

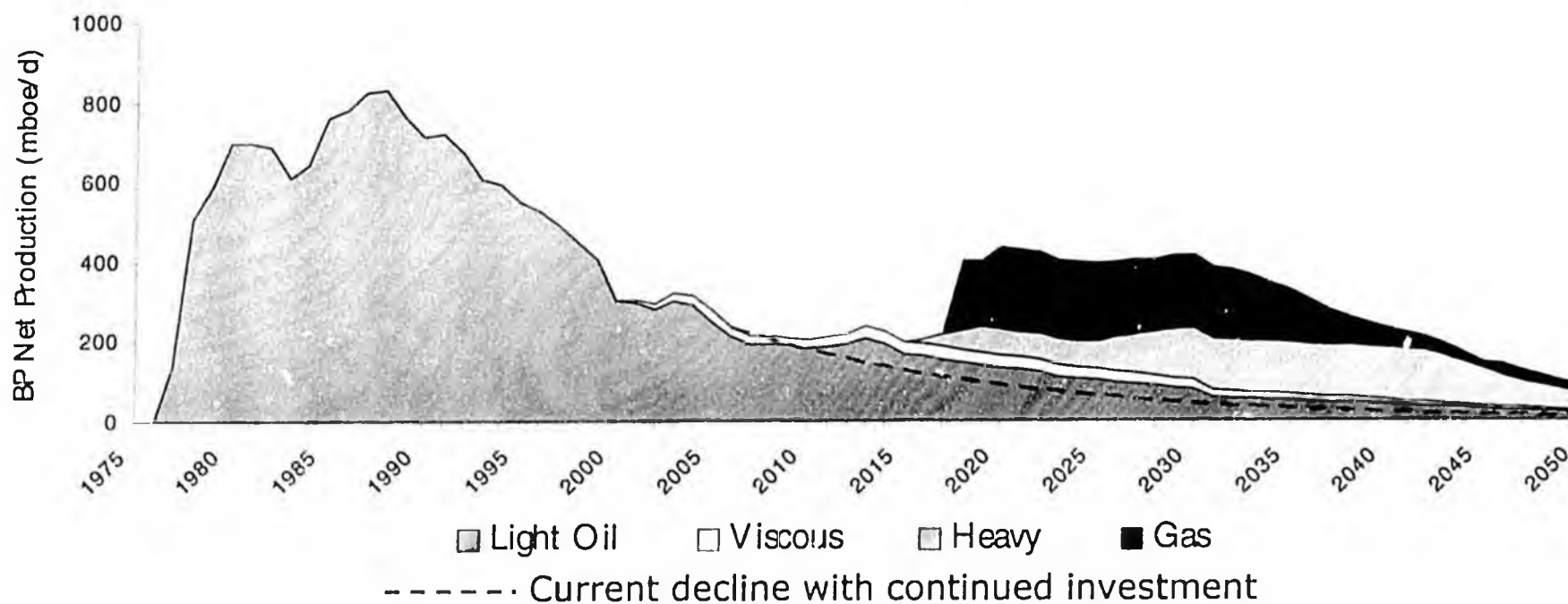
AK LEGISLATURE FINANCE COMMITTEES FILES 2007-2008 3212

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BP's Vision for Alaska

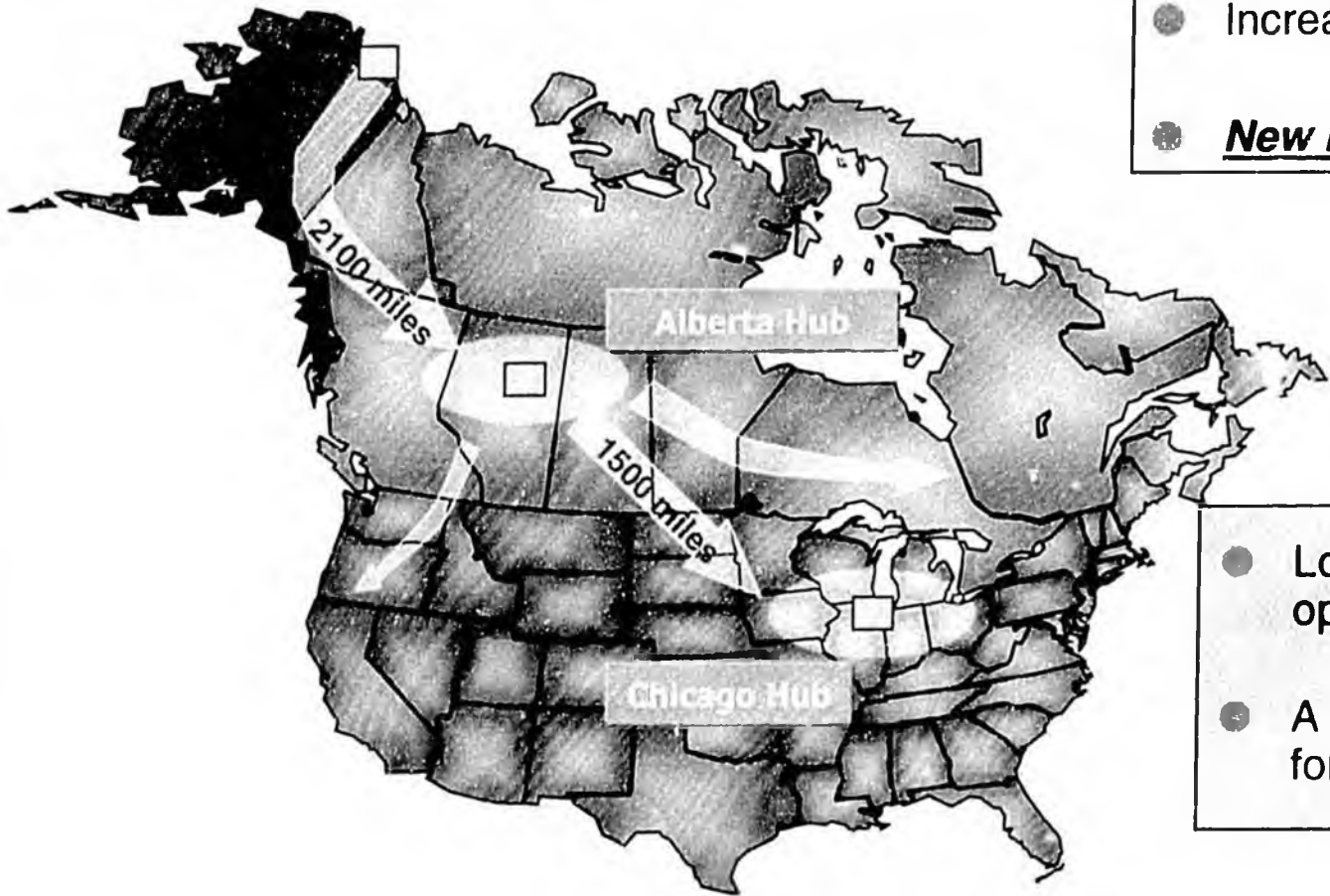
- BP has a long history in Alaska....
-and we look forward to a 50-year future
- That future is only possible with a gas pipeline
- BP wants to bid under AGIA and hopes it will be modified appropriately



What A Successful Gasline Means

- **Jobs** for Alaskans
- Additional **revenue** for future generations

- Increased **economic activity**
- **New businesses** created



- Long term **gas supply** opportunity for Alaskans
- A more diversified economy for **decades**

HB

177

(FILE 2)


HFIN

FILE

5/2/07

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

Dan E. Dickinson
CPA, CMA

- 
- 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 ngl/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)

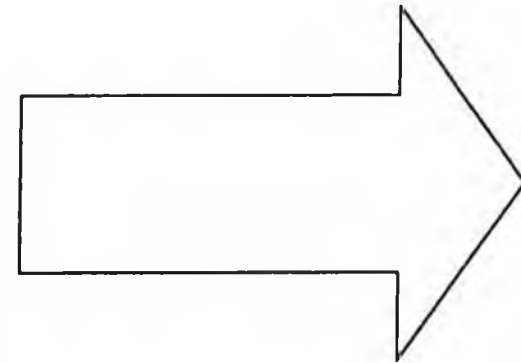
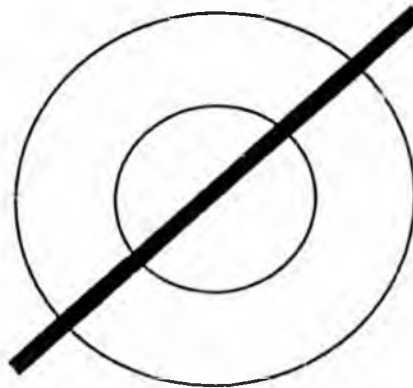
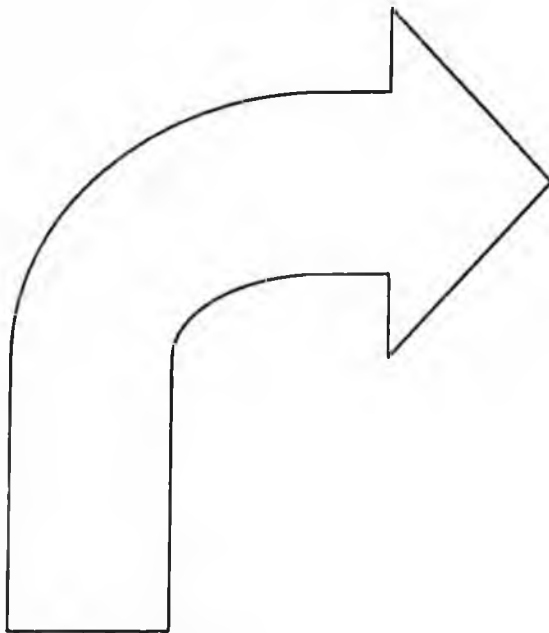
PPT Point of Production for Gas

Is the 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?	no	Is the gas subjected to or recovered by mechanical separation or run through a gas processing plant?	yes	Is the gas subjected to or recovered by mechanical separation but not run through a gas processing plant?	no	Is the gas run through a gas processing plant?
yes		no		yes		yes
Point of Production = the first point where gas processing is completed or where the gas treatment begins, whichever is further upstream		Point of Production = the first point where gas is accurately metered		Point of Production = the first point where gas is accurately metered after completion of mechanical separation		Point of Production = the first point where gas is accurately metered downstream of the plant

Gas Point of Production

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

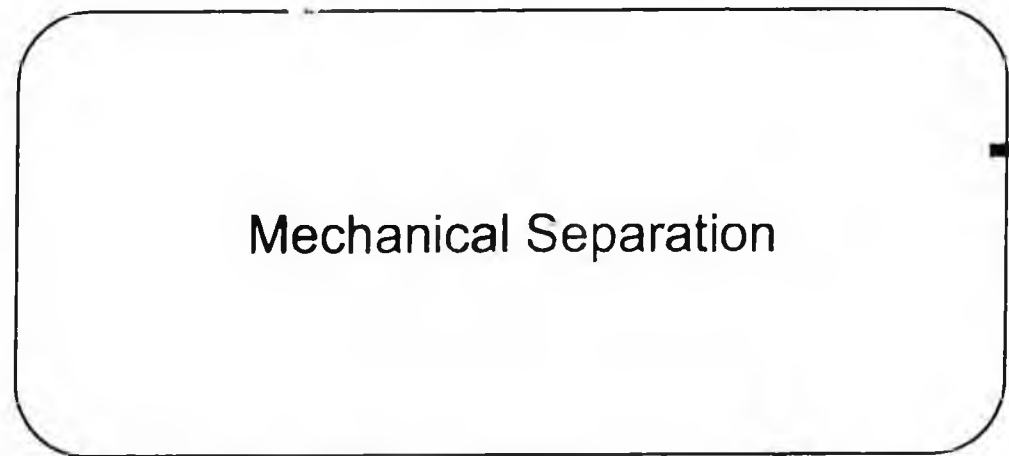
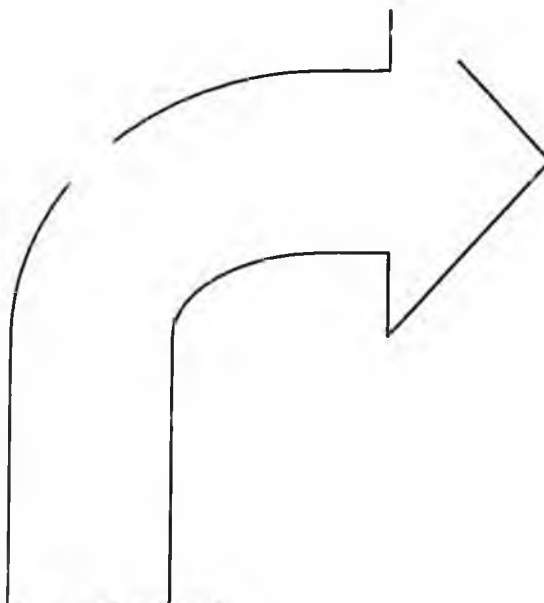
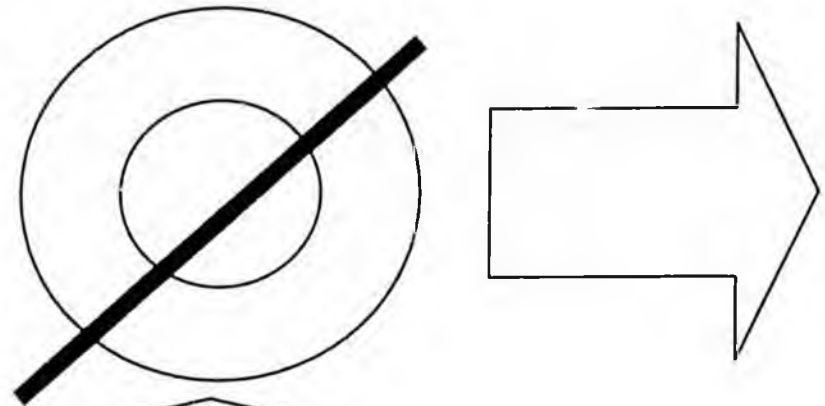
Point of Production: first point accurately metered



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



May 2 2007

Dan E. Dickinson CPA

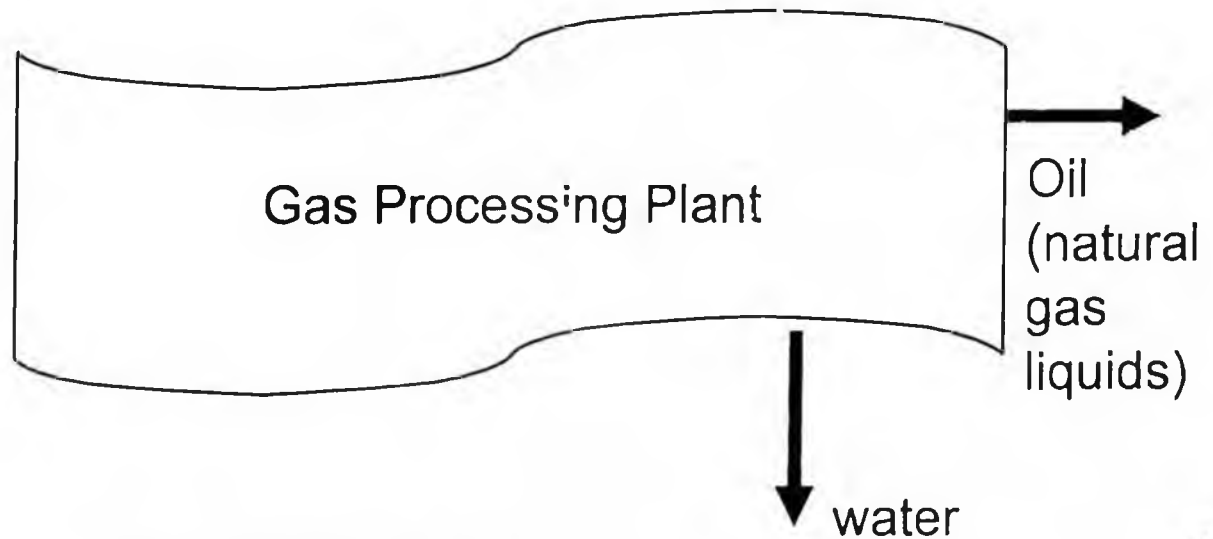
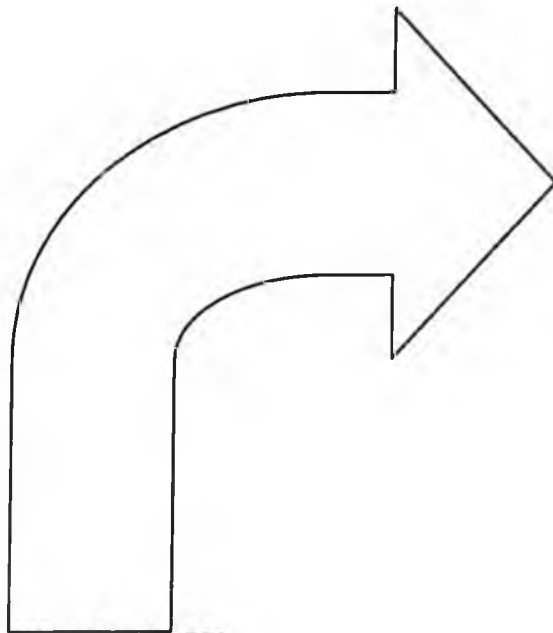
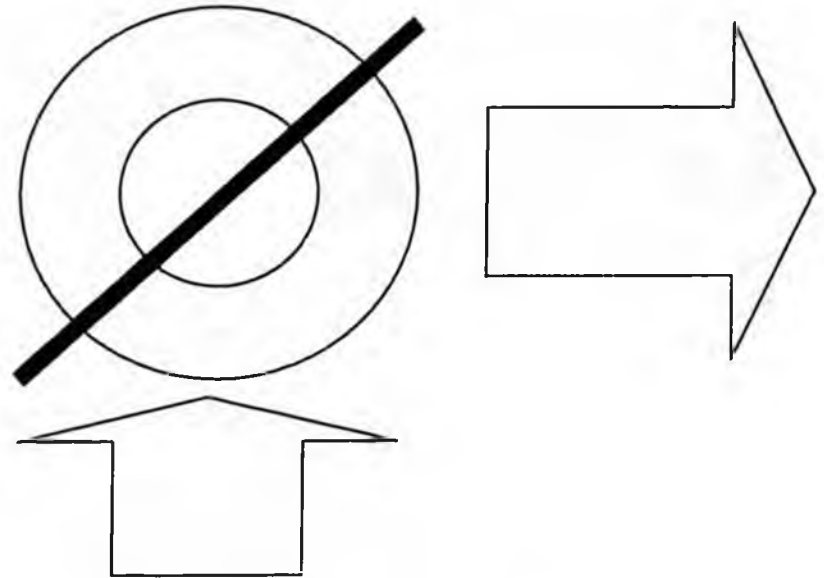
water

oil

Gas Point of Production

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

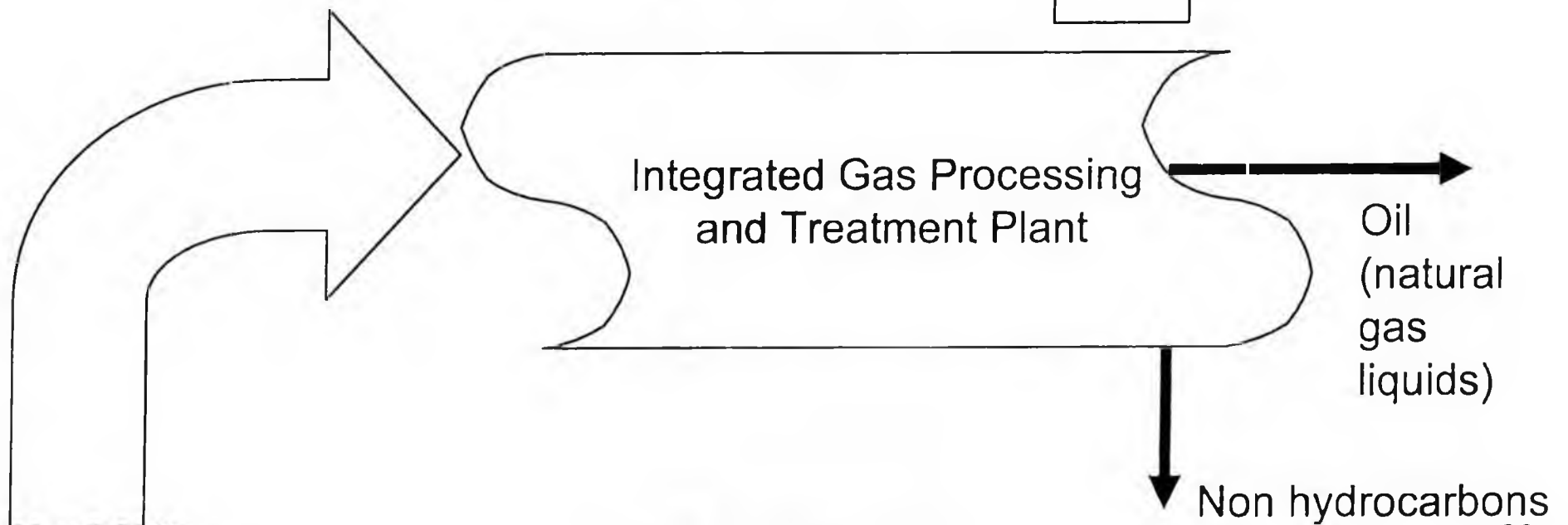
Point of Production after gas processing: first point accurately metered downstream of plant



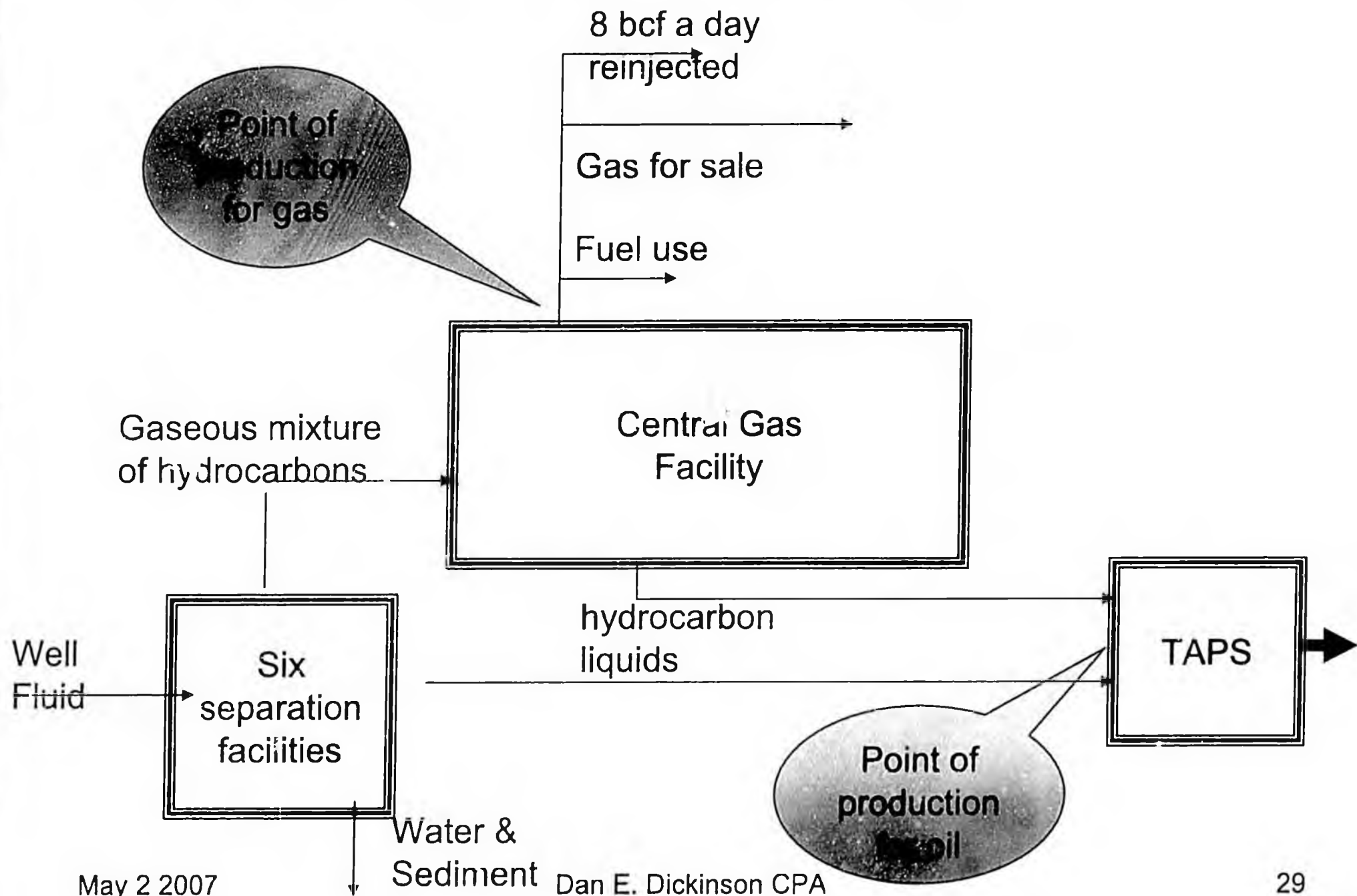
Gas Point of Production

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.

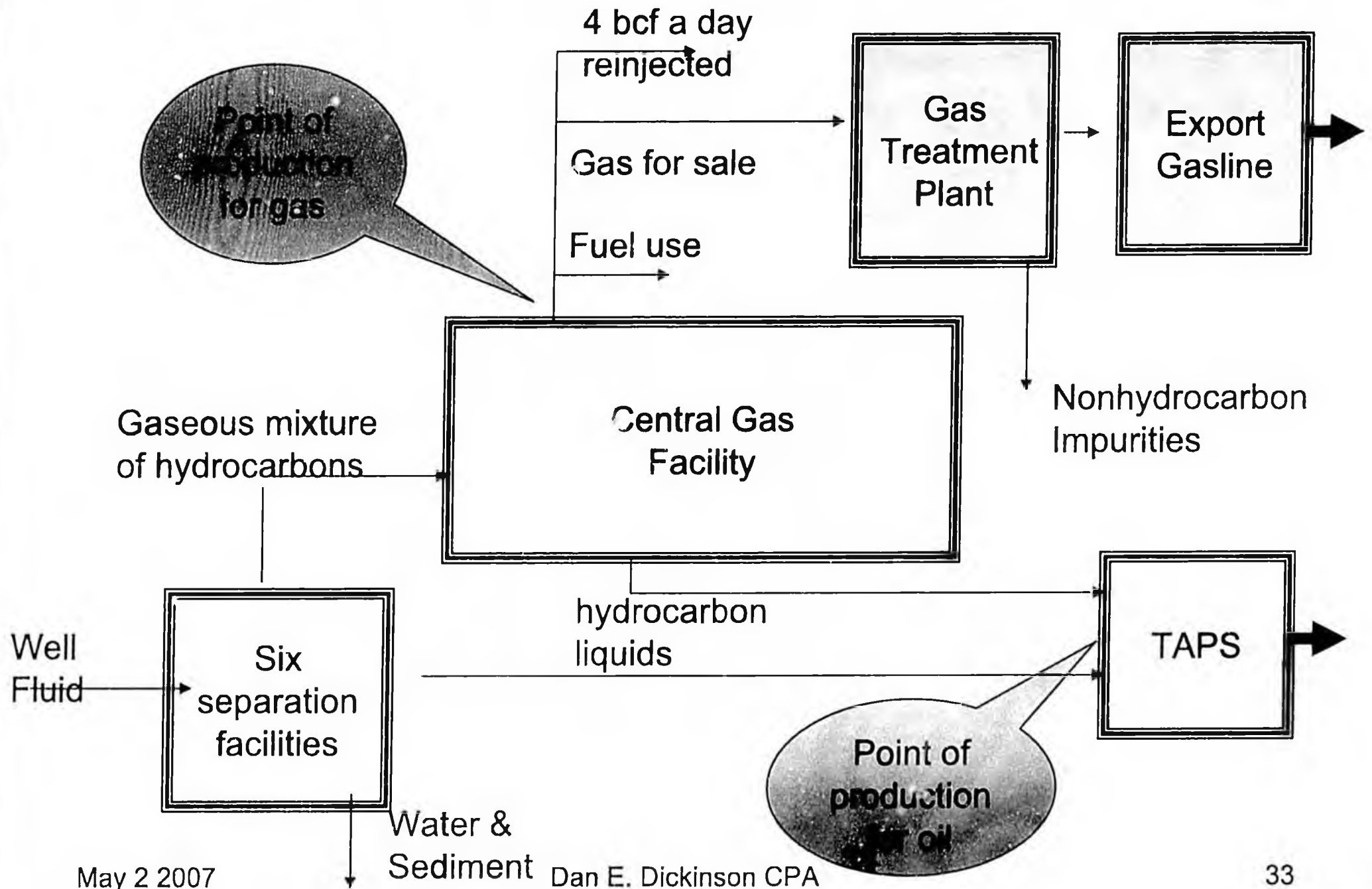
North Slope Central Gas Facility

- 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).

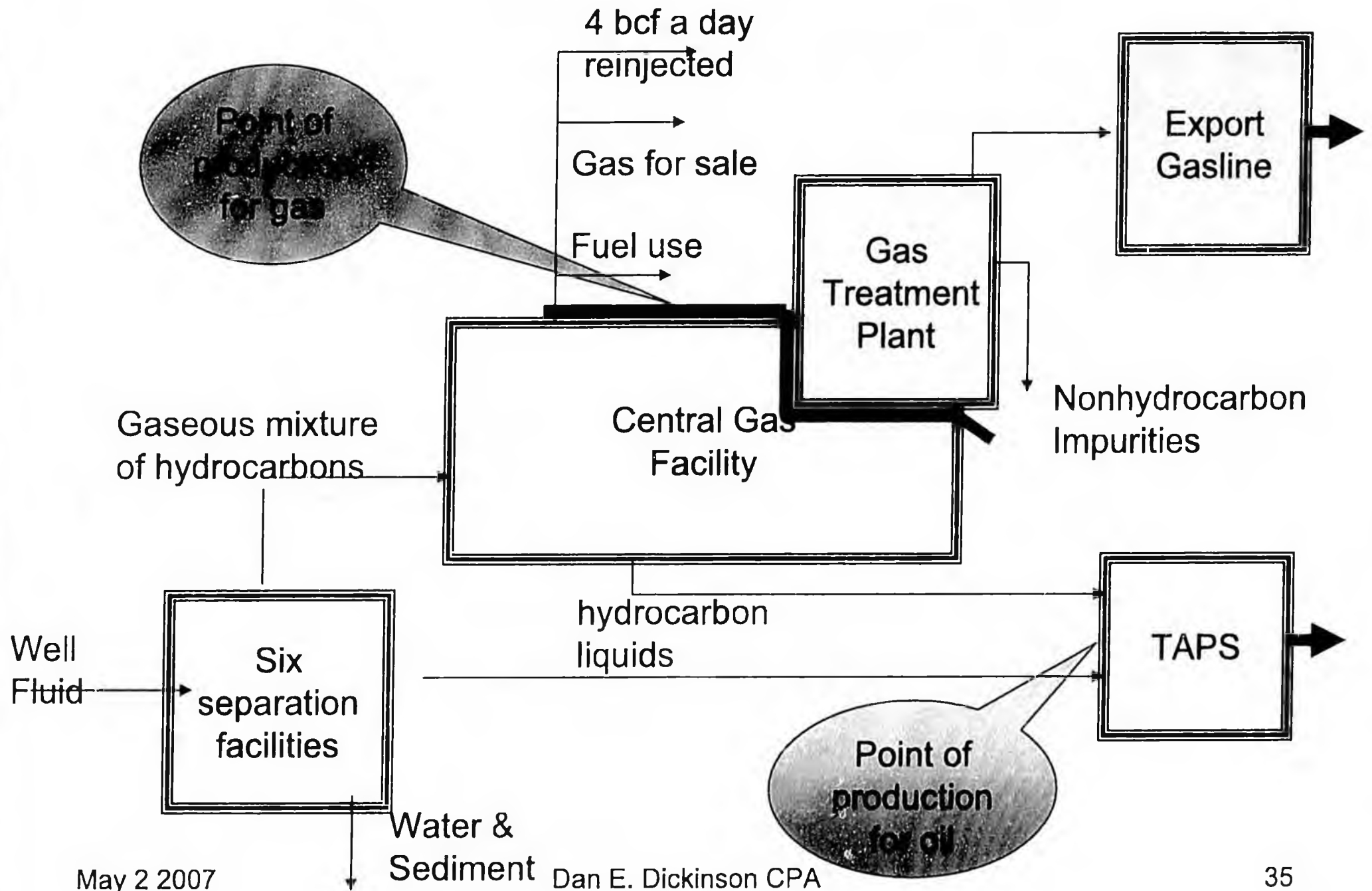
Prudhoe Bay: Point of Production under the PPT with a GTP




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



	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

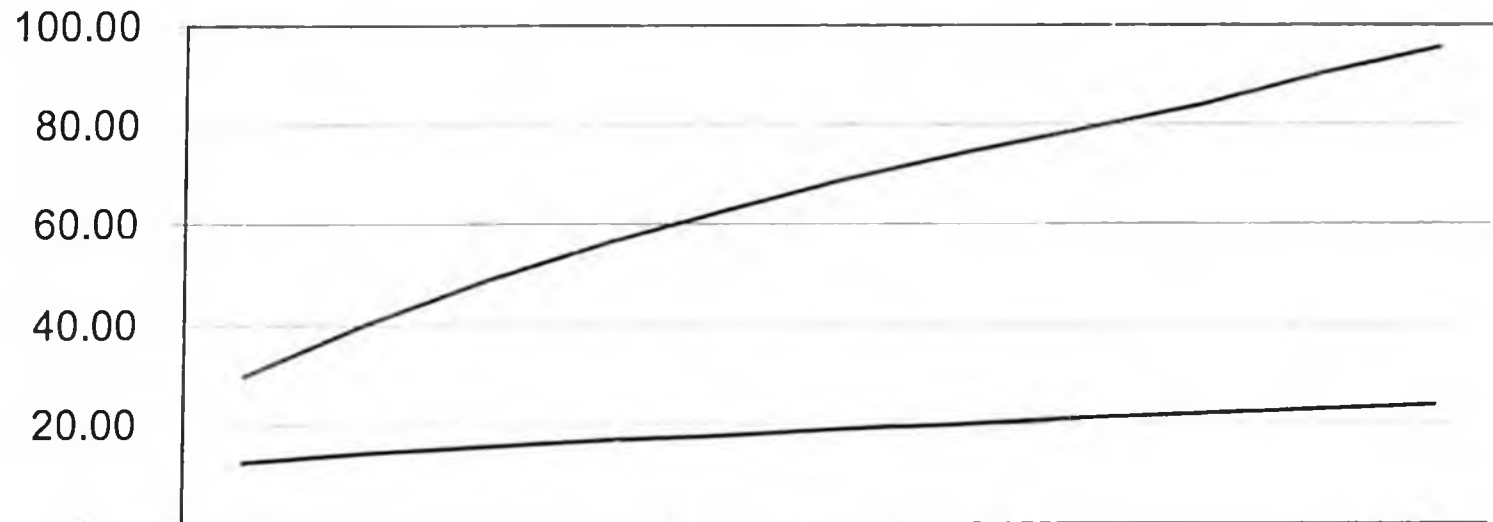
Producer Upstream Returns

Base case cost = \$20.5B



	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	1,345.1
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)

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						2009 and thereafter
	Total	2004	2005	2006	2007	2008	
	(\$ million)						
Borrowings (a)	20,143	9,366	2,674	2,786	1,299	945	3,073
Finance lease obligations	4,634	127	243	248	210	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						2009 and thereafter
	Total	2004	2005	2006	2007	2008	
	(\$ 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, Wolfgang 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 or 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						2009 and thereafter
	Total	2004	2005	2006	2007	2008	
	(\$ million)						
Borrowings (a)	20,143	9,366	2,674	2,786	1,299	945	3,073
Finance lease obligations	4,634	127	243	248	210	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						2009 and thereafter
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	(\$ million)						
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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

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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	Payments Due by Period				2002 Total Amount
		2004	2005-2008	2009 and Beyond	2003 Total Amount	
		<i>(millions of dollars)</i>				
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.