007	2008	2009 and thereafter
	($ million)						
Crude oil and oil products	22,043	19,350	344	452	422	374	601
Natural gas	19,439	13,189	2,575	1,141	489	398	1,647
Chemicals and other refinery feedstocks	10,049	2,277	1,666	753	563	545	4,245
Utilities	11,612	9,622	1,231	289	62	54	354
Transportation	2,814	738	510	365	247	204	750
Use of facilities and services	1,871	315	250	133	105	80	988
Total	67,828	45,491	7,076	3,133	1,888	1,655	8,585

for
BP
20(f)

CDP_243768

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- Other. At December 31, 2003, we had guarantees of approximately $340 million outstanding for our portion of other joint-venture debt obligations, which have terms of up to 22 years. Included in these outstanding guarantees was $114 million associated with the Polar Lights Company joint venture in Russia. Payment will be required if a joint venture defaults on its debt obligations.

Capital Requirements

For information about our capital expenditures and investments, see "Capital Spending" below.

Our balance sheet debt at December 31, 2003, was $17.8 billion. This reflects debt reductions of approximately $4.8 billion during 2003, including accounting changes that increased balance sheet debt approximately $2.8 billion as a result of the adoption of FIN 46. See Note 2—Changes in Accounting Principles and Note 11—Debt, in the Notes to Consolidated Financial Statements, for additional information.

During 2003, we reduced our commercial paper balance outstanding from $1.5 billion at December 31, 2002, to $709 million at December 31, 2003. In 2003, we paid off the following notes and debt facilities as they were called or matured and funded the payments with cash from operating activities and proceeds from asset dispositions:

- $250 million 8.49% Notes due 2023, at 104.245 percent;
- $150 million 8.25% Mortgage Bonds due May 15, 2003;
- $250 million 7.92% Notes due in 2023, at 103.96 percent;
- $250 million 7.20% Notes due 2023, at 103.60 percent;
- $100 million 6.65% Notes that matured on March 1, 2003;
- $163 million SRW Cogeneration Limited Partnership note;
- $500 million Floating Rate Notes due April 15, 2003;
- $98 million Tosco Trust 2000-E 8.78% Senior Secured Notes due 2010;
- $245 million Tosco Trust 2000-E 8.58% Senior Secured Notes due 2010;
- $194 million Arctic Funding, Limited Partnership 6.85% Senior Secured Note due 2011;
- $100 million of floating rate aviation equipment lease obligations having a final maturity in 2004;
- $489 million of fixed and floating rate ocean vessel lease obligations having final maturities from 2004 to 2005; and
- $1,150 million of floating rate marketing lease obligations having maturities from 2003 to 2006.

In October and November 2003, we executed certain interest rate swaps that had the effect of converting $1.5 billion of debt from fixed to floating rate. These swaps qualify for hedge accounting under SFAS 133, "Accounting for Derivative Instruments and Hedging Activities."

Also during 2003, we issued $79.5 million of tax-exempt bonds and assumed an additional amount of $20 million.

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Contractual Obligations

The following table summarizes our aggregate contractual fixed and variable obligations as of December 31, 2003:

	Millions of Dollars				
	Payments Due by Period				
At December 31, 2003	Total	Up to 1 Year	1-3 Years	3-5 Years	After 5 Years
Debt obligations*	$ 17,720	1,434	3,110	1,202	11,974
Capital lease obligations	60	6	12	38	4
Total debt	17,780	1,440	3,122	1,240	11,978
Operating leases	[illegible]	871	810	[illegible]	3,373
Purchase obligations**	58,231	19,972	4,869	3,915	29,475
Other long-term liabilities***					
Asset retirement obligations	2,685	61	242	364	2,018
Accrued environmental costs	1,119	160	304	138	517
Total	$ 82,888	22,084	9,347	6,276	45,181

*Total debt excluding capital lease obligations. Includes net unamortized premiums and discounts.

**Represents any agreement to purchase goods or services that is enforceable and legally binding and that specifies all significant terms. The majority of the purchase obligations are market-based contracts. Includes: (1) our commercial activities of $23.0 billion, of which $11.1 billion are primarily related to the supply of crude oil to our refineries and the optimization of the supply chain, $7.6 billion primarily related to the supply of unfractionated NGLs to fractionators, optimization of NGL assets, and for resale to customers, $4.4 billion primarily related to natural gas for resale to customers, $1.7 billion of futures, and $217 million related to the purchase side of exchange agreements; (2) $23.3 billion of purchase commitments for products, mostly natural gas and natural gas liquids, from CPChem over the remaining term of 97 years; and (3) purchase commitments for jointly owned fields and facilities where we are the operator, of which some of the obligations will be reimbursed by our co-owners in these properties. Does not include: (1) purchase commitments for jointly owned fields and facilities where we are not the operator; (2) our agreement to purchase up to 104,000 barrels per day of Petrozuata crude oil for a market-based formula price over the term of the Petrozuata joint venture (about 35 years) in the event that Petrozuata is unable to sell the production for higher prices; and (3) an agreement to purchase up to 165,000 barrels per day of Venezuelan Merey, or equivalent, crude oil for a market price over a remaining 16-year term if a variety of conditions are met.

***Does not include: (1) Taxes—the company's consolidated balance sheet reflects liabilities related to income, excise, property, production, payroll and environmental taxes. We anticipate the current liability of $2,676 million for accrued income and other taxes will be paid in the next year. We have other accrued tax liabilities whose resolution may not occur for several years, so it is not possible to determine the exact timing or amount of future payments. Deferred income taxes reflect the net tax effect of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for tax purposes; (2) Pensions—for the 2004 through 2008 time period, we expect to contribute an average of $400 million per year to our qualified and non-qualified pension and postretirement medical plans in the United States and an average of $100 million per year to our non-U.S. plans, which are expected to be in excess of required minimums in many cases. Our required minimum funding in 2004 is expected to be $95 million in the United States and $75 million outside the United States; (3) Severance—we have expected severance payments of $109 million in 2004 and $1 million in 2005; and (4) Interest—we anticipate payments of $1,046 million in 2004, $2,012 million for the period 2005 through 2006, $1,708 million for the period 2007 through 2008, and $8,955 million for the remaining years to total $13,721 million.

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Capital Spending

Capital Expenditures and Investments

	Millions of Dollars			
	2004 Budget	2003	2002	2001
E&P				
United States—Alaska	$ 656	878	706	963
United States—Lower 48	763	848	699	189
International	3,939	3,998	2,071	1,162
	5,358	4,745	3,476	2,314
Midstream	15	19	5	—
R&M				
United States	1,019	860	476	473
International	246	319	164	5
	1,265	1,179	640	478
Chemicals	—	—	60	4
Emerging Businesses	62	284	112	—
Corporate and Other*	167	184	83	44
	$ 6,867	6,169	4,388	3,016
United States	$ 2,574	2,493	2,063	1,849
International	4,243	3,676	2,345	1,167
	$ 6,812	6,169	4,388	3,016
Discontinued operations	$ —	236	57	65

* Excludes discontinued operations.

Our capital spending for continuing operations for the three-year period ending December 31, 2003, totaled $13.6 billion. Spending was primarily focused on the growth of our E&P business, with 78 percent of total spending for continuing operations in this segment. The capital programs of DEFS, our gas gathering, processing and marketing joint venture company, and CPChem, our chemicals joint venture company, are intended to be self-funding, and are not reflected in the amounts above.

Including about $133 million in capitalized interest and $400 million that will be funded by minority interests in the Bayu-Undan gas export project, our Board has approved $6.9 billion for capital projects and investments for continuing operations in 2004, a 12 percent increase over our 2003 capital spending of $6.2 billion. We plan to direct 78 percent of our 2004 capital budget to E&P and 19 percent to R&M. The remaining budget will be allocated to our emerging businesses, mainly power generation, and general corporate projects, with a majority related to global integration of systems. Thirty-eight percent of the budget is targeted for projects in the United States.

E&P

Capital spending for continuing operations for E&P during the three-year period ending December 31, 2003, totaled $10.5 billion. The expenditures over the three-year period supported several key exploration and development projects including:

- National Petroleum Reserve-Alaska (NPR-A) and satellite field prospects on Alaska's North Slope;

from ConocoPhillips 2003 10(K)

CDP_243769

from ExxonMobil 2003 10(K)

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MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

company benefit plans and programs and to reduce the number of shares outstanding. Shares outstanding were reduced from 6,700 million at the end of 2002 to 6,568 million at the end of 2003. Purchases were made in both the open market and through negotiated transactions. Purchases may be increased, decreased or discontinued at any time without prior notice.

2002

Cash used in financing activities was $11.4 billion, down $3.7 billion, reflecting lower debt reductions. Dividend payments on common shares increased to $0.92 per share from $0.91 per share and totaled $6.2 billion, a payout of 54 percent. Total consolidated short-term and long-term debt was comparable at $10.7 billion. Shareholders' equity increased by $1.4 billion to $74.6 billion.

During 2002, Exxon Mobil Corporation purchased 127 million shares of its common stock for the treasury at a gross cost of $4.8 billion. These purchases were to offset shares issued in conjunction with company benefit plans and programs and to reduce the number of shares outstanding. Shares outstanding were reduced from 6,809 million at the end of 2001 to 6,700 million at the end of 2002. Purchases were made in both the open market and through negotiated transactions.

Commitments

Set forth below is information about the corporation's commitments outstanding at December 31, 2003. It provides data for easy reference from the consolidated balance sheet and from individual notes to the consolidated financial statements.

		Payments Due by Period				
Commitments	Note Reference Number	2004	2005-2008	2009 and Beyond	2003 Total Amount	2002 Total Amount
			(millions of dollars)			
Long-term debt [1]	15	$ —	$ 877	$3,879	$4,756	$6,655
– Due in one year [2]		1,903	—	—	1,903	884
Asset retirement obligations [3]	10	125	461	2,854	3,440	3,454
Pension obligations [4]	18	1,180	1,720	4,937	7,837	9,385
Operating leases [5]	11	1,299	2,730	2,160	6,189	6,945
Unconditional purchase obligations [6]	17	520	1,703	2,563	4,786	3,649
Take-or-pay obligations [7]		833	1,874	1,340	4,047	3,475
Firm capital commitments [8]		4,251	2,173	595	7,019	8,449

This table excludes commodity purchase obligations for which an active, highly-liquid market exists and which are expected to be re-sold shortly after purchase. Inclusion of such amounts would not be meaningful in assessing liquidity and cash flow, since such purchases will be offset in the same periods by cash received from sales.

Notes:

(1) Includes capitalized lease obligations of $370 million. Long-term debt amounts exclude the corporation's share of equity company debt, which is included in the calculation of return on average capital employed as shown on page 27.

(2) The amount due in one year is included in notes and loans payable of $4,789 million (note 7).

(3) The discounted present value of upstream asset retirement obligations, primarily asset removal costs at the completion of field life.

(4) The amount by which accumulated benefit obligations (ABO) exceeded the fair value of fund assets for certain U.S. and non-U.S. plans at year end (note 18 on page 65). For funded pension plans, this difference was $3.0 billion at December 31, 2003 (U.S. $0.5 billion, non-U.S. $2.5 billion). For unfunded plans, this was the ABO amount of $4.9 billion (U.S. $1.0 billion, non-U.S. $3.9 billion). The payments by period include expected contributions to funded pension plans in 2004 and estimated benefit payments for unfunded plans in all years.

(5) Minimum commitments for operating leases, shown on an undiscounted basis, cover drilling equipment, tankers, service stations and other properties.

(6) Unconditional purchase obligations (UPOs) are those long-term commitments that are noncancelable and that third parties have used to secure financing for the facilities that will provide the contracted goods or services. The undiscounted obligations of $4,786 million mainly pertain to pipeline throughput agreements and include $1,887 million of obligations to equity companies. The present value of the total commitments, excluding imputed interest of $1,543 million, was $3,243 million.

(7) Take-or-pay obligations are noncancelable, long-term commitments for goods and services other than unconditional purchase obligations. The undiscounted obligations of $4,047 million mainly pertain to transportation, refining and natural gas purchases and include $622 million of obligations to equity companies. The present value of the total commitments, excluding imputed interest of $663 million, totaled $3,384 million.

(8) Firm commitments related to capital projects, shown on an undiscounted basis, totaled approximately $7.0 billion at the end of 2003, compared with $8.4 billion at the end of 2002. These commitments were predominantly associated with upstream projects outside the U.S., of which the largest single commitment outstanding at the end of 2003 was $1.6 billion associated with the development of crude oil and natural gas resources in Malaysia. The corporation expects to fund the majority of these commitments through internal cash flow.

Guarantees

	Equity Company Obligations	Other Third Party Obligations	Total
		(millions of dollars)	
Guarantees of excise taxes/customs duties under reciprocal arrangements	$ —	$ 983	$ 983
Other guarantees	1,872	424	2,296
Total	$ 1,872	$ 1,407	$3,279

The corporation and certain of its consolidated subsidiaries were contingently liable at December 31, 2003 for $3,279 million, primarily relating to guarantees for notes, loans and performance under contracts (note 17). This included $983 million representing guarantees of non-U.S. excise taxes and customs duties of other companies, entered into as a normal business practice, under reciprocal arrangements. Also included in this amount were guarantees by consolidated affiliates of $1,872 million, representing ExxonMobil's share of obligations of

Presentation to the Alaska Legislature House Finance Committee May 2, 2007

Dan E. Dickinson

CPA, CMA

for minutes file 5/2/07 5/3/07 5/2/07

- How is gas generally taxed under the PPT? What are the PPT credit implications of gasline work?

- Same as oil (almost) – on net value
- Investment downstream of the point of production not eligible for credits

How is gas taxed under the PPT

- 43.55.011
- (e) 22.5% of net value
- (f) North Slope floor triggered by oil price
- (g) & (h) Progressivity triggered by single taxpayer net value
- (i) Private royalty 1.67% for gas – 1/3 of oil
- (j) Cook Inlet Ceiling

AS 43.55.011 (e) 22.% of net value

- Total upstream costs are deducted from the revenue streams from oil and gas sales.

- Gas Revenue Exclusion (GRE) mechanism discussed in 2006 is an administratively simple way of adjusting the effective rate without changing the nominal rate or making lots of allocations.

43.55.011(f) North Slope floor triggered by oil price

- Alternative floor just applicable to North Slope Oil and Gas is triggered by oil price.
  - Consider future if Prudhoe Bay is producing 250,000 bbls oil and 3 bcf of gas.
  - If the heating value is 1,000,000 btu per mcf, that translates to the equivalent of 500,000 bbls a day – so 1/3 of the field's production will be used to set the trigger.

[redacted]

- Question 3. How does PPT progressivity work on gas and what is it's link to oil?

AS 43.55.011(g) & (h) Progressivity triggered by single taxpayer net value

- Progressivity is determined for each taxpayer on its total mix of oil and gas and all upstream costs
- Calculated on a monthly basis – monthly upstream costs are 1/12 of total annual costs
- Example – Next slide
  - Prices April 27 2007,
  - 1,000 btu per mcf,
  - equal mix of boe gas and oil

AS 43.55.011(g) & (h) progressivity triggered by single taxpayer net value

	Oil		Gas		Gas BOE		Taxpyr Ave
Dest Price	63.76		7.32				
Downstream Adj	(5.00)		(3.00)				
Gross Value	58.76		4.32	6.00	25.92		
Upstream Adj	(7.00)				(7.00)		
Net Value	51.76				18.92		35.34
.011(h) limit	(40.00)				(40.00)		(40.00)
Price Index	11.76				N/a		N/a
.011(g) factor	0.0025				0.0025		0.0025
Progressivity %	2.940%				N/a		N/a

Dollar/bbl progressivity Charge at various Destination values and net deductions

Per barrel Progressivity Charge

Per Barrel Costs	Monthly Average Destination Value per bbl in Dollars						
	50	55	60	65	70	75	80
5	0.56	1.25	2.06	3.00	4.06	5.25	6.56
6	0.44	1.10	1.89	2.80	3.84	5.00	6.29
7	0.32	0.96	1.72	2.61	3.62	4.76	6.02
8	0.21	0.82	1.56	2.42	3.41	4.52	5.76
9	0.10	0.69	1.40	2.24	3.20	4.29	5.50
10		0.56	1.25	2.06	3.00	4.06	5.25
11		0.44	1.10	1.89	2.80	3.84	5.00
12		0.32	0.96	1.72	2.61	3.62	4.76
13		0.21	0.82	1.56	2.42	3.41	4.52
14		0.10	0.69	1.40	2.24	3.20	4.29
15			0.56	1.25	2.06	3.00	4.06
16			0.44	1.10	1.89	2.80	3.84
17			0.32	0.96	1.72	2.61	3.62
18			0.21	0.82	1.56	2.42	3.41
19			0.10	0.69	1.40	2.24	3.20
20				0.56	1.25	2.06	3.00

AS 55.43.011(i) Private Royalty 1.67% of gross for gas

- This is one third the rate for oil which is 5% of gross.

AS 43.55.011(j) Cook Inlet Ceiling

- No direct effect on North Slope gas
- Expires in 2022
- If gas line is built from North Slope to Cook Inlet may want to consider effect of differential rates of taxation
- Ceiling potentially different for each producer:
  - Average (15 AAC 55.440) 4.947% of $3.585 per mcf.

- Are PPT gas credits applicable to the GTP in the AGIA bill?

- Under PPT – the GTP is not eligible for credits.

Only Upstream Costs Qualify as Credits

- AS 43.55.023 (a) "…may take a tax credit for a qualified capital expenditure… in the amount of 20 percent of that expenditure;"

- AS 43.55.023 (k)"…'qualified capital expenditure'…means…an expenditure that is a lease expenditure under AS 43.55.165 and is…treated as a capitalized expenditure under 26 U.S.C. (Internal Revenue Code)

Only Upstream Costs Qualify as Credits

- AS 43.55.165 (a) "…a producer's lease expenditures for a calendar year are the ordinary and necessary costs upstream of the point of production of oil and gas …and that are the direct costs of exploring for developing, or producing oil or gas…

Where is the point of Production?

- In AS 43.55.900
- (21) gas processing
- (23) gas treatment
- (27) point of production
- Are defined so that gas processing is upstream of the point of production and gas treatment is downstream of the point of production.

PPT Definitions: Point of Production

- AS 43.55.011(27) "point of production" means
- (A) for oil…
- (B) for gas, other than gas described in (c) of this paragraph that is
- (i) not subjected to or recovered by mechanical separation or run through a gas processing plant, the first point where the gas is accurately metered;
- (ii) subjected to or recovered by mechanical separation but not run through a gas processing plant, the first point where the gas is accurately metered after completion of mechanical separation;

PPT Definitions: Point of Production

- AS 43.55.011(27) "point of production" means
- (B) for gas…
- (iii) run through a gas processing plant, the first point where the gas is accurately metered downstream of the plant;
- (C) for gas run through an integrated gas processing plant and gas treatment facility that does not accurately meter the gas after the gas processing and before the gas treatment, the first point where the gas processing is completed or where gas treatment begins, whichever is further upstream.

PPT Definitions: Gas Processing

- AS 43.55.011 (21) "gas processing"
- (A) means processing a gaseous mixture of hydrocarbons
- (i) by means of absorption, adsorption, externally applied refrigeration, artificial compression followed by adiabatic expansion using the Joule-Thomson effect, or another physical process that is not mechanical separation; and
- (ii) for the purpose of extracting and recovering liquid hydrocarbons [producing ngls/oil];
- (B) does not include gas treatment

PPT Definitions: Gas Treatment

- AS 43.55.011 (23) "gas treatment"
- (A) means conditioning gas and removing from gas nonhydrocarbon substances for the purpose of rendering the gas acceptable for tender and acceptance into a gas pipeline system.
- (B) includes incidentally removing liquid hydrocarbons from the gas

PPT Definitions: Gas Treatment

- AS 43.55.011 (23) "gas treatment" (cont.)
- (C) does not include
  - (i) dehydration required to facilitate the movement of gas from the well to the point where gas processing takes place;
  - (ii) the scrubbing of liquids from gas to facilitate gas processing.

Under Current law:

- Gas Processing
- Starts with gaseous mixture of hydrocarbons, and produces natural gas liquids and gas by removing the hydrocarbon iiquids.
- Gas treatment
- Starts with produced gas and removes nonhydrocarbons (including incidental hydrocarbons) to prepare the gas for tender to the pipeline. Nothing is produced.

AGIA Definitions: Gas Processing

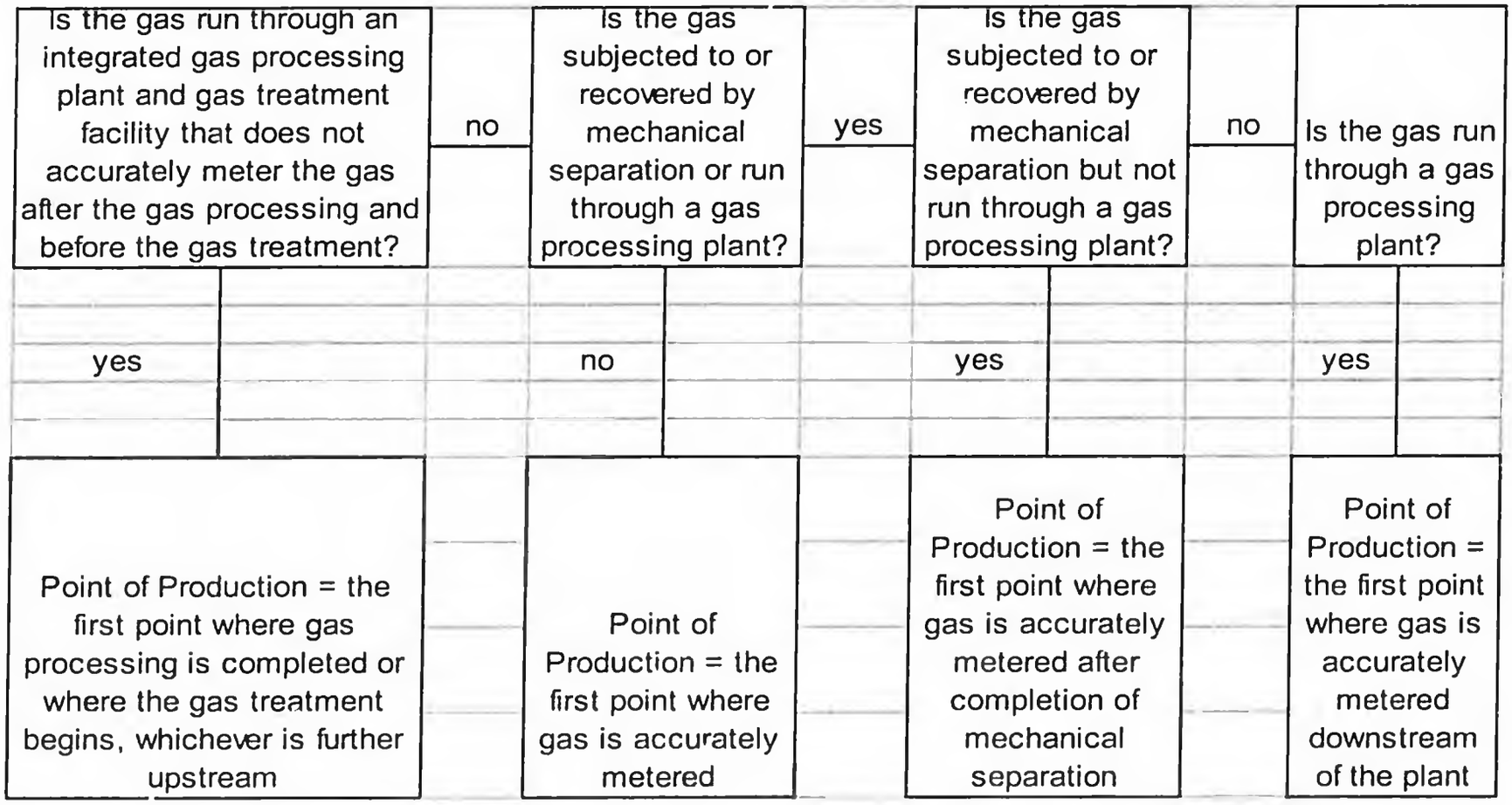
- AS 43.55.900 (7) "gas processing" means the treatment of gas downstream of the point of production to extract natural gas liquids. CSHB 177(RES)
- AS 43.55.900 (7) "gas processing" means post-production treatment of gas to extract natural gas liquids. CSSB 104(JUD)

AGIA Definitions: Gas Processing

- Suggested Definition

- AS 43.55.900 (7) "gas processing" has the same meaning as "gas processing" in AS 43.55.900 (21)

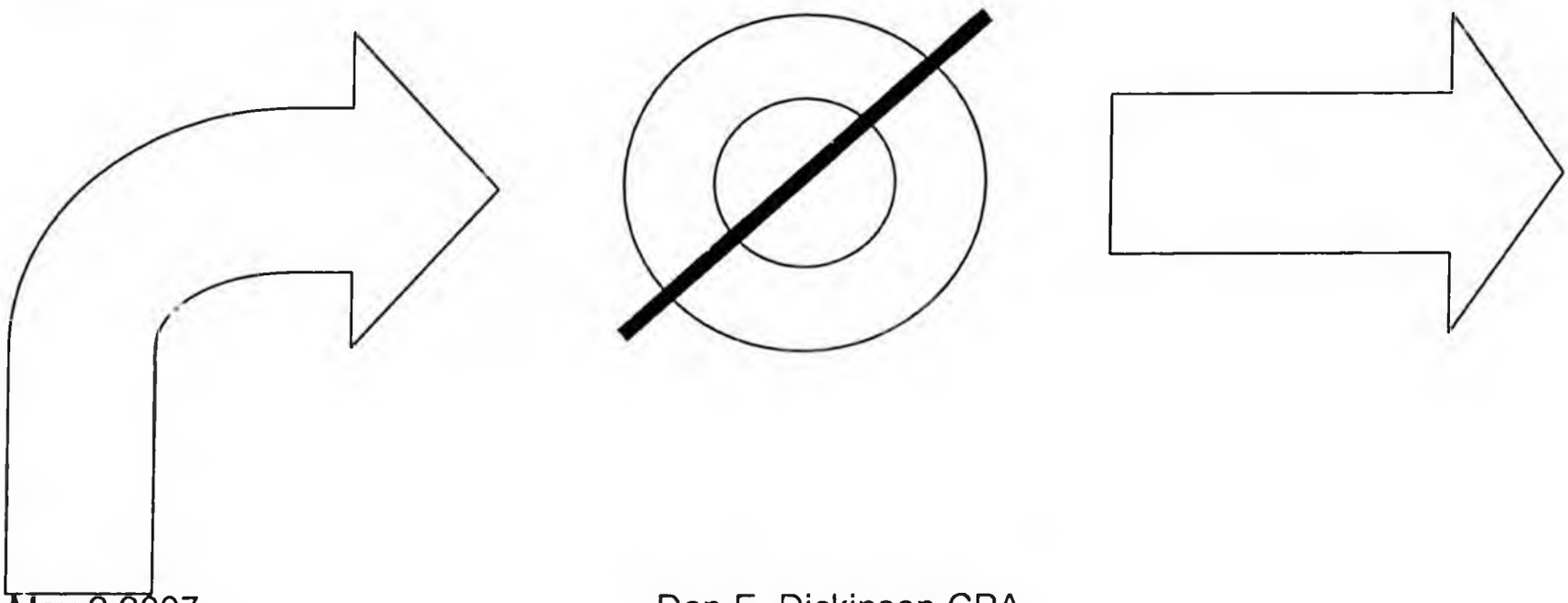
PPT Point of Production for Gas



Gas Point of Production

Gas not run through a gas processing point or subject to mechanical separation

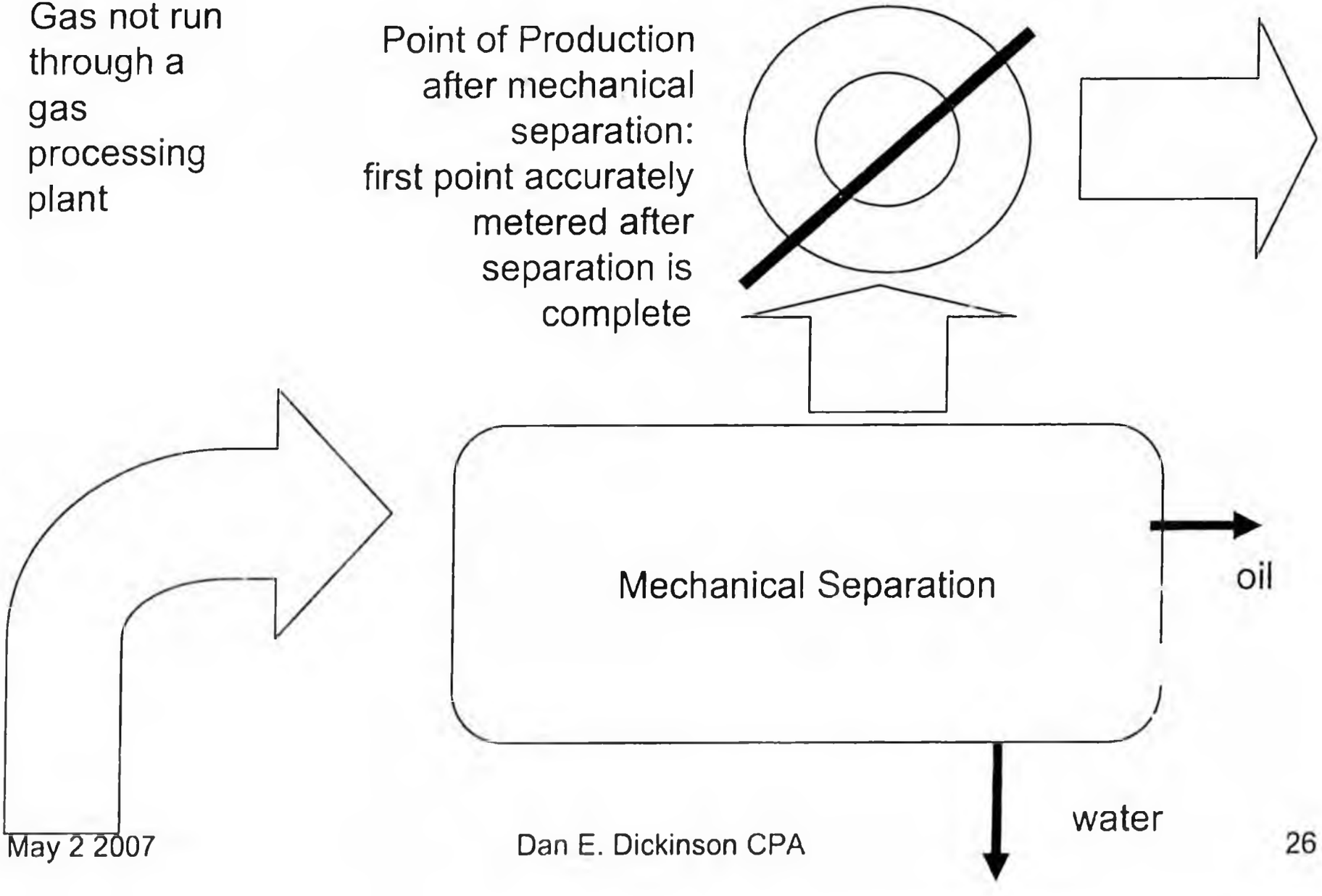
Point of Production: first point accurately metered



Gas Point of Production

Gas not run through a gas processing plant

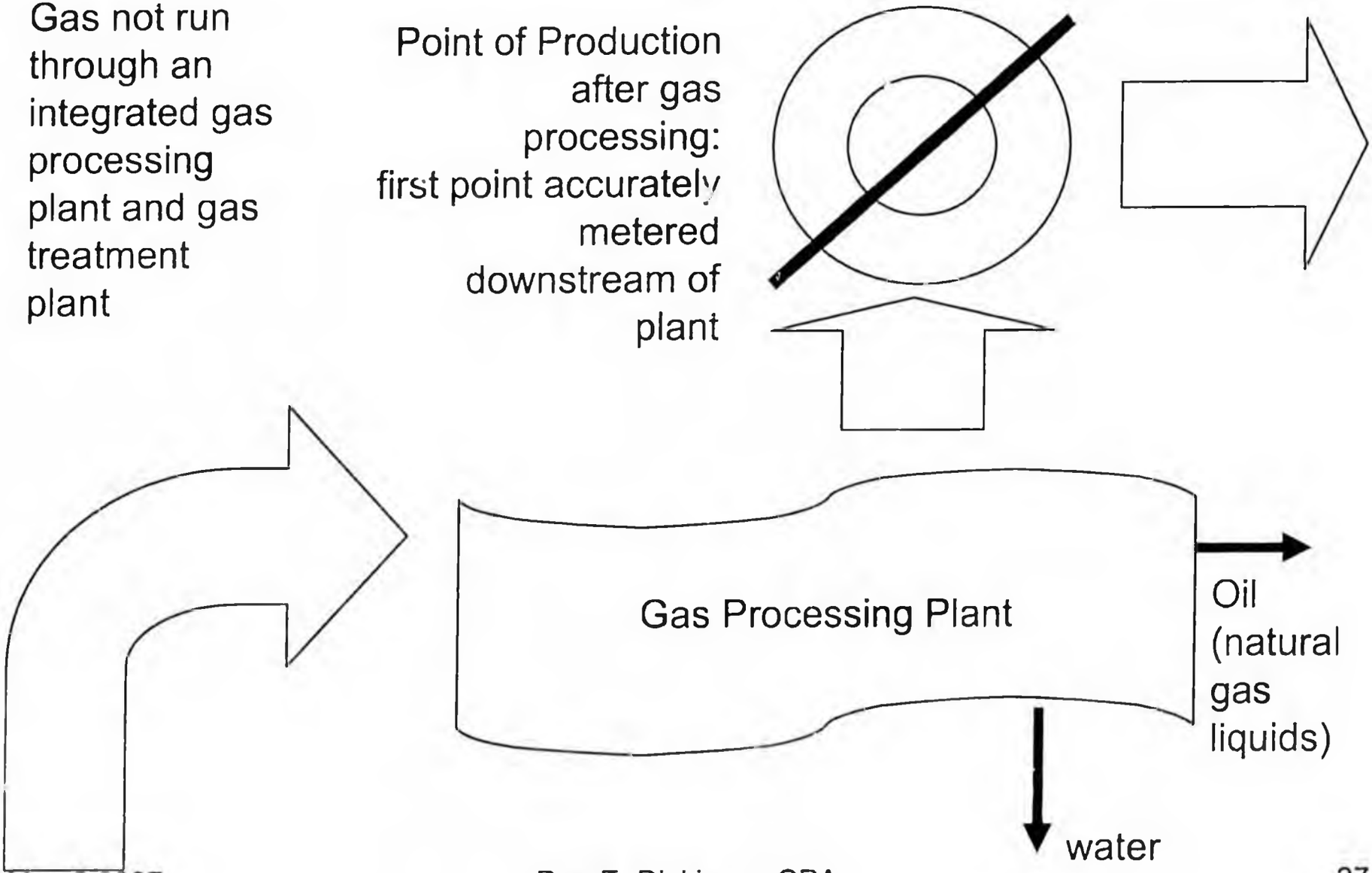
Point of Production after mechanical separation: first point accurately metered after separation is complete



Gas Point of Production

Gas not run through an integrated gas processing plant and gas treatment plant

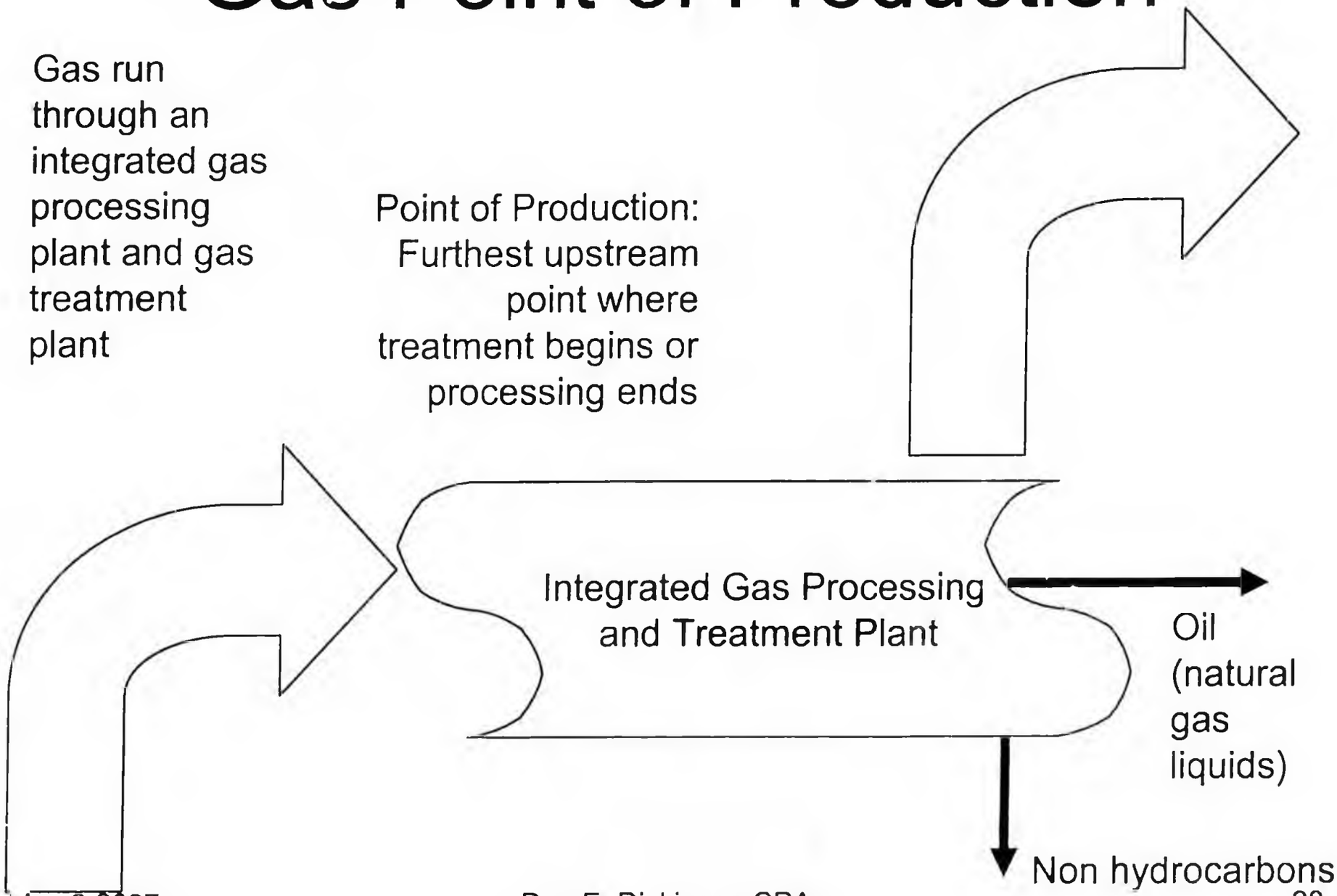
Point of Production after gas processing: first point accurately metered downstream of plant



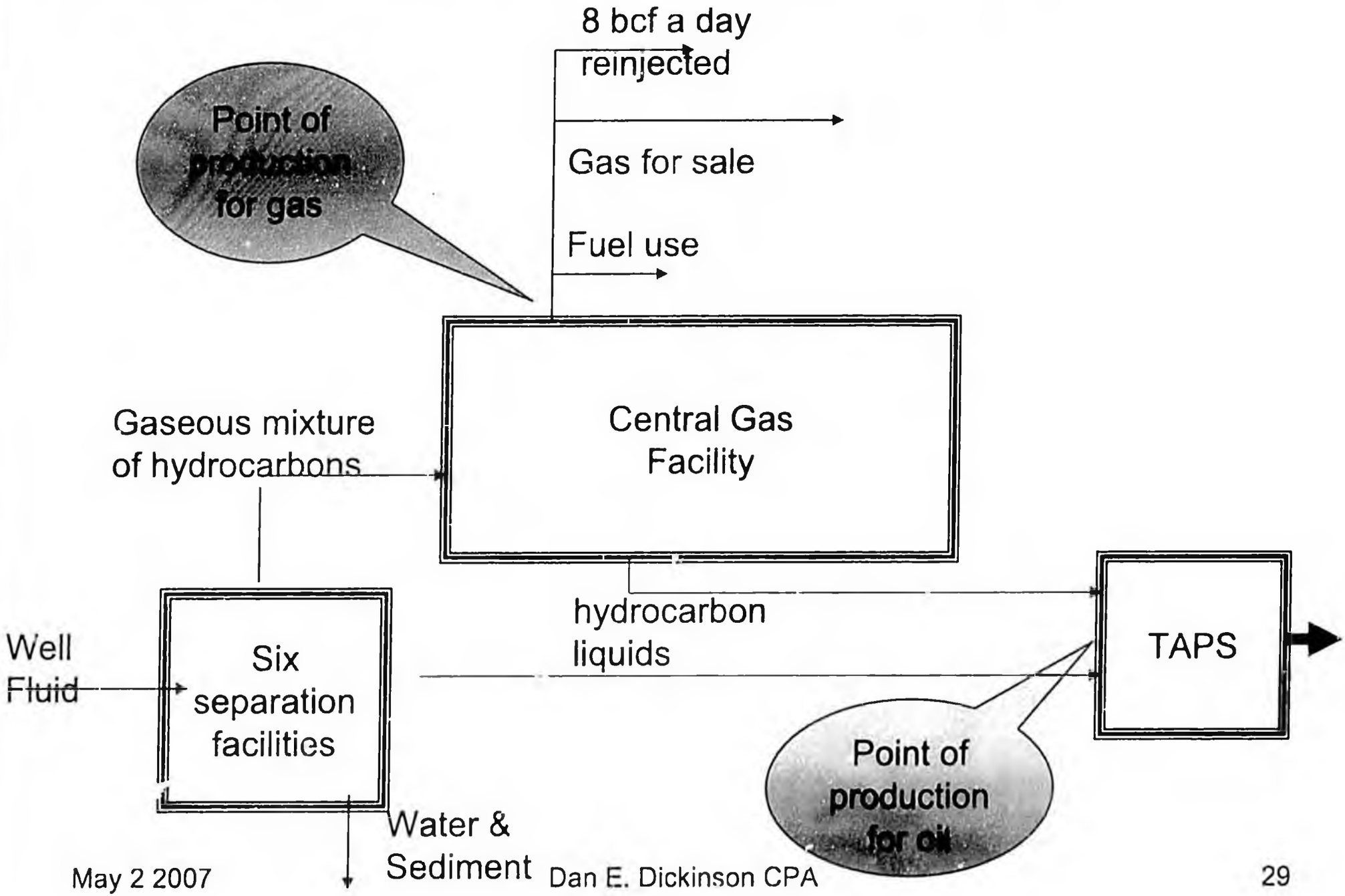
Gas Point of Production

Gas run through an integrated gas processing plant and gas treatment plant

Point of Production: Furthest upstream point where treatment begins or processing ends



Prudhoe Bay: Point of Production under the PPT



North Slope Central Gas Facility

- On the Alaska North Slope the Central Gas Facility is a gas processing plant, which sends natural gas liquids which are produced at the TAPS inlet:

- AS 43.55.009 (27) "point of production" means (A) for oil … the device through which the oil enters into the facilities of a carrier pipeline…in a condition of pipeline quality…"
- AS 43.55.009 (10) "oil" means (A) crude petroleum oil: and (b) all liquid hydrocarbons that are recovered…by gas processing in a gas processing plant.

North Slope Central Gas Facility

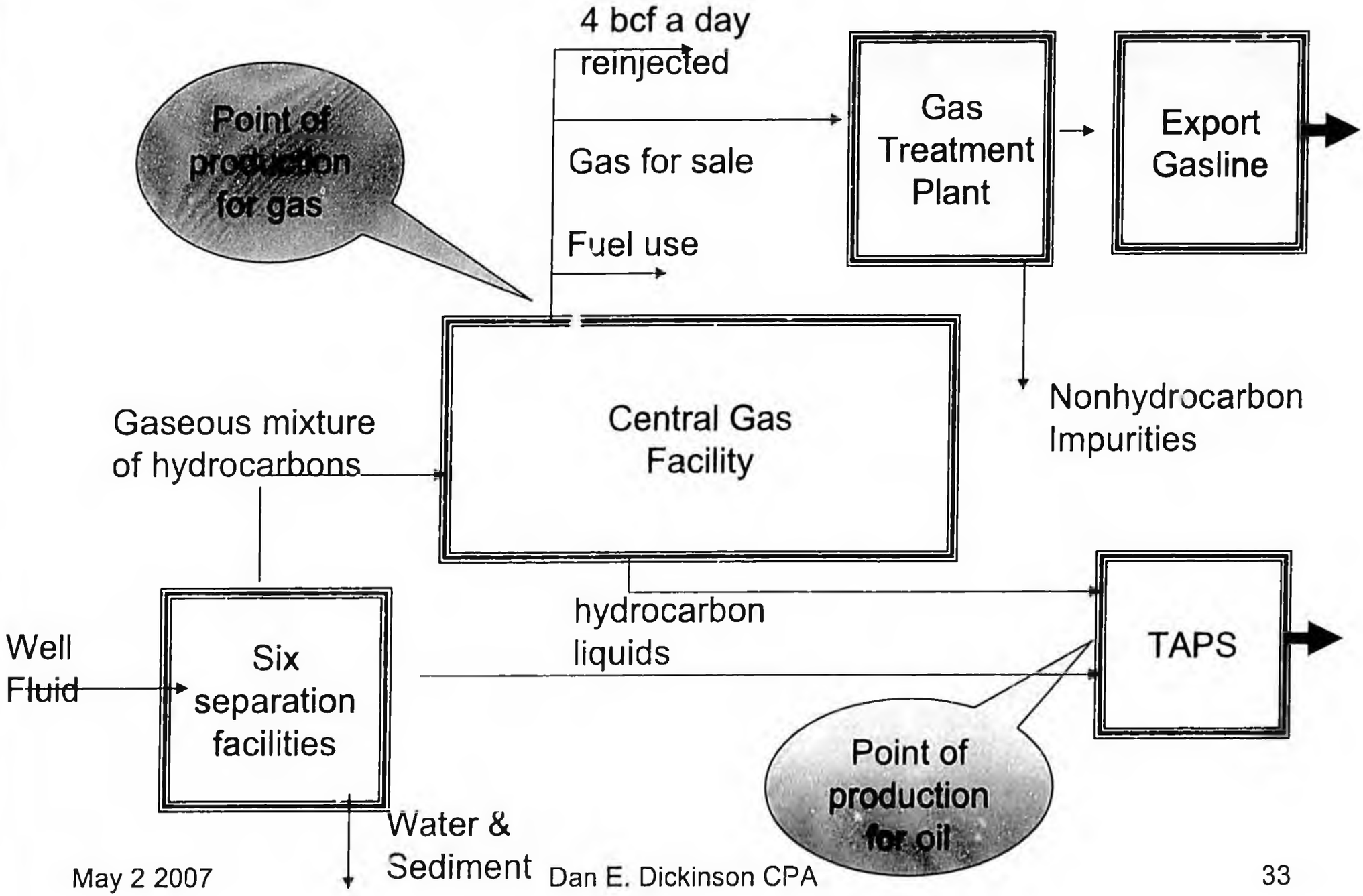
- On the Alaska North Slope the Central Gas Facility is a gas processing plant,

- AS 43.55.020 (e) "… gas used in the operation of a lease or property in the state in drilling for or producing oil or gas or for repressuring…is not considered…as … gas produced from a lease or property."

Answer to the Question:

- If CGF remains a separate plant and sends gas to a Gas Treatment Plant (GTP), gas would be produced as it is metered out of plant. The GTP would be downstream of the point of production for the gas and thus associated operating and capital costs would not qualify as lease expenditures under AS 43.55.165 (a) nor would capital costs qualify for credit treatment under AS 43.55023 (a).

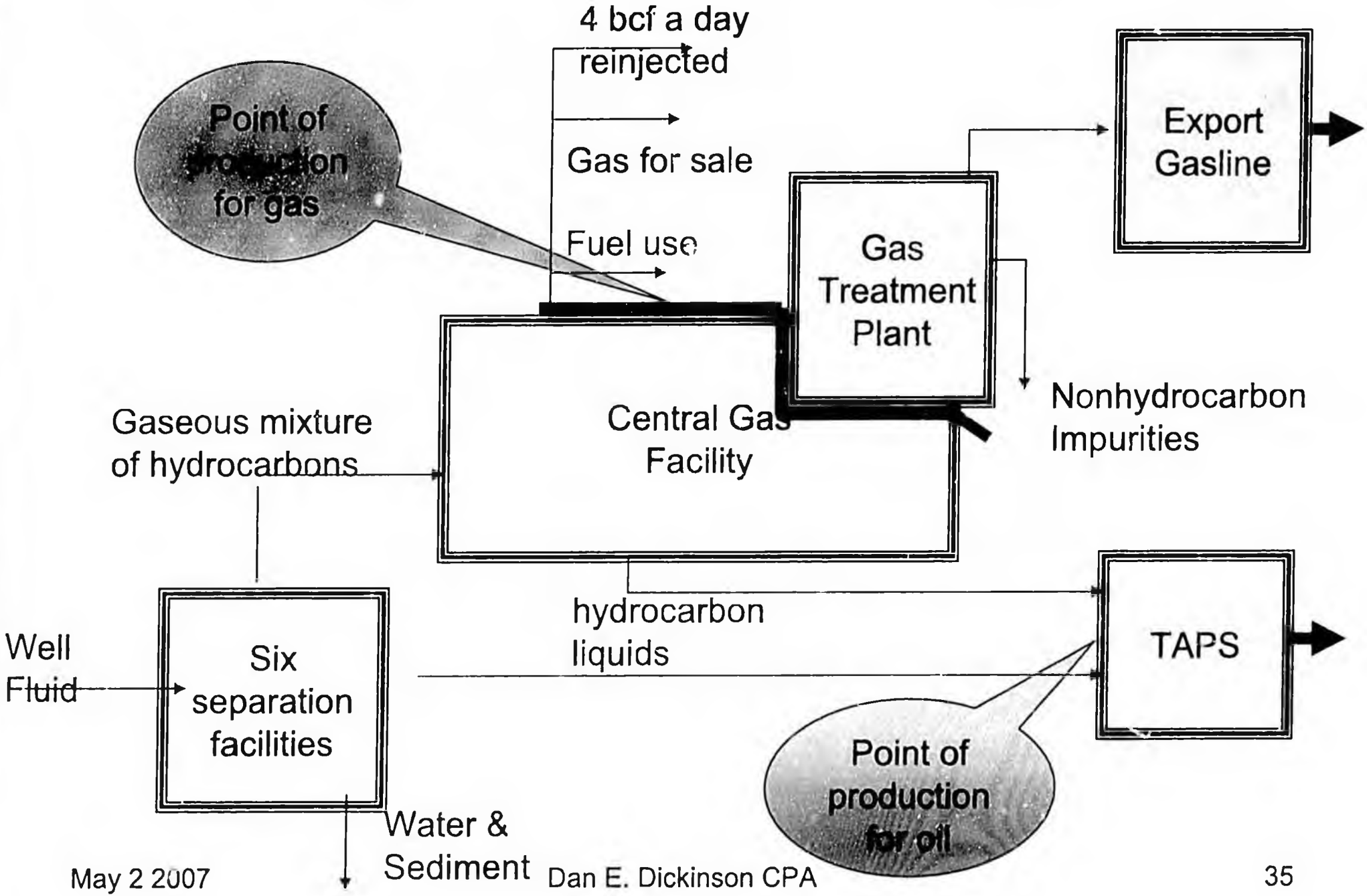
Prudhoe Bay: Point of Production under the PPT with a GTP



Answer to the Question:

- If CGF becomes integrated into a Gas Treatment Plant (GTP) (produced gas is not metered), then the gas would be produced within that integrated facility, at the furthest point upstream of the beginning of gas treatment or the end of gas processing. If the plants are integrated, the risk is that some gas processing will move downstream of the point of production, not that gas treatment will move upstream of the point of production.

Prudhoe Bay: Point of Production under the PPT w/integrated GTP



- We are trying to determine how attractive an investment this pipeline is. Antony Scott, Commercial Analyst, DNR, Oil and Gas, in his April 11, 2007 presentation shows that using the IRR metric this project can have very high rates of return, particularly with a third party line. However we believe he does not include the cost of shippers' firm transportation commitments in his numbers when comparing an independent pipeline with a producer owned pipeline. How might this affect his results?

Firm Transportation

- Shipper makes a Firm Transportation commitment (FT) to pay the capital portion of the tariff whether it uses the pipeline or not.
- It is that financial commitment that underwrites the pipeline:
  - Required by FERC before approving a project
  - Required by lenders before lending money to a project.

Producers' returns as both shippers + pipeline owners

AGIA
The Alaska Gasline Inducement Act

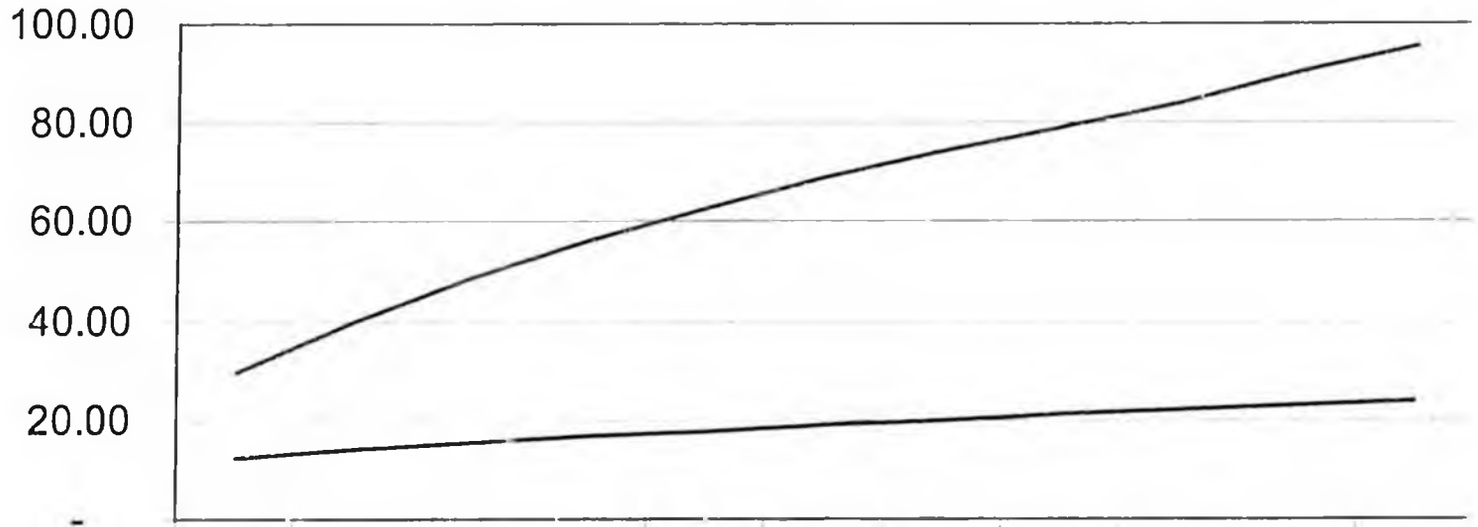
	NPV	IRR	P/I	NPV per BOE
$3.50	3.0	12.6%	1.3	$0.37
$4.00	5.0	14.0%	1.4	$0.60
$4.50	6.9	15.4%	1.6	$0.83
$5.00	8.7	16.7%	1.7	$1.06
$5.50	10.6	17.9%	1.9	$1.28
$6.00	12.4	19.0%	2.0	$1.50
$6.50	14.2	20.1%	2.2	$1.72
$7.00	16.0	21.1%	2.3	$1.93
$7.50	17.7	22.1%	2.5	$2.14
$8.00	19.3	23.0%	2.6	$2.33
$8.50	20.8	23.9%	2.7	$2.51

Producer Upstream Returns
Base case cost = $20.5B

AGIA
The Alaska Gasline Inducement Act

	NPV	IRR	P/I	NPV per BOE
$3.50	4.1	29.8%	3.2	$0.49
$4.00	6.1	39.7%	4.3	$0.74
$4.50	8.1	48.7%	5.3	$0.98
$5.00	10.1	56.3%	6.4	$1.22
$5.50	12.1	62.9%	7.5	$1.46
$6.00	14.0	68.9%	8.5	$1.70
$6.50	16.0	74.2%	9.5	$1.93
$7.00	17.8	79.2%	10.5	$2.15
$7.50	19.6	83.9%	11.5	$2.37
$8.00	21.3	90.4%	12.4	$2.57
$8.50	22.9	95.6%	13.2	$2.76

Calculated IRR at various price levels



	3.5	4.0	4.5	5.0	5.5	6.0	6.5	7.0	7.5	8.0	8.5
— Upstream & Pipeline	12.6	14.0	15.4	16.7	17.9	19.0	20.1	21.1	22.1	23.0	23.9
— Upstream Only	29.8	39.7	48.7	56.3	62.9	68.9	74.2	79.2	83.9	90.4	95.6

Internal Rate of return

	Step One: Model An Owned Project			
	CapCosts	Op Costs	Revenues	Cash Flows
Units:		1000	1000	
Dollars		0.1	5	
Product		100	5000	
Year				
0	(20,000)			(20,000)
1		(100)	5,000	4,900
2		(100)	5,000	4,900
3		(100)	5,000	4,900
4		(100)	5,000	4,900
5		(100)	5,000	4,900
6		(100)	5,000	4,900
7		(100)	5,000	4,900
8		(100)	5,000	4,900
9		(100)	5,000	4,900
10		(100)	5,000	4,900
			IRR:	21%

Internal Rate of Return

	Step Two: Model Capital Component of Tariff			
	Using PAYMENT function			
Units:				
Dollars	Balance	Interest	Payment	Balance
Product		10%		
Year				
0				20,000.00
1	20,000.00	2,000.00	(3,254.91)	18,745.09
2	18,745.09	1,874.51	(3,254.91)	17,364.69
3	17,364.69	1,736.47	(3,254.91)	15,846.25
4	15,846.25	1,584.63	(3,254.91)	14,175.97
5	14,175.97	1,417.60	(3,254.91)	12,338.66
6	12,338.66	1,233.87	(3,254.91)	10,317.62
7	10,317.62	1,031.76	(3,254.91)	8,094.47
8	8,094.47	809.45	(3,254.91)	5,649.01
9	5,649.01	564.90	(3,254.91)	2,959.01
10	2,959.01	295.90	(3,254.91)	0.00

Internal Rate of Return

	Step Three: Model Third Party Line with no FT but with tariff		
	Tariff	Revenues	Cash Flows
Units:			
Dollars			
Product			
Year			
0			
1	(3,354.9)	5,000.0	1,645.1
2	(3,354.9)	5,000.0	1,645.1
3	(3,354.9)	5,000.0	1,645.1
4	(3,354.9)	5,000.0	1,645.1
5	(3,354.9)	5,000.0	1,645.1
6	(3,354.9)	5,000.0	1,645.1
7	(3,354.9)	5,000.0	1,645.1
8	(3,354.9)	5,000.0	1,645.1
9	(3,354.9)	5,000.0	1,645.1
10	(3,354.9)	5,000.0	1,645.1
		IRR:	#NUM!

Internal Rate of Return

	Step Four: Model Third Party Line		
	with some additional capital		
	Tariff	Revenues	Cash Flows
Year			
0			(100.0)
1	(3,354.9)	5,000.0	1,645.1
2	(3,354.9)	5,000.0	1,645.1
3	(3,354.9)	5,000.0	1,645.1
4	(3,354.9)	5,000.0	1,645.1
5	(3,354.9)	5,000.0	1,645.1
6	(3,354.9)	5,000.0	1,645.1
7	(3,354.9)	5,000.0	1,645.1
8	(3,354.9)	5,000.0	1,645.1
9	(3,354.9)	5,000.0	1,645.1
10	(3,354.9)	5,000.0	1,645.1
			1645%

Internal Rate of Return

	Step Five: Model Third Party Line with some more additional capital		
	Tariff	Revenues	Cash Flows
Year			
0			(2,000.0)
1	(3,354.9)	5,000.0	1,645.1
2	(3,354.9)	5,000.0	1,645.1
3	(3,354.9)	5,000.0	1,645.1
4	(3,354.9)	5,000.0	1,645.1
5	(3,354.9)	5,000.0	1,645.1
6	(3,354.9)	5,000.0	1,645.1
7	(3,354.9)	5,000.0	1,645.1
8	(3,354.9)	5,000.0	1,645.1
9	(3,354.9)	5,000.0	1,645.1
10	(3,354.9)	5,000.0	1,645.1
			82%

Internal Rate of Return

	Step Six: Model Third Party Line with yet more additional capital		
	Tariff	Revenues	Cash Flows
Year			
0			(6,750.0)
1	(3,354.9)	5,000.0	1,645.1
2	(3,354.9)	5,000.0	1,645.1
3	(3,354.9)	5,000.0	1,645.1
4	(3,354.9)	5,000.0	1,645.1
5	(3,354.9)	5,000.0	1,645.1
6	(3,354.9)	5,000.0	1,645.1
7	(3,354.9)	5,000.0	1,645.1
8	(3,354.9)	5,000.0	1,645.1
9	(3,354.9)	5,000.0	1,645.1
10	(3,354.9)	5,000.0	1,645.1
	IRR:		21%

FASB 47 Disclosure of Long Term Obligations (1981)

- This statement requires that an enterprise disclose its commitments under unconditional obligations that are associate with suppliers financing arrangements. Such obligations often are in the form of take-or-pay contracts and throughput contracts.

FASB 47 Disclosure of Long Term Obligations (1981)

- Example 2
- 27. C Company has entered into a throughput agreement with a natural gas pipeline providing that C will provide specified quantities of natural gas (representing a portion of capacity) for transportation through the pipeline each period while the debt used to finance the pipeline remains outstanding. The tariff approved by the Federal Energy Regulatory Commission contains two provision, a demand charge and a commodity charge. The demand charge is computed to cover debt service, depreciation, and certain expected expenses.

FASB 47 Disclosure of Long Term Obligations (1981)

- 27. (cont.) The commodity charge is intended to cover other expenses and provide a return on the pipeline company's investment. C Company must pay the demand charge based on the contract quantity regardless of actual quantities shipped, while the commodity charge is applied to actual quantities shipped. Accordingly, the demand charge multiplied by the contracted quantity represents a fixed and determinable amount.

FASB 47 Disclosure of Long Term Obligations (1981)

- 28. C' disclosure might be as follows:
  - C company has signed an agreement providing for the availability of needed transportation capacity through 1990. Under that agreement, the company must make specified minimum payments monthly. The aggregate amounts of such required payments at December 31, 19X1 is as follows (in thousands):

FASB 47 Disclosure of Long Term Obligations (1981)

- 28 (cont).

• 19X2	$	5,000
• 19X3		5,000
• 19X4		5,000
• 19X5		4,000
• 19X6		4,000
• Later years		26,000
• Total		49,000
• Less: Amount representing interest		(9,000)
• Total at present value	$	40,000

FASB 47 Disclosure of Long Term Obligations (1981)

- 28 (cont).
- In addition the company is required to pay additional amount depending on actual quantities shipped under the agreement. The companies total payments under the agreement were (in thousands) $6,000 in 19W9 and $5,000 both in 19X0 and in 19X1.

Contractual Commitments

The following table summarizes the Group's principal contractual obligations at December 31, 2003. Further information on borrowings and capital leases is given in Item 18 — Financial Statements — Note 29 on page F-47 and further information on operating leases is given in Item 18 — Financial Statements — Note 17 on page F-29.

	Payments due by period						
Expected payments by period under contractual obligations and commercial commitments	Total	2004	2005	2006	2007	2008	2009 and thereafter
				($ million)			
Borrowings (a)	20,143	9,366	2,674	2,786	1,299	945	3,073
Finance lease obligations	4,634	127	243	248	240	248	3,528
Operating leases	8,115	1,275	1,066	895	799	728	3,352
Decommissioning liabilities	7,504	86	156	173	154	156	6,779
Environmental liabilities	2,430	465	441	402	276	186	660
Pensions (b)	26,682	633	649	652	659	666	23,423
Other post-employment benefits (c)	11,768	242	252	259	263	264	10,488
Unconditional purchase obligations (d)	67,828	45,491	7,076	3,133	1,888	1,655	8,585

(a) Expected payments exclude interest payments on borrowings.

(b) Represents the expected future contributions to funded pension plans and payments by unfunded pension plans.

(c) Represents the expected future payments for postretirement benefits.

(d) Represents any agreement to purchase goods or services that is enforceable and legally binding and that specifies all significant terms. The amounts shown include arrangements to secure long-term access to supplies of crude oil, natural gas, feedstocks and pipeline systems. In addition, the amounts shown for 2004 include purchase commitments existing at December 31, 2003 entered into principally to meet the Group's short term manufacturing and marketing requirements. The price risk associated with these crude oil, natural gas and power contracts is discussed in Item 11 — Quantitative and Qualitative Disclosures about Market Risk on page 170.

The following table summarizes the nature of the Group's unconditional purchase obligations.

	Payments due by period						
Unconditional purchase obligations payments due by period	Total	2004	2005	2006	2007	2008	2009 and thereafter
				($ million)			
Crude oil and oil products	22,043	19,350	844	452	422	374	601
Natural gas	19,439	13,189	2,575	1,141	489	398	1,647
Chemicals and other refinery feedstocks	10,049	2,277	1,666	753	563	545	4,245
Utilities	11,612	9,622	1,231	289	62	54	354
Transportation	2,814	738	510	365	247	204	750
Use of facilities and services	1,871	315	250	133	105	80	988
Total	67,828	45,491	7,076	3,133	1,888	1,655	8,585

BPs 2003 20(f)

- Unconditional purchase obligations (d)
- (d) Represents any agreement to purchase goods or services that is enforceable and legally binding and that specifies all significant terms. The amounts shown include arrangements to secure long-term access to supplies of crude oil, natural gas feedstocks and pipeline systems.
- Obligations set out for five years, after five years and in total

Why does this matter?

- Moody' Investors Service
- Authors (or "Contacts"):
- Barbara Havlicek, Kevin Stoklosa, Greg Jonas, Laura Levenstein, Pamela Stumpp, Michel Madelain, Trevor Pijper, Wofgang Draak, Waylon Iserhoff, Brian Cahill, Thomas Keller, Takohiro Morita
- The Analysis of Off-Balance Sheet Exposures, A Global Perspective
- July 2004

Moody's Rating Methodology

- Take-Or-Pay Contracts
- Take or pay contracts are another form of purchase commitment typically found in the … energy industry. … Such contracts can be problematic if market conditions and raw material prices change or if the price of the end product drops. Regardless of whether of not the contract becomes problematic, Moody's factors payments under take-or-pay contracts into the analysis of future cash flows and may also adjust the balance sheet if necessary. (Havlicek page 7)

Why does this matter?

- Standard & Poor's
- Authors (and "Analytical Contacts"):
- Solomon B. Samson, Scott Sprinzen, Emmanuel Dubois-Pelerin, Kenneth C. Pfeil
- Corporate Ratings Criteria
- 2006

Standard and Poor's Rating Methodology

- Off balance-sheet financing
  - Analysis of liabilities is not limited to those shown on the company's balance sheet. Off balance-sheet items factored into the leverage analysis include the following:
    - Operating leases
    - Guarantees, debt of joint ventures and unconsolidated subsidiaries
    - Take-or-pay contracts and obligations under throughput and deficiency agreements…
  - (Samson pgs. 28-29)

Standard and Poor's Rating Methodology

- Various methodologies are used to determine the proper adjustment value for each off-balance-sheet item. In some cases, the adjustment is straightforward. For example, the amount of guaranteed debt can simply be added to the guarantor's liabilities. Other adjustments are more complex or less precise. (Samson pg. 29)

Closing Thought:

- E.C. Capen and D.F.Casey The Economics of Creative Financing

  Society of Petroleum Engineers 11664 (1983)

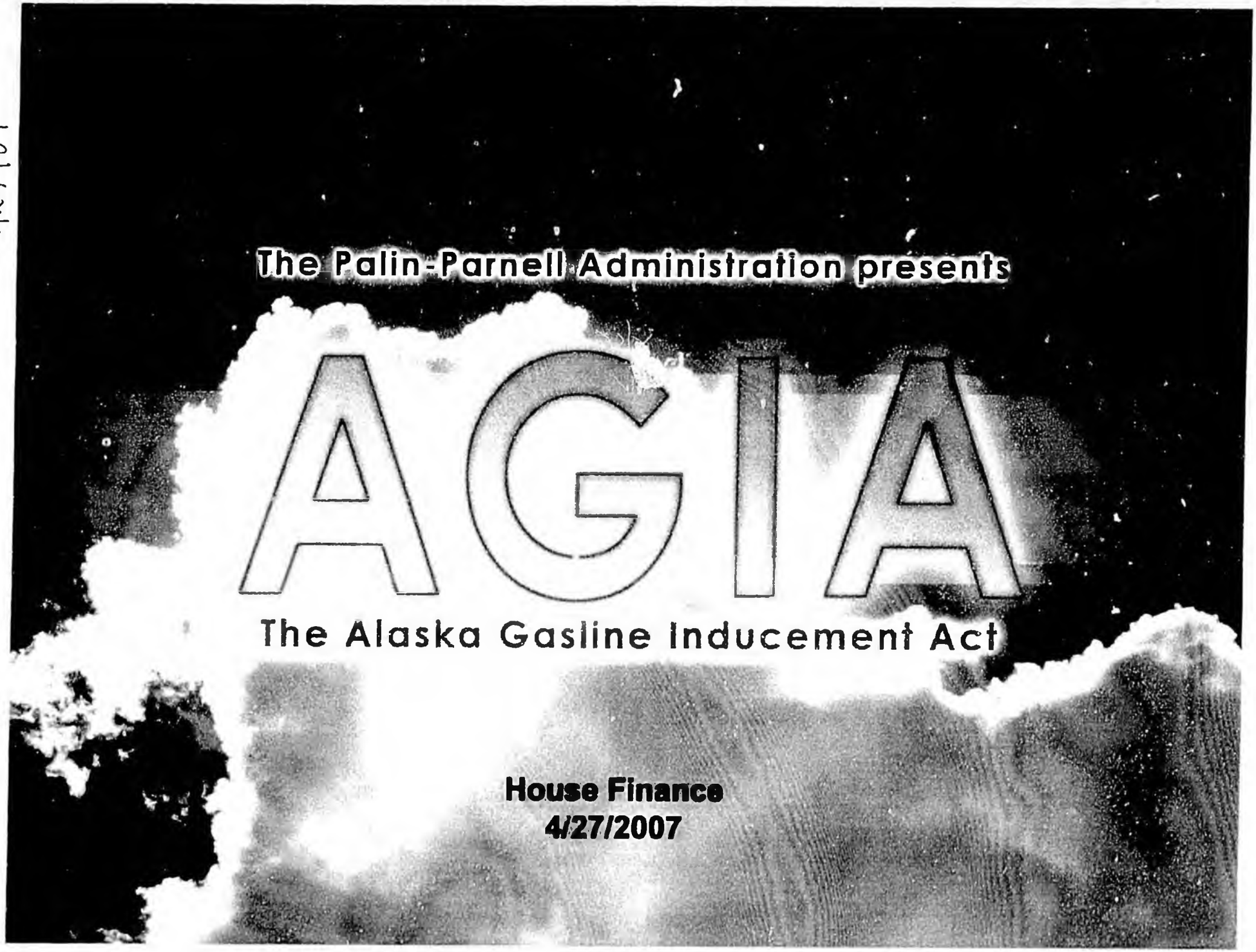
Closing Thought:

- Now and then, someone comes in and announces that he has discovered the business man's equivalent to the Fountain of Youth – a corporate money tree. The person will instruct us that his pet project (PP) need not compete for cash in the budgeting process because he has found a benefactor, Mr. S. Claus, willing to put up the money at no cost save some "small monthly payments" to be worked out later. These payments should come from PP's profits and represent no real drain on the company.

Close of Closing Thought

- To be sure we seldom see requests as blatant as portrayed above, but we nevertheless sense some misunderstandings about how to evaluate projects that have alternatives to outright purchase of goods and equipment. Has the old maxim prohibiting free lunches somehow been set aside with regard to so called creative financing? No, more likely the lunch costs more than normal, but we're not always sure who pays. (Capen & Casey pg. 241)

4/27/07


The Palin-Parnell Administration presents
AGIA
The Alaska Gasline Inducement Act
House Finance
4/27/2007

AGIA Overview

AGIA
The Alaska Gasline Inducement Act

AGIA:

- Is a **commercial vehicle** that creates a competitive playing field
- Provides a **pipeline on Alaska's terms**
- Is a **transparent process**, with **transparent inducements**.

Commercial Vehicle AGIA

The Alaska Gasline Inducement Act

- AGIA uses competitive bidding, not negotiation.
- Successful bidding process requires AGIA's inducements
  - Without inducements, no third-party bidders
  - Without third-party bidders, state has no ability to get a pipeline on its desired terms

Commercial Vehicle AGIA

The Alaska Gasline Inducement Act

AGIA's inducements:

- Midstream inducement of $500 million:
  - *reduces licensee's project development risks, especially an independent pipeline licensee*
- Upstream tax and royalty inducements:
  - *coupled to the licensed midstream project to make license more valuable*, by
    - Encouraging open season participation
    - Ensuring that state will stick with its licensed partner
- Requirement to obtain pipeline certificate reduces overall project risks, improves state's strategic position

A Project on the State's Terms

AGIA
The Alaska Gasline Inducement Act

- By creating a more competitive playing field, state can specify some "must haves"
- State's "must haves" focus on its future:
  - A pipeline sooner
  - A competitive and vibrant oil and gas industry
  - Jobs and careers, not only from the pipeline itself, but also from a competitive oil patch
  - Gas for Alaskans

A Project on the State's Terms

AGIA
The Alaska Gasline Inducement Act

- State's "must haves" all obtained through pipeline tariff and access terms that ensure a competitive oil and gas industry
  - Competitive oil and gas industry can flower if pipeline ownership gives no upstream competitive advantage
  - Jobs and careers for Alaskans will be maximized by ensuring a competitive upstream industry
  - Cheap gas for Alaskans will be enjoyed if pipeline regularly expands

A Project on the State's terms

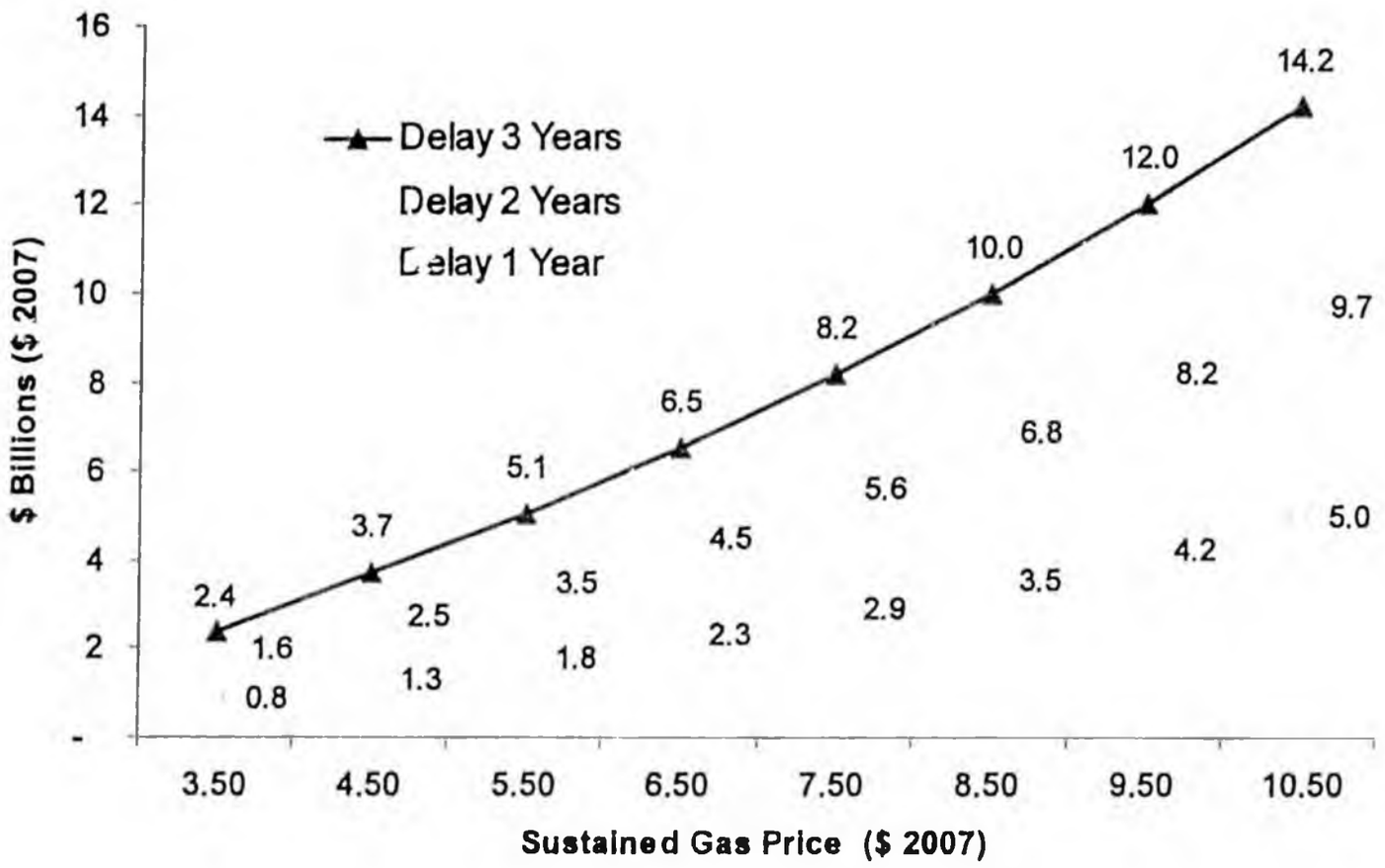
AGIA
The Alaska Gasline Inducement Act

- A pipeline sooner
- Required minimum 70/30 debt/equity ratio ensures reasonable base tariffs
- Expansion requirements ensure that gas found by any party can access the pipeline
- Rolled-in rate requirements ensure that all parties have an economic incentive to explore for gas, competition for oil and gas, and all of Alaska's gas can get into the pipeline

Gets a Pipeline Sooner

AGIA
The Alaska Gasline Inducement Act

Losses to State for Each Year Delay
Discounted at 5% per Year



Tariff and State Revenue Effects of Debt-Equity Structure

AGIA
The Alaska Gasline Inducement Act

Debt%	Equity%	Tariff	Present Value State Revenue $ Billions
80%	20%	$1.47	37.4
75%	25%	$1.56	36.9
70%	30%	$1.65	36.3
65%	35%	$1.74	35.7
60%	40%	$1.84	35.1
55%	45%	$1.95	34.5
50%	50%	$2.06	33.8
45%	55%	$2.18	33.1

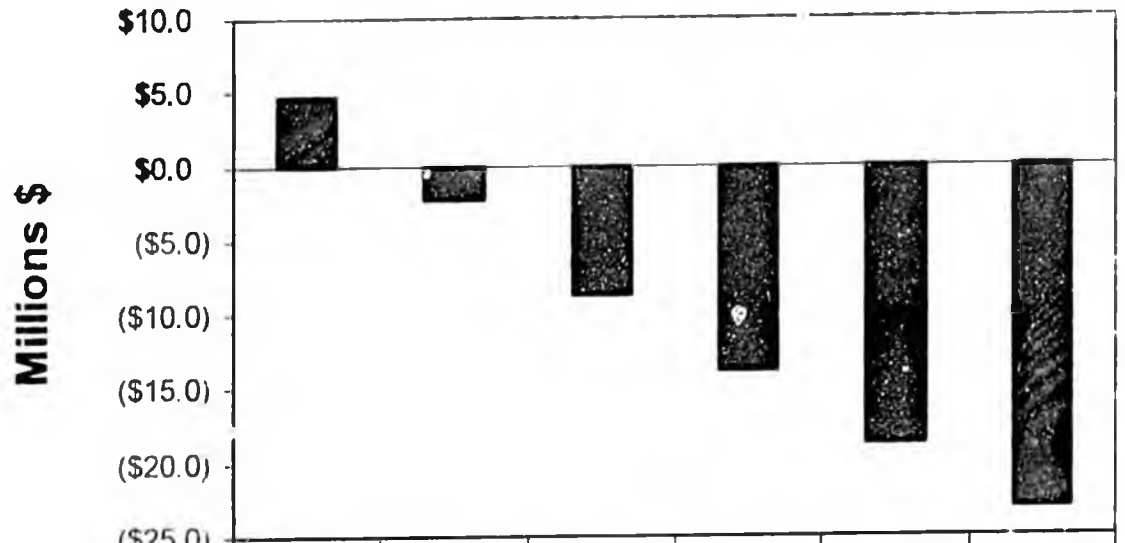
AGIA protects the states interest in low tariffs. It ensures that no less than 70/30 will be used rather than 50/50, with associated tariff benefits of 41 cents and state revenue benefits of $2.5 billion.

Expansion Provisions
Cost-of-Delay To Explorer

AGIA
The Alaska Gasline Inducement Act

Expected Net Present Value (NPV 12)

Generic North Slope Prospect

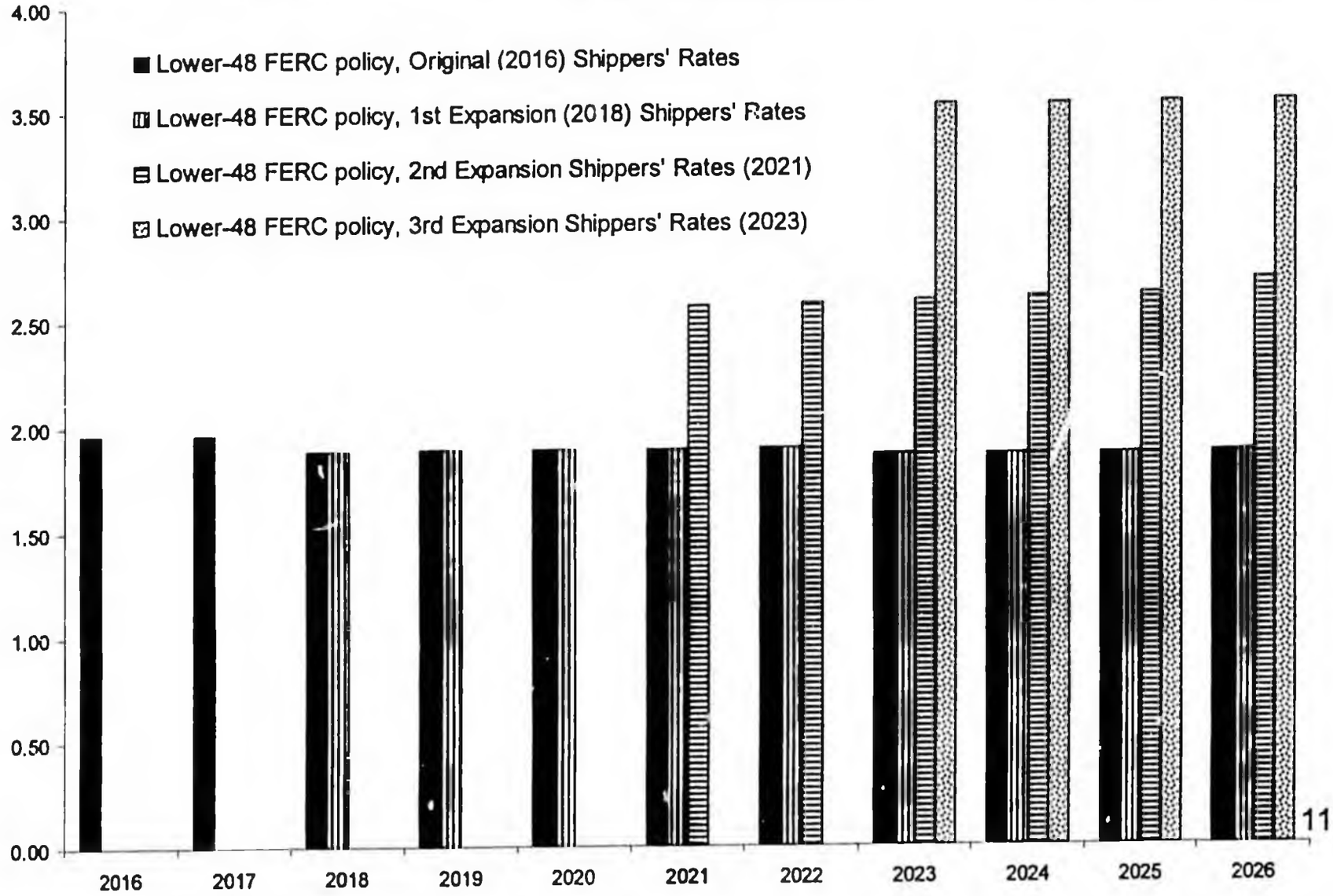


	0	1	2	3	4	5
Operator's NPV	$4.7	($2.3)	($8.7)	($13.8)	($18.7)	($23.1)

Years Delay to First-Production

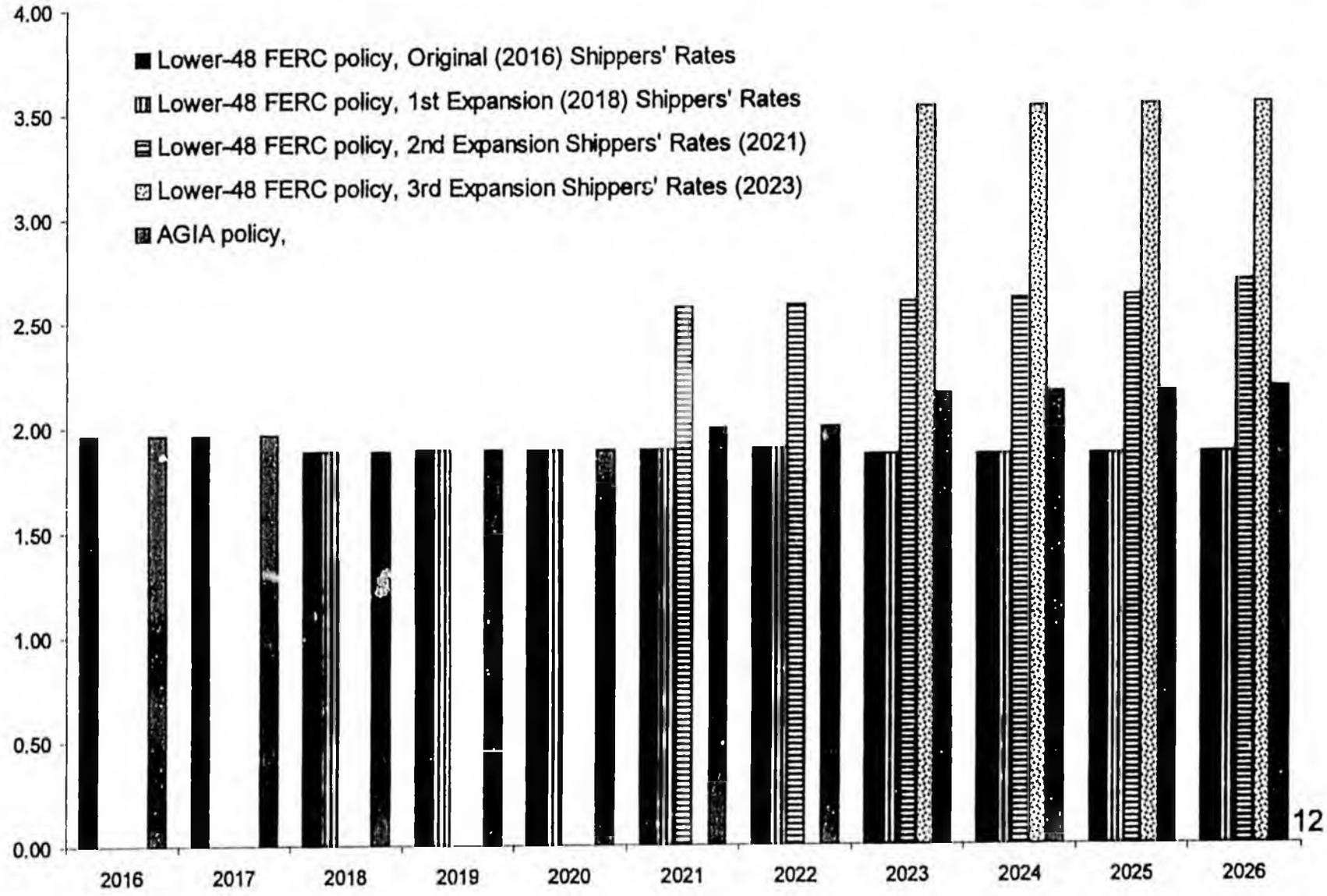
FERC Lower 48 Expansion rate policy

AGIA
The Alaska Gasline Inducement Act



AGIA
Expansion rate policy

AGIA
The Alaska Gasline Inducement Act



Rolled-in Rates Encourage Exploration

AGIA
The Alaska Gasline Inducement Act

Examples:

Scenario 1: Add 1 Bcf/day with compression (from 4.5 to 5.5 Bcf/day)

Rolled-in	*Incremental*
$6.0 million	**$6.5 million**

Scenario 2: Add 1 Bcf/day with compression (from 5.5 to 6.5 Bcf/day)

Rolled-in	*Incremental*
$4.3 million	-$5.4 million

Scenario 3: Add 700 MMcf/day with looping (from 6.8 to 7.5 Bcf/day)

Rolled-in	*Incremental*
$ .9 million	-$25.5 million

Transparent Public policy

AGIA
The Alaska Gasline Inducement Act

- AGIA creates a competitive process, not a negotiated process
- Bids will be submitted, commented upon by the public, and evaluated
- A winner will be chosen by the Commissioners
- The Commissioners' decision will be reviewed by the Legislature

Transparent Public policy

AGIA
The Alaska Gasline Inducement Act

- The value of AGIA's inducements are up front and transparent
- Contrast: AGIA's $500 million versus SGDA contract $10 billion+
  - Much of SGDA contract value was hidden and unquantifiable
  - AGIA's benefits are explicit and quantifiable

Summary

AGIA
The Alaska Gasline Inducement Act

- Without competition, and the forward movement that AGIA provides, Alaskans will have to wait, and watch, until the Producers do the pipeline on their timeline and on their terms.
- AGIA changes the playing field.
- AGIA is a **commercial vehicle** that creates a competitive playing field, provides a **pipeline on Alaska's terms**, in a **transparent manner**.