SCOMM

142:18

HOUSE COMMITTEE REPC T

(7)

Date Referred to Committee: March 17, 2005

FURTHER REFERRALS: Oil and Gas Resources

Date of Committee Action: Feb 3, 2006

The HOUSE SPECIAL COMMITTEE ON WAYS AND MEANS considered: HB 223

HOUSE BILL NO. 223 NATURAL GAS PIPELINE INCENTIVE/ GAS TAX

"An Act levying a tax on certain known resources of natural gas, conditionally repealing the levy of that tax, and authorizing a credit for payments of that tax against amounts due under the oil and gas properties production (severance) tax if requirements relating to the sale and delivery of the natural gas are met; and providing for an effective date."

Recommends it be replaced with [ ] HCS *or* **[ ] CS for** _____(_____)

For Senate Bills with new title: [ ] Technical Title [ ] New Title: HCR_____ [ ] Same Title [ ] New Title

[ ] attach amendments
[ ] add new referral to _____Committee
[ ] Letter of Intent_____Committee

List of Abbrev for Depts.:
ADM
CED
COR
CRT
EED
DEC
DFG
GOV
HSS
LEG
LAW
LWF
MVA
DNR
DPS
REV
DOT
UA

NEW **FISCAL NOTES** *Assigned by Chief Clerk's Office				
List by Dept(s):	*FN#	Fiscal	Indet.	Zero
Rev				

PREVIOUS **FISCAL NOTES**				
List by Dept(s):	FN#	Fiscal	Indet.	Zero

Signing with recommendations	Printed Last Name	DP	DNP	NR	AM
Peggy Wilson	WILSON			↘	
	SAMUELS			X	
Paul Seaton	SEATON			X	
Max Gruenberg	Gruenberg	✓			
Chair: Bill Thomas	Weyhrauch				X
Chair:					

REPRESENTATIVE ERIC CROFT

Memorandum

TO: House Ways and Means Committee,
Representative Bruce Weyhrauch, Chair

FROM: Representative Eric Croft

DATE: April 26, 2005

RE: HB 223—Re-injection and duty to develop

In yesterday's hearing, Representative Samuels asked two important questions concerning the Gasline Now Act that warrant further explanation.

1. Is gas used for re-injection to enhance oil recovery exempt from the fee?

No. Gas used for re-injection can still be sold at a later date, and there are non-marketable gasses that can be used for maintaining well pressure. The Gasline Now Act bases the determination of the amount of gas subject to the fee on the methodology set out by Exxon in 1997 in a letter to the Alaska Oil and Gas Conservation Commission in which Exxon describes how it determines the amount of "hydrocarbon gas available for major gas sales." In this methodology, non-hydrocarbon gas, mostly carbon dioxide, is not included in the amount of "hydrocarbon gas available for major gas sales." This non-hydrocarbon gas can be successfully used for re-injection to enhance oil recovery and to maintain well pressure and will not be subject to the fee. If a producer chooses instead to use a portion of the "hydrocarbon gas available for major gas sales" for re-injection, then that gas will still be subject to the fee.

2. Is the lessees' duty to *find* or to *develop* resources under lease?

According to oil and gas attorney Spencer Hosie who is under contract with the state, a lease can be terminated not only for a failure to find resources, as Michael Hurley of Conoco Philips stated, but also for failure to develop the resources. To overcome the failure to develop issue, the state can either bring a lawsuit or implement a more direct incentive to get the lessees to develop our gas. Because lawsuits take years to reach a verdict, they are an ineffective means to keep the producers from delaying the gasline. The Gasline Now Act gives the producers an imminent reason to stop delaying its construction, and it helps the state pay for the infrastructure and other necessary services in the build-up to gasline construction.

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Representative_Eric_Croft@legis.state.ak.us

FISCAL NOTE

STATE OF ALASKA
2006 LEGISLATIVE SESSION

Fiscal Note Number:
Bill Version: HB 223
() Publish Date:

Revision Date/Time (Note if correction):
Dept. Affected: Revenue

Title: An Act Relating to the Taxation of Natural Gas Reserves
RDU: Taxation and Treasury
Component: Tax Division

Sponsor: Cro*, Crawford
Requester: House Committee on Ways and Means
Component No.: 2476

Expenditures/Revenues (Thousands of Dollars)

Note: Amounts do not include inflation unless otherwise noted below.

OPERATING EXPENDITURES	FY 2007	FY 2008	FY 2009	FY 2010	FY 2011	FY 2012
Personal Services						
Travel						
Contractual						
Supplies						
Equipment						
Land & Structures						
Grants & Claims						
Miscellaneous						
TOTAL OPERATING	*	*	*	*	*	*
CAPITAL EXPENDITURES						
CHANGE IN REVENUES ( )	1,010,280	1,010,280	1,010,280	1,010,280	1,010,280	1,010,280

FUND SOURCE (Thousands of Dollars)

1002 Federal Receipts						
1003 GF Match						
1004 GF						
1005 GF/Program Receipts						
1037 GF/Mental Health						
Other (Specify Type--Do not abbreviate)						
TOTAL	*	*	*	*	*	*

Estimate of any current year (FY2006) cost: 0.0
Check this box (X) if funding for this bill is included in the Governor's FY 2007 budget proposal:

POSITIONS

Full-time						
Part-time						
Temporary						

ANALYSIS: *(Attach a separate page if necessary)*

*See note on page 2.

This bill seeks to create a new tax to be levied on Alaska's known gas resources as defined in, and subject to the exemptions of, the bill. Estimates of gas resources have yet to be determined, however, according to the Department of Natural Resources, Division of Oil and Gas 2004 Annual Report, about 33,676 billion cubic feet of natural gas could be subject to the tax under the proposal. The tax would be repealed when the gas on which the tax is levied is transported to market.

Assuming 33,676 billion cubic feet are subject to the tax, a $.03 tax on each 1,000 cubic feet of natural gas would yield revenues of approximately $1,010 million per year until the gas is transported to market under conditions specified in the bill. When a gas export project is complete and the gas is marketed,

Prepared by: Robynn Wilson, Michael Williams, and Cherie Nienhuis
Phone: 269-1019
Division: Tax Division
Date/Time: 1/4/06 4:00 PM

Approved by: Tom Boutin, Deputy Commissioner
Date: 1/6/2006
Agency: Department of Revenue

ANALYS'S CONTINUATION

lessees will be allowed to claim a credit for certain of the taxes paid under this legislation with the following limitations: (1) In any year, the credit is limited to half of the lessee's production taxes on gas exported from the slope; (2) Taxes paid pursuant to this legislation before the lessee made an irrevocable commitment to either ship or sell the gas do not qualify for the credit; and (3) Any credit not used by 2030 expires.

*Administration costs are difficult to estimate. On its face, it could be a very simple tax to administer, requiring about 1/4 of a tax technician a year and some time from the State Petroleum Property Assessor. The bill specifies that DOR will determine the volume of taxable gas after consultation with the Department of Natural Resources and the Alaska Oil and Gas Conservation Commission. Having three agencies involved in the determination of gas reserve estimates may unduly complicate the already uncertain science of reserve estimation and could result in legal challenges. *The bill specifies that no taxes will be levied on reserves of less than one trillion cubic feet, and there are at least two fields where reserves are estimated to be just about one trillion cubic feet, which could trigger an expensive conflict about whether taxes of $30 million a year were owed for each field*. Combining this with other potential legal challenges, the defense of the assessment could run very high.

At a minimum, the DOR State Petroleum Property Assessor would need $100,000 per year for contract expertise and administrative review for the purpose of determining taxable gas volumes. A tax technician at $14,000 (.25 FTE) per year would also be required. Expenses in the first year of implementation are estimated to be $50,000 for DOR personnel and $85,000 for support from the Department of Law in the development and establishment of regulations.

The above costs do not cover expenses incurred as a result of legal challenges.

Once the gas is being marketed, there will be additional costs incurred by the department for the purpose of determining the amount of credit to be applied to production tax liabilities. It is highly unlikely that these costs will be incurred prior to FY2012; therefore, these costs do not appear on this fiscal note.

Alaska State Legislature

House of Representatives

Representative Harry Crawford -- District 21
Representative Eric Croft -- District 25

HB 223—The Gasline Now Act

The Gasline Now Act is a useful tool for encouraging construction of a North Slope gas pipeline by charging a fee to gas producers for not producing Alaska's gas and refusing to ship gas or build a gas pipeline.

Once it's built, the Gasline Now Act goes away.

The fee ends when gas first flows through a pipeline, either an All-Alaska line or the Canadian line, with at least 2.0 billion cubic feet per day (bcfd) from the North Slope to a commercial market.

Any producer can get all of their fees back if they commit to sell or ship gas.

A producer can get a credit for fees paid under the Gasline Now Act if the producer makes a commitment to sell or ship gas down the pipeline that actually gets built.

The credit will be applied against the production tax owed by the producer for gas shipped down the pipeline.

The earlier they commit, the more credit they earn.

The credit is equal to the amount of fees paid from the time the producer makes the commitment to sell or ship until the gasline is built.

The credit will be applied against no more than 50% of the producer's production tax until the year 2030 or until the total amount of credit is repaid, whichever comes first.

A producer can avoid the fees altogether.

Any producer unwilling to ship their gas down a pipeline can relinquish its taxable leases back to the state for re-lease to a producer willing to cooperate in the pipeline process.

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Phone: Representative Crawford 465-3438 Representative Croft 465-4998

The Gasline Now Act will encourage exploration.

The fee only applies to gas in units leased before 2002 that have more than 1 trillion cubic feet (tcf) of known gas resource (Prudhoe Bay and Point Thompson). The fee does not apply to new gas finds regardless of size. Currently, explorers have little incentive to search for gas because there is no way to get any gas to market. HB 223 gives an incentive to build a pipeline that will provide all North Slope producers a way to get gas to market and thereby encourage them to look for more.

The amount of taxable gas is determined with a formula set out by Exxon in 1997 to determine the quantity of marketable gas in a lease. It only includes gas that should be marketed but does not include natural gas liquids shipped down the TAPS pipeline, gas used to power production facilities or gas used for re-injection to enhance oil recovery.

The Gasline Now Act creates a stable fiscal structure for both industry and Alaska

By attaching the credit to a producer's production tax, producers can count on a reduced and stable tax rate until 2030. The credit will smooth any future changes in the severance tax by lessening the blow to producers of future tax increases.

The Gasline Now Act will stabilize Alaska's fiscal situation by bringing in $600-900 million in gasline revenue starting in 2007 to pay for increased demands on state services during pipeline construction. Money from the Gasline Now Act can be used for new schools, roads and public safety officers and can be invested to provide a cushion for the state in future economic down years.

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Alaska State Legislature

House of Representatives

Representative Harry Crawford -- District 21
Representative Eric Croft -- District 25

HB 223 Gasline Now Act

Details

Section 1. Creates the storage fee.

Sec. 43.58.210. Tax on known gas resources.

- $0.03 per mcf
- Estimated $960 million in annual revenue

Sec. 43.58.220. Property subject to tax.

- (a) – The fee applies to "known gas resources" excepting gas described below.
- (b) – The fee does not apply to:
  - gas hydrates
  - Coal bed methane or other non-conventional gas
  - CO_2 or other non-hydrocarbon gas
  - Undiscovered gas within a lease
  - Gas used for fuel to run the facilities on the lease
    - The five year limit prevents a lessee from deducting estimate amounts of gas to be used for fuel for the life of the lease
  - Gas liquids shipped down TAPS.
- (c) – The fee only applies to gas in leases that meet certain criteria.
  - Only gas that has been discovered but not marketed for ten years will be taxed.
  - Gas must be in a lease that was in a state approved unit before 2002 (the fee will not apply to new exploration).
  - Gas must be in a unit with at least 1 trillion cubic feet of gas.

Sec. 43.58.230. Determination of volume of taxable gas.

- (a) – Revenue will consult with DNR and AOGCC to determine the amount of taxable gas each year.
- (b) – If the lessees within a unit can agree on how to allocate the taxable gas, then the Dept. of Revenue will use those allocations.

E-mail: Representative_Harry_Crawford@legis.state.ak.us, Representative_Eric_Croft@legis.state.ak.us

- (c) – If the lessees cannot agree to allocations, then Revenue can allocate in one of the following ways:
  - Revenue and lessees come to an allocation agreement
  - Based on gas in place under each specific lease
  - Based on how much gas is left in the unit
  - Based on surface area each lessee hold within the unit
- (d) – Revenue can let DNR or AOGCC allocate the taxable gas

Sec. 43.58.240. Returns and payment of tax.

- (a) through (e) Describes the method of payment and other technicalities of submitting returns and making the fee payments to the state.

Sec. 43.58.250. Regulations.

- Directs the Department of Revenue to adopt regulations to address
  - Preparing lists of property to be taxed,
  - Noticing lessees the amount of gas to be taxed,
  - Procedures for appeal, putting the burden of proof on the appellant, and
  - Certification of the final tax roll and any supplemental tax rolls.

Sec. 43.58.295. Definitions.

- Creates definition of "known gas resources."
- Defines other terms for the purpose of this act.

Section 2. Creates the credit.

Sec. 43.55.027. Credit against tax as it applies to certain natural gas production.

- (a) –Allows a credit against the lessee's severance taxes due for the fees charged in the Gasline Now Act.
- (b) –Allows lessees to claim and take the credit.
- (c) –Fees paid under the Gasline Now Act can begin to be repaid after the pipeline is built as long as:
  - (1) the lessee has agreed to sell or ship gas
  - (2) the pipeline they agreed to sell to or ship on is the pipeline that is in operation, and
  - (3) the agreement that made the lessee eligible for the credit is actually the agreement it is shipping under.
- (d) –Defines the total amount of credit allowed and how much can be repaid at a time.
  - (1) The credit is applied against the lessee's monthly severance tax payment.
  - (2) Each month, the credit can be no more than 50% of the severance owed in that month.

- (3) The amount of credit allowed as the amount of money a lessee pays to the state after they make a qualifying agreement to ship or sell the gas until the pipeline is built.

- (e) –The credit ends at the end of the year 2030 whether or not all of the fees paid in have been refunded.
- (f) –Conforms the definition of lessee to the other sections of the bill.

Section 3. Termination of the Gasline Now Act.

- The Gasline Now Act fee sections are repealed upon completion of a 2bcf/day gas pipeline or combination of pipelines from the North Slope to either tidewater or the North American natural gas pipeline system.
- The credit provisions are not repealed.

Section 4. Surrender lease option.

- A lessee can avoid paying the fees under the Gasline Now Act for a particular lease if it gives that lease back to the state before the end of the calendar year 2006.

Section 5. Severability.

- This act is severable.

Section 6. Effective Date of the termination of the Gasline Now Act.

- See section 3.

Section 7. Effective date of lease surrender.

- A lessee can surrender its lease immediately upon passage of this act.

Section 8. Effective date of other sections.

- The Gasline Now Act takes effect January 1, 2007 so as to allow lessees time to prepare the shipping or sales agreements that would qualify them for the credit.

REPRESENTATIVE ERIC CROFT

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Representative Bruce Weyhrauch, Chair

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DATE: April 26, 2005

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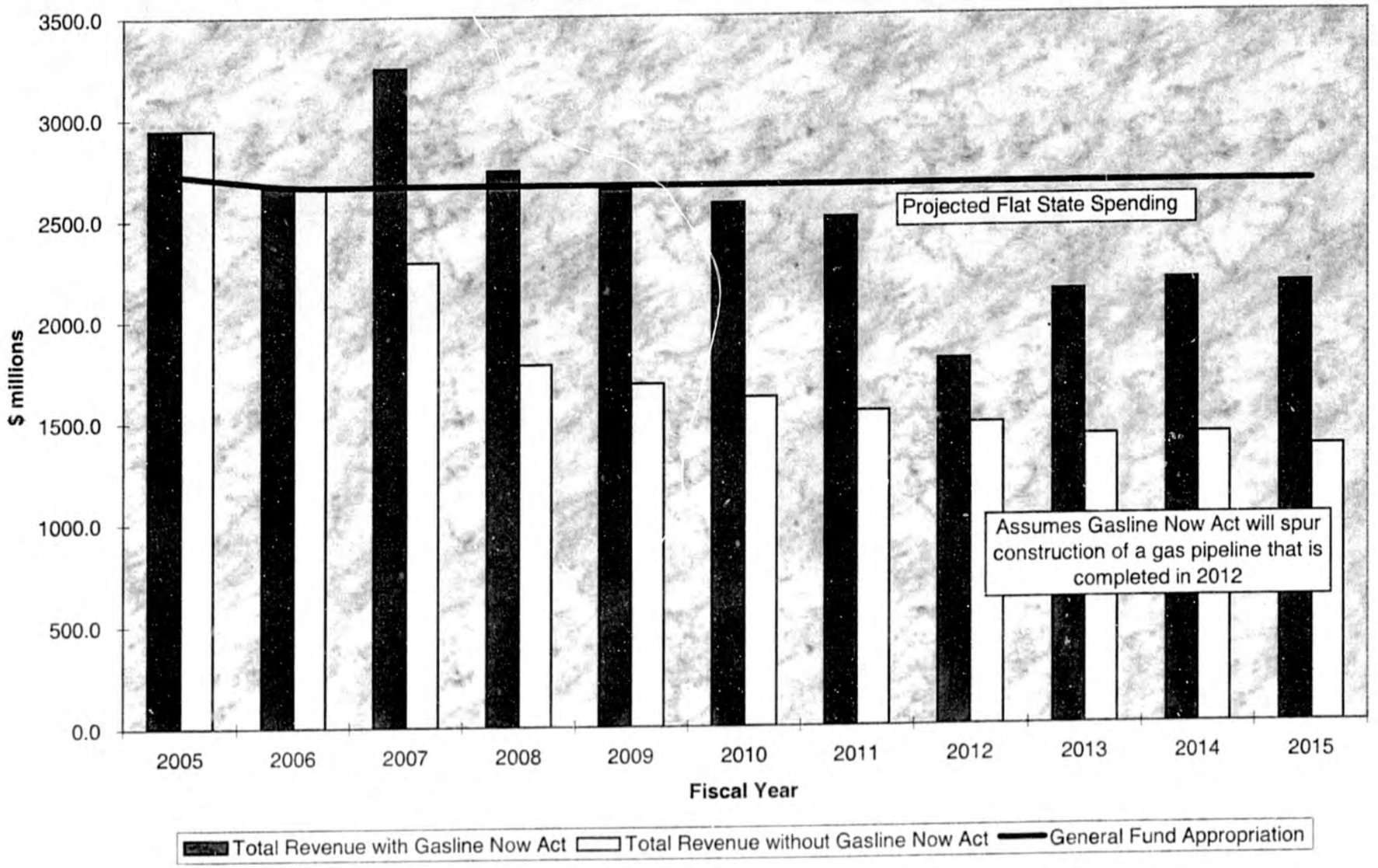
Gas Revenue Endowment Fund (GREF)
Pro-forma Operating Model (in millions unless noted)

Assumptions (production and tax estimates provided by DOR with full disclaimer)

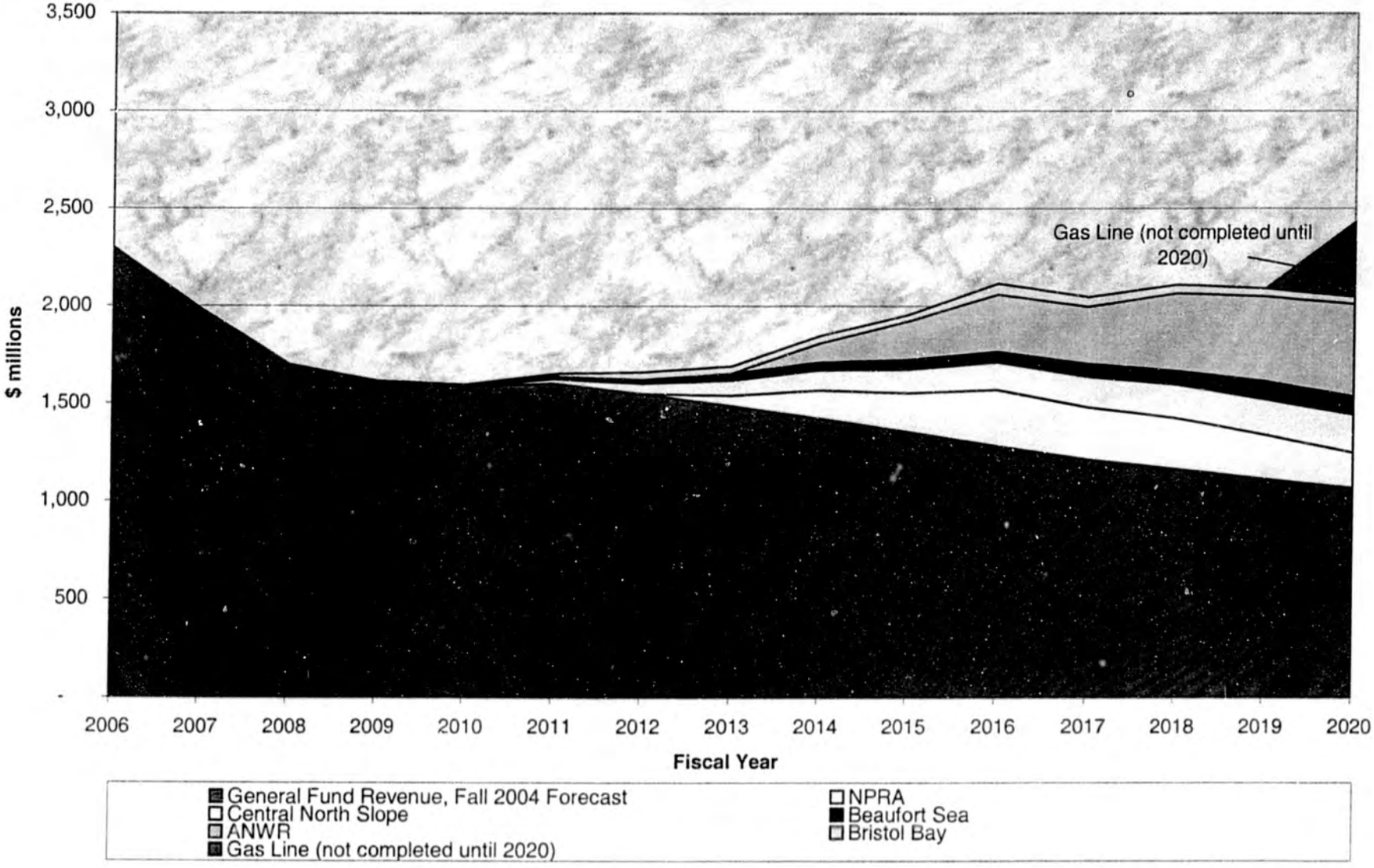
Chicago gas price ($/mmBtu)	varies	First production	2012
Sale volume (bcf)	4.5	Full production	2013
Lease volume (bcf)	4.712	POMV	5.0% 5 year average
Royalty	12.5%	GREF Earnings	8.0%
Severance	10.0%	ELF	80% - 90%

	Deposit to GREF			GREF Earnings			GREF POMV			GREF Balance		
Year	$4.00	$5.00	$6.00	$4.00	$5.00	$6.00	$4.00	$5.00	$6.00	$4.00	$5.00	$6.00
2007	0	0	0							0	0	0
2008	0	0	0	0	0	0				0	0	0
2009	0	0	0	0	0	0				0	0	0
2010	0	0	0	0	0	0				0	0	0
2011	0	0	0	0	0	0				0	0	0
2012	298	473	649	0	0	0				298	473	649
2013	618	984	1,349	24	38	52				940	1,495	2,050
2014	620	985	1,351	75	120	164	(15)	(24)	(32)	1,620	2,576	3,532
2015	621	987	1,354	130	206	283	(31)	(49)	(67)	2,340	3,720	5,102
2016	622	989	1,356	187	298	408	(48)	(76)	(104)	3,101	4,930	6,762
2017	624	992	1,360	248	394	541	(65)	(103)	(142)	3,908	6,214	8,521
2018	625	994	1,363	313	497	682	(83)	(132)	(181)	4,763	7,573	10,385
2019	627	996	1,366	381	606	831	(119)	(189)	(260)	5,652	8,985	12,322
2020	628	999	1,370	452	719	986	(157)	(250)	(343)	6,575	10,453	14,335
2021	630	1,002	1,374	526	836	1,147	(198)	(314)	(431)	7,533	11,977	16,425
2022	632	1,005	1,378	603	958	1,314	(240)	(382)	(523)	8,528	13,559	18,593
2023	634	1,008	1,382	682	1,085	1,487	(284)	(452)	(620)	9,560	15,199	20,843
2024	636	1,011	1,386	765	1,216	1,667	(331)	(525)	(721)	10,630	16,901	23,176
2025	638	1,014	1,390	850	1,352	1,854	(378)	(602)	(825)	11,740	18,665	25,595
2026	640	1,017	1,395	939	1,493	2,048	(428)	(681)	(934)	12,891	20,494	28,104
2027	642	1,021	1,399	1,031	1,640	2,248	(480)	(763)	(1,046)	14,084	22,392	30,704
2028	644	1,024	1,404	1,127	1,791	2,456	(533)	(848)	(1,163)	15,322	24,359	33,402
2029	646	1,028	1,409	1,226	1,949	2,672	(589)	(937)	(1,284)	16,604	26,399	36,199
2030	648	1,031	1,414	1,328	2,112	2,896	(647)	(1,028)	(1,410)	17,934	28,514	39,099
2031	651	1,035	1,419	1,435	2,281	3,128	(706)	(1,123)	(1,540)	19,313	30,707	42,106
2032	653	1,039	1,424	1,545	2,457	3,368	(768)	(1,222)	(1,675)	20,743	32,981	45,223
2033	656	1,042	1,429	1,659	2,638	3,618	(833)	(1,324)	(1,815)	22,226	35,338	48,455
Total deposits	13,633	21,676	29,721									
Final fund bal.	22,226	35,338	48,455									

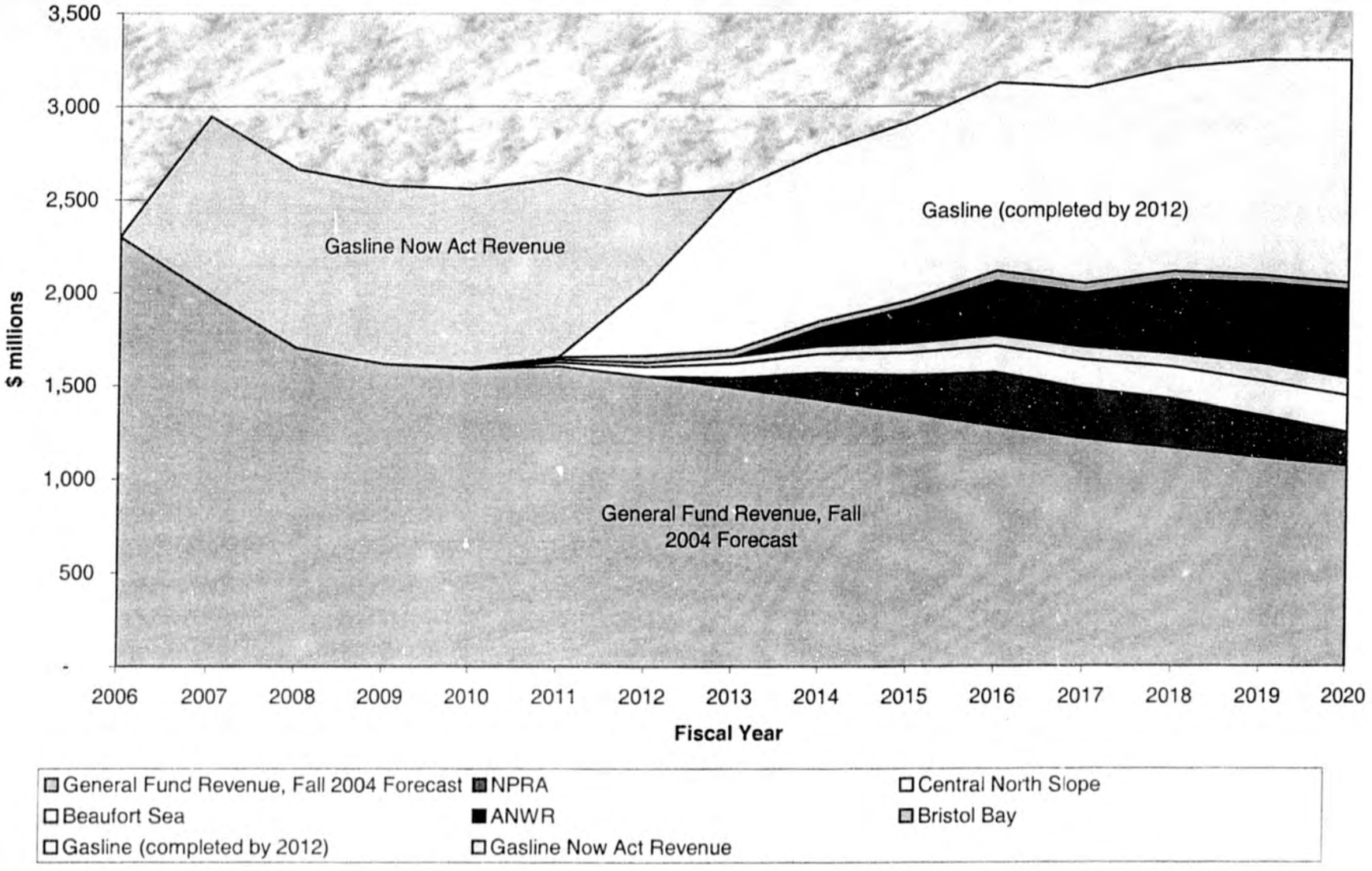
Gasline Now Act's Ability to Bridge the Gap



State's Revenue Picture without the Gasline Now Act



State's Revenue Picture with the Gasline Now Act



How the Gasline Now Act affects Alaska's ten year fiscal situation

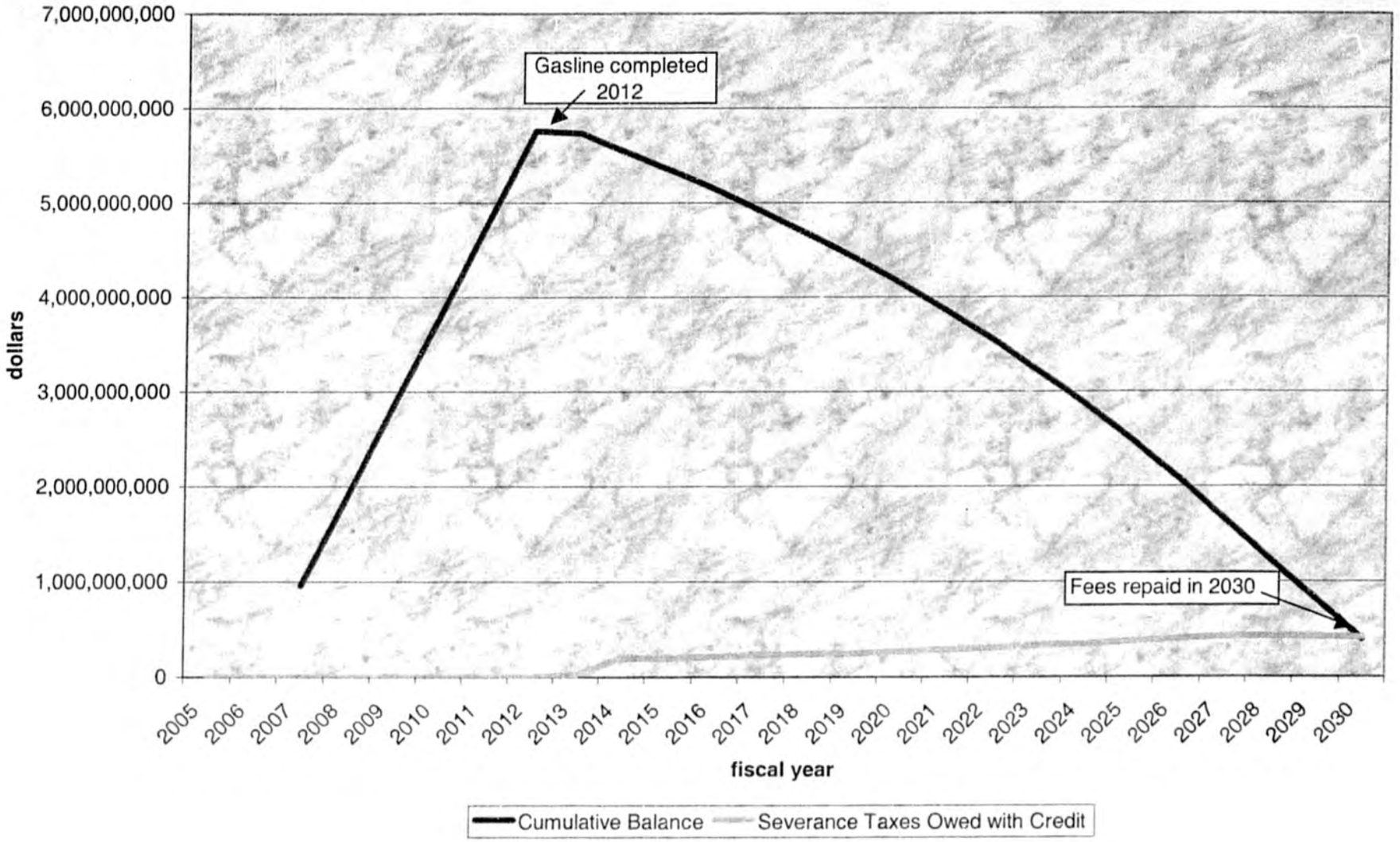
Fiscal Year	Gasline Now Act revenue	Total Projected Gasline Revenue	Gasline Revenue without Gasline Now Act	Gasline Now credit	Projected Gasline Revenue Less Credit	Other Unrestricted General Purpose Revenue	General Fund Approp.	Total Revenue without Gasline Now Act	Total Revenue with Gasline Now Act	Fiscal Gap without the Gasline Now Act	Fiscal Gap with the Gasline Now Act	Total Annual Benefit of Gasline Now Act
2005	0.0	0.0	0.0	0.0	0.0	2946.9	2720.5	2946.9	2946.9	226.4	226.4	0.0
2006	0.0	0.0	0.0	0.0	0.0	2664.0	2665.0	2664.0	2664.0	(1.0)	(1.0)	0.0
2007	960.0	0.0	0.0	0.0	0.0	2287.7	2665.0	2287.7	3247.7	(377.3)	582.7	960.0
2008	960.0	0.0	0.0	0.0	0.0	1779.5	2665.0	1779.5	2739.5	(885.5)	74.5	960.0
2009	960.0	0.0	0.0	0.0	0.0	1684.4	2665.0	1684.4	2644.4	(980.6)	(20.6)	960.0
2010	960.0	0.0	0.0	0.0	0.0	1615.8	2665.0	1615.8	2575.8	(1049.2)	(89.2)	960.0
2011	960.0	0.0	0.0	0.0	0.0	1543.3	2665.0	1543.3	2503.3	(1121.7)	(161.7)	960.0
2012	0.0	383.0	0.0	(66.0)	317.0	1480.3	2665.0	1480.3	1797.3	(1184.7)	(867.7)	317.0
2013	0.0	864.0	0.0	(148.0)	716.0	1415.7	2665.0	1415.7	2131.7	(1249.3)	(533.3)	716.0
2014	0.0	915.0	0.0	(152.0)	763.0	1418.9	2665.0	1418.9	2181.9	(1246.1)	(483.1)	763.0
2015	0.0	963.0	0.0	(157.0)	806.0	1354.9	2665.0	1354.9	2160.9	(1310.1)	(504.1)	806.0
												0.0
Total	4800.0	3125.0	0.0	(523.0)	2602.0	20191.4	29370.5	20191.4	27593.4	(9179.1)	(1777.1)	7402.0

in millions

Assumes construction of a gas pipeline to be competed in 2012 with passage of the Gasline Now Act

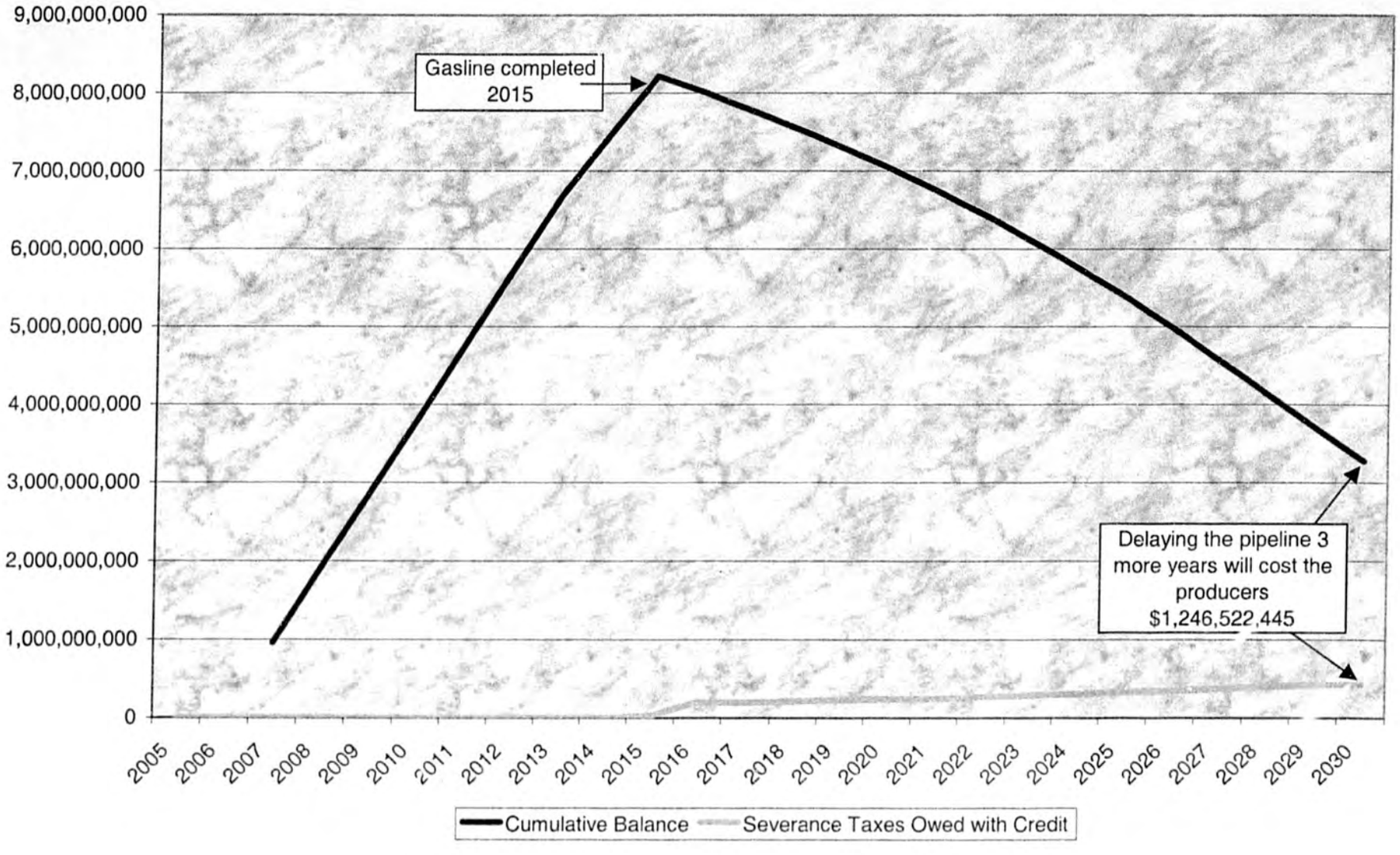
Assumes construction of a gas pipeline to be competed in 2020 without passage of the Gasline Now Act

Repayment Schedule of Gasline Now Act fees through the Severance Tax Credit
--fees paid on 32tcf and repaid at 50% of annual severance tax liability--



Repayment Schedule of Gasline Now Act fees through Severance Tax Credit

--fees paid on 32 tcf and repaid at 50% of annual severance tax liability assuming pipeline delayed until 2015--



Alaska Oil and Gas Association

AOGA

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Phone: (907)272-1481 Fax: (907)279-8114
Email: brady@aoga.org
Judith Brady, Executive Director

January 9, 2006

Representative Bruce Weyhrauch
State Capitol
Juneau, AK 99801-1182

RE: HB 223 & HB 63

Dear Representative Weyhrauch:

On behalf of the members of the Alaska Oil and Gas Association, I'm writing to express our grave concerns with House Bill 223, and House Bill 63, both scheduled for hearings this week in the House Special Committee on Ways & Means.

As you are aware, the Alaska Oil and Gas Association (AOGA) consists of seventeen member companies, representing the majority of oil and gas exploration, production, transportation, refining and marketing activities in Alaska.

Although these are separate pieces of legislation, passage of either bill would create a drastically different tax regime and business climate for the oil and gas industry in Alaska. Instituting a gas reserves tax and/or making changes contemplated in HB 63 to the Economic Limit Factor (ELF) on oil production taxes will have serious and lasting consequences - for the gas pipeline project itself, for the companies that would be directly impacted by the gas reserves tax, the companies that would be directly impacted by the changes in ELF contemplated in HB 63, and for the State of Alaska.

During AOGA's testimony on HB 63 last March, we stressed that this proposed change to ELF would be particularly egregious to the industry as it would be a structural tax increase of 27.5 percent. Additionally, the bill raises the maximum severance tax by 67%, from 15% to 25%. The Department of Revenue has briefed the legislature that, in order to maintain current production levels of just under 1 million barrels per day over the next decade, the state will need to see a doubling of investment dollars to Alaska to increase development of heavy/viscous oil, satellite fields, infield and wildcat production. HB 63 will act as a strong disincentive to new investment in all four areas.

HB 223, which would create, in terms of monetary impact, the most massive new tax in the United States, reflects a basic misunderstanding of how mega projects are developed, financed and approved. The $20 billion gas pipeline project is unique in its size and complexity and risk. HB 223, which is touted as a way of spurring the development of a natural gas pipeline, only adds to the economic risk of this mega-project, and has the potential of putting the project at risk. The fact is no project can be taxed into existence. A project can be taxed out of existence.

Billions of dollars of investment are required if Alaska is to have the gas pipeline, as well as the oil production needed to maintain oil production of 850,000 barrels per day. As mentioned above, the Department of Revenue has estimated that Alaska's oil and gas industry will need to invest $20-30 billion over the next decade in wildcat exploration, heavy oil, development of previously-discovered fields and satellite field development. This is in addition to the investment necessary to slow the production decline in existing fields and to the $20 plus billions of dollars necessary for the development of the gas pipeline. HB 223 and HB 63 would jeopardize these crucial investments that are vital in maintaining Alaska's base production and ensuring future years of Alaska's economy stabilized around new oil production and a gas pipeline.

These bills, individually and together, have very serious consequences for Alaska's future. As you discuss any potential changes to the current fiscal system, we would urge you to consider the following policy considerations:

1) Will a particular fiscal policy make Alaska more or less competitive for oil and gas investments?
2) Will a particular fiscal policy encourage or discourage investment in each of the four types of new production in Alaska?
3) Will a particular fiscal policy encourage investment in a gas pipeline?

We appreciate your consideration, and look forward to working with you this session.

Sincerely,

JUDITH BRADY
Executive Director

Cc: Representative Rokeberg
Representative Samuels
Representative Seaton
Representative Wilson
Representative Gruenberg
Representative Moses

NATIVE VILLAGE OD EAGLE
EAGLE VILLAGE IRA COUNCIL
P. O. BOX 19
EAGLE, ALASKA 99738

PHONE NO. (907) 547-2271
FAX NO. (907) 547-2287

January 4, 2006

Representative Eric Croft
Alaska State House of Representatives
State Capital, Room 400
Juneau, Alaska 99801-1182

RE: Gas Line Now Act

Dear Honorable Representative Croft:

On behalf of the Eagle Village Council, I want to thank you for giving me the opportunity to comment on HB 223, that Representative Harry Crawford and you sponsored. After reviewing the synopsis of HB-223, I wholeheartedly support this bill. I believe HB-223 is the mechanism that is needed to get the gas line up and running. I have heard that many of the oil and gas leases in the North Slope are undeveloped. This will be an incentive to develop and recover all the undeveloped gas that the oil companies leave in the ground.

Once we get a law such as this approved and passed, we will begin to see the oil companies eager to start the pipeline. If HB 223 is not passed and approved by the 24th Alaska State Legislature, then the people will have no other recourse but to put the initiative on the ballot. I also see at this time, when the state is financially struggling, that the revenues deriving from bill could be used to supplement some of those services that were cut.

If this tax, that is levied against the oil companies for non-production is put back into the Department of Natural Resources, then it will not benefit all Alaskans. It will only benefit the program managers. The only way it will benefit all Alaskans is to put the money back into some of the services-oriented programs that the people need. If this money goes back into the coffers of the Department of Natural Resources, I don't believe the people will see the results. It would be best used in programs that the people use and depend on, like energy assistance to offset the high rising fuel costs.

This is one way to start making the oil companies pay. With all of the potential producers in the state, I believe it is a one and only true way to get these companies to be responsive. They have had too much emphasis in all legislations. The State Constitution specifically states that any time money is derived from our natural resources, a percentage of the money will go into the permanent fund. In time of need, which is now, if HB 223 is passed, then the money derived from the 3 cents taxes could be used to serve the people now. It would be most beneficial to do a Needs Assessment and see where it is needed, now. I will support the money to be used for offsetting the energy costs.

Thank you for giving me the opportunity to comment on HB 223. I know and believe that if HB 223 is passed, all of the people will be able to stay warm and well during this time of need. In closing, I urge and ask all of you to support and vote for HB 223. It is a good bill and if passed, all the residents will benefit. If you have any questions, please feel free to call me at (907) 547-2271.

Isaac A. Juneby, Chief
Isaac A. Juneby
Eagle Village Council

C/C

Representative Harry Crawford
Alaska State House of Representatives
State Capital, Room 426
Juneau, Alaska 99801-1182

Representative David Guttenberg
Alaska State House of Representatives
State Capital, Room 13
Juneau, Alaska 99801-1182

"This moment will be a critical one in Alaska's future history. Development must not be confused with exploitation at this time. The financial welfare of the future state and the well being of its present and unborn citizens depend upon the wise administration and oversight of these developmental activities. Two very real dangers are present. The first, and most obvious, danger is that of exploitation under the thin disguise of development. The taking of Alaska's mineral resources without leaving some reasonable return for the support of Alaska governmental services and the use of all the people of Alaska will mean a betrayal in the administration of the people's wealth. The second danger is that outside interests, determined to stifle any development in Alaska which might compete with their activities elsewhere, will attempt to acquire great areas of Alaska's public lands in order NOT to develop them until such time as, in their omnipotence and the pursuance of their own interests, they see fit. If large areas of Alaska's patrimony are turned over to such corporations the people of Alaska may be even more the losers than if the lands had been exploited."

--E.L. "Bob" Bartlett

Delegate to Congress

Delivered to the Delegates of the Alaska Constitutional Convention

November 8, 1955

Alaska Oil and Gas Association

AOGA

121 W. Fireweed Lane, Suite 207
Anchorage, Alaska 99503-2035
Phone: (907)272-1481 Fax: (907)279-8114
Email: brady@aoga.org
Judith Brady, Executive Director

January 9, 2006

Representative Bruce Weyhrauch
State Capitol
Juneau, AK 99801-1182

RE: HB 223 & HB 63

Dear Representative Weyhrauch:

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Sincerely,

Judith Brady

JUDITH BRADY
Executive Director

Cc: Representative Rokeberg
Representative Samuels
Representative Seaton
Representative Wilson
Representative Gruenberg
Representative Moses

PRESENTATION ON
ALASKA GAS PIPELINE PROJECT

to Alaska State Legislative Budget & Audit Committee
August 31, 2005

Introduction of Econ One Research, Inc.

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Econ One Research, Inc.

- An economic research and consulting firm with offices in California (Los Angeles and Sacramento) and Texas (Houston and Austin)
- We provide consulting services in various industries, including petroleum and natural gas, regulated utilities, electricity, telecommunications, and computer software
- We have worked for:
  - A number of state governments on energy-related matters, including the States of Alaska, California, Hawaii, Louisiana, New Mexico, New York, and Texas
  - Federal government agencies, including the Department of Justice, the Federal Trade Commission, the Department of the Interior, and the President's Council of Economic Advisors
  - A number of foreign countries and international agencies, including the World Bank, Mexico, Nigeria, Turkey, and Tanzania on matters related to economic development and privatization of state-owned utilities
  - A number of companies in the petroleum and natural gas industries, including BP, Occidental Petroleum, ANR Pipeline, Koch Gateway Pipeline, Sempra Energy, KN Energy Corp., Lyondell-CITGO Refining, Total Petrochemicals U.S.A., Panhandle Eastern Corp., and ONEOK, Inc.

Dr. Jeffrey Leitzinger

- President of Econ One Research, Inc.
- Ph.D. in Economics from the University of California, Los Angeles
- Over 20 years of experience in economic research and consulting related to the petroleum and natural gas industries
- Economic expert for the State of Alaska on a number of occasions dating back to the 1980s
    - Major ANS royalty matters involving crude oil and natural gas
    - Investigation of the BP-ARCO merger
    - Charter Oil's purchase of State of Alaska royalty oil
- Served as expert for natural gas pipelines and gas producers on numerous occasions
- Testified on a number of occasions as an economic expert before the FERC and various state public utility commissions
- Published articles on natural gas markets and regulatory policies in the *Oil and Gas Journal*, the *Journal of Regulatory Economics*, the *Energy Law Journal,* and *Natural Gas*

Barry Pulliam

- Senior Economist with Econ One Research, Inc.
- Masters Degree in Economics from the Claremont Graduate School, with 17 years of experience consulting in the petroleum and natural gas industries
- Has consulted with or served as an economic expert for the State of Alaska on a number of occasions, including:
    - Several severance tax matters involving the valuation of crude oil
    - Operation of the TAPS Quality Bank in proceedings before the FERC and Alaska PUC
    - Merger and antitrust investigations
    - Recent arbitration between State and ExxonMobil involving crude oil royalties
- Consulted with the States of California, New Mexico, Texas, and Louisiana on economic issues related to the petroleum industry
- Consulted with federal government agencies, including the Department of the Interior and the Federal Trade Commission
- Co-author of two recent studies prepared for the Alaska Department of Natural Resources related to natural gas markets and royalty valuation issues

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Dr. Anthony Finizza

- Economist working in conjunction with Econ One Research, Inc.
- Ph.D. in Economics and Finance from the University of Chicago with over 30 years of experience working in the petroleum industry
- Chief Economist for ARCO from 1975 to 1998
- At ARCO, Dr. Finizza was in charge of petroleum price forecasting for the company's Long Range Planning Process and conducted scenario-planning exercises with senior management responsible for investment decisions
- Consulted with the California Energy Commission, the State of Hawaii, and the International Hydrogen Infrastructure Group (a consortium of private companies and the U.S. Department of Energy) on energy-related matters
- Currently teaches forecasting and modeling at the University of California, Irvine
- Published articles in *Business Economics*, *The Journal of Corporate Renewal,* and *The International Journal of Forecasting*
- Senior Fellow with the U.S. Association for Energy Economics
- Former President of the International Association for Energy Economics

Rick Harper

- Consultant to the natural gas industry working in conjunction with Econ One Research, Inc.
- Over 30 years of experience working for natural gas producers and pipelines
- Has held a number of senior management positions
  - 15 years with ARCO, serving in a number of positions in ARCO's natural gas business, including President of ARCO Gas
  - 10 years with Northwest Natural Gas Company, as Senior Vice President with responsibility for marketing, supply, transportation, trading, and storage
  - President and Chief Executive Officer of an oil and gas exploration and production company, Canor Energy, Ltd., located in Calgary, Alberta between 1994 and 2000
- Testified on matters related to gas markets and pipelines before the FERC, the National Energy Board of Canada, and regulatory commissions in Texas, California, and Oregon

Our Role

- Review and analyze the economic models constructed by the Administration to evaluate the various Gas Pipeline proposals

- Consult with the Legislative Budget and Audit Committee regarding economic aspects of contract terms proposed for inclusion in contracts being negotiated under the Stranded Gas Development Act

Our Work to Date

- Began work in Spring 2005
- Met with employees and consultants to the Department of Revenue and the Department of Natural Resources responsible for the development of Administration models
  - Employees of DOR included Roger Marks, Michael Williams, and Randy Hoffbeck
  - Employees of DNR included Antony Scott, William Nebesky, and Greg Bidwell
- In addition, we have interviewed DOR/DNR consultants, including Dr. Pedro van Meurs, Lukens Energy, Muse Stancil, and Goldman Sachs

Our Work to Date (cont'd)

- Reviewed and analyzed models prepared by DOR, DNR, and consultants
- Analyzed construction, assumptions, and various inputs to the models and the results generated
- Reviewed assumptions regarding:
  - Future gas, NGL, and oil prices
  - Likely delivery locations for Alaska gas
  - Pipeline tariffs
  - Capital costs
  - Operating costs
  - Production volumes over time
  - Operation of fiscal systems

Our Work to Date (cont'd)

- Considered the following questions:
  - Do the models do what they are intended to do?
  - Are they operationally sound?
  - Are there conceptual errors?
  - Are there mathematical errors?

Our Work to Date (cont'd)

- Interviewed a number of individuals active in the U.S. gas industry that are familiar with natural gas development, markets, and pipeline operations

- Analyzed published data, reports, and information regarding U.S. gas markets

Our Work to Date (cont'd)

- Reviewed data prepared by the Producers, TransCanada, the Port Authority, and the Administration that is at this time confidential
- That data is used in the Administration's economic models
- We are not free at this time to discuss or share that information publicly

Our Work to Date (cont'd)

- We also have reviewed various proposals for a Gas Pipeline project put forward by the Administration and the applicants under the Stranded Gas Development Act

- Most of these proposals are at this time confidential; we will not be discussing them today

Modeling

- Developed a model of the Gas Pipeline project using publicly available and non-confidential data; we will present results of that model later today

- If a Stranded Gas contract is put forward to the Legislature, it is our understanding that much of the data that is now deemed confidential will become public and we will be able to discuss and incorporate that information

Modeling (cont'd)

- We have analyzed the construction of a Gas Pipeline and development of the gas reserves under various alternatives, assuming that construction and development were to occur under the existing fiscal system

- The information we will present is derived from publicly available or non-confidential information

PRESENTATION ON
ALASKA GAS PIPELINE PROJECT

to Alaska State Legislative Budget & Audit Committee
August 31, 2005

Alaska Gas' Position in The Marketplace

Rick Harper
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Historical Context

- Low price levels of 1990s reflected an "over correction" to events of the 1980s
- Supply response is now more moderate than 1980s; no "runs for supply"
- Demand response is far less dramatic than 1980s; fuel switching by industrials is no longer a predominant demand driver.

Infrastructure Components

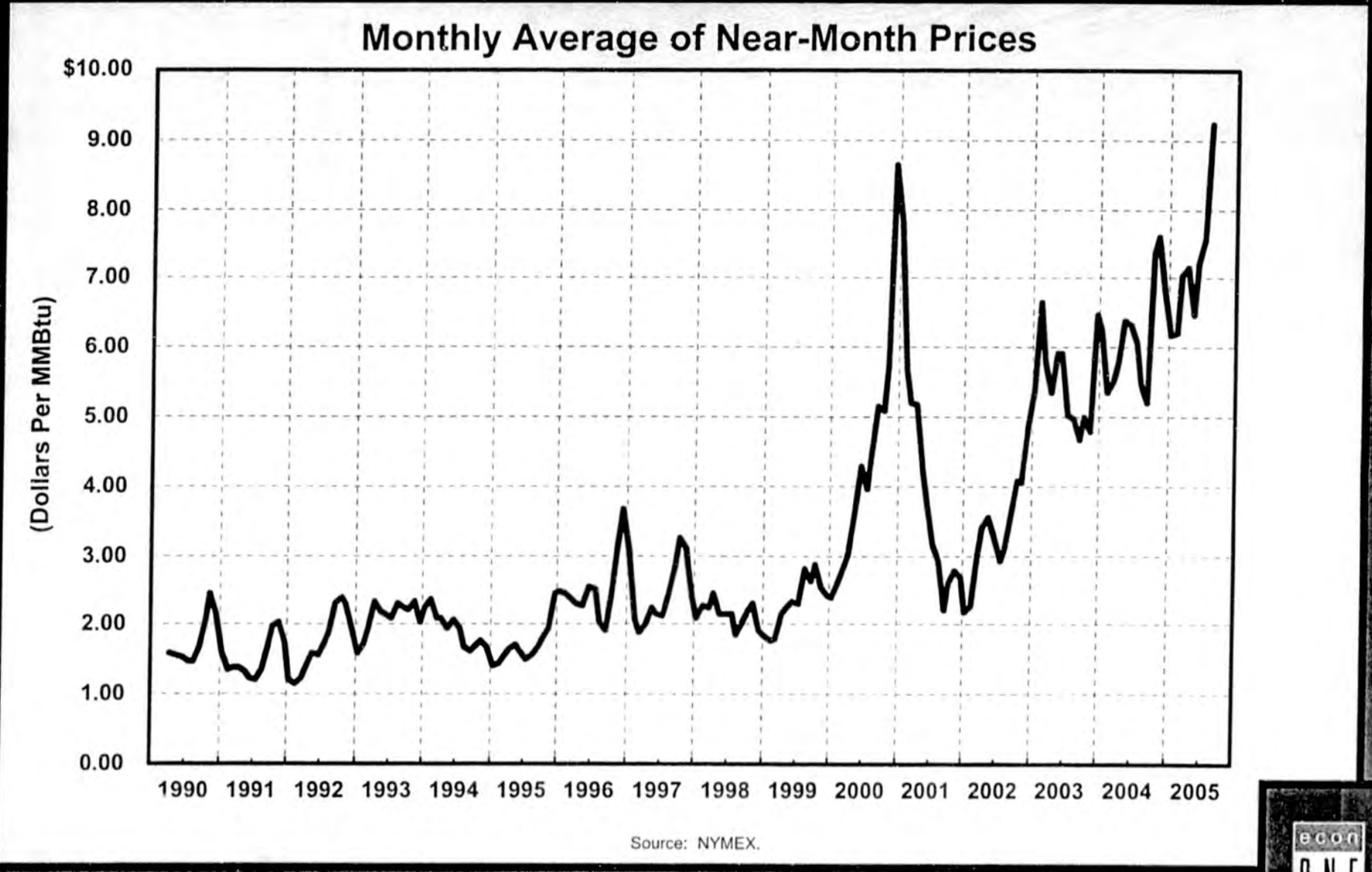
- The pipeline industry has consolidated; ownership is now more concentrated, for example:
  - ✓ TransCanada
  - ✓ Kinder Morgan
  - ✓ El Paso
- Producers continue to avoid interstate pipeline ownership
- Transportation improvements have mitigated physical bottlenecks in the U.S. and Canada
- Pipeline construction is now oriented to supplies in emerging basins (e.g. Deepwater Gulf of Mexico, Wyoming and W-5 in Alberta).

Price Environment

- Natural gas is less fungible than oil and natural gas prices are more seasonally dependant.
- "Paper" versus "physical" gas markets.
- NYMEX commodities prices.
- NYMEX gas price "strip" is now at unprecedented high levels.
- Current prices levels are not sustainable over the long term.

NYMEX Natural Gas Futures Prices

(April 1990 - August 2005)

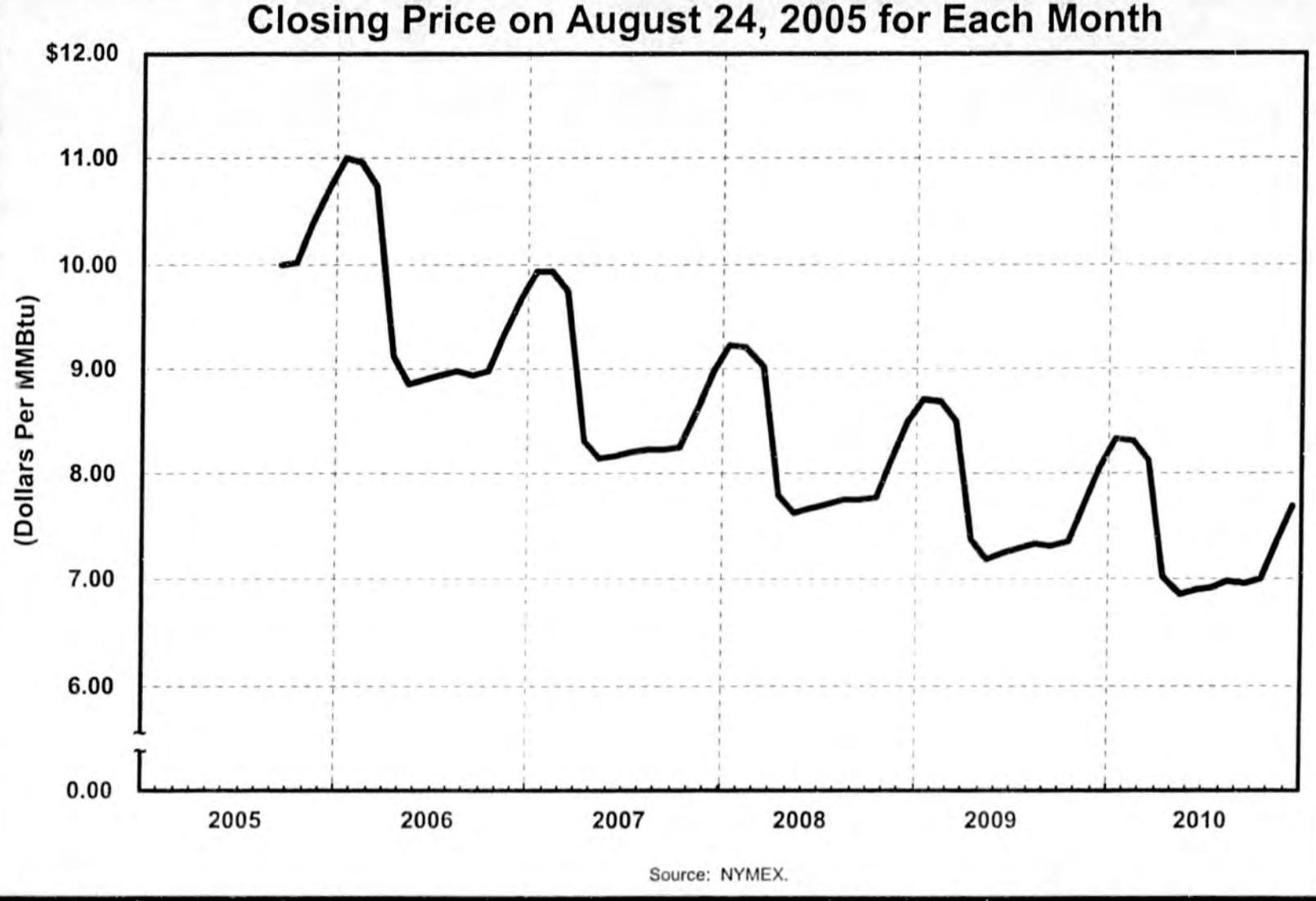


Source: NYMEX.

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NYMEX Natural Gas Futures Prices

(September 2005 - December 2010)

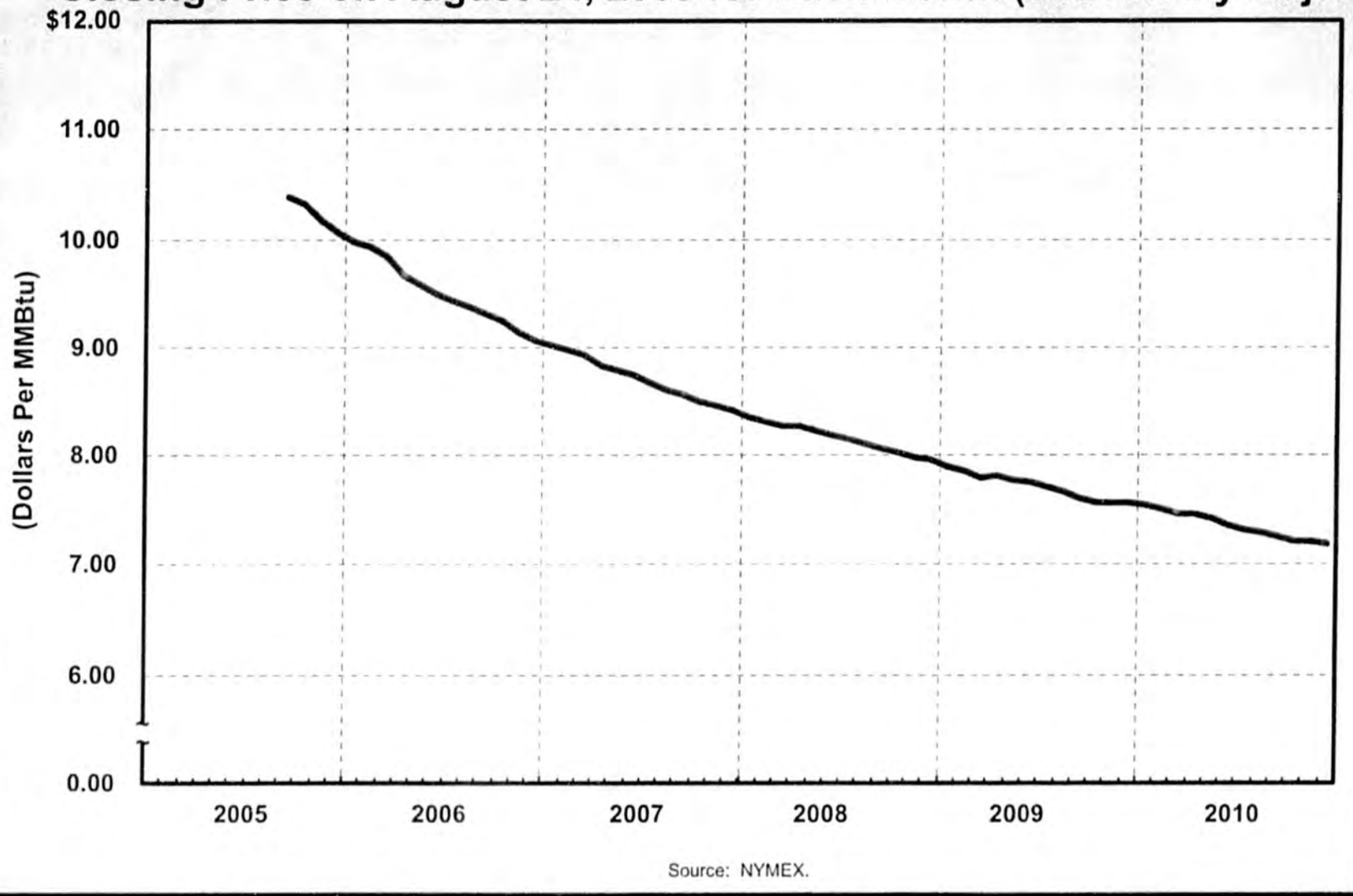


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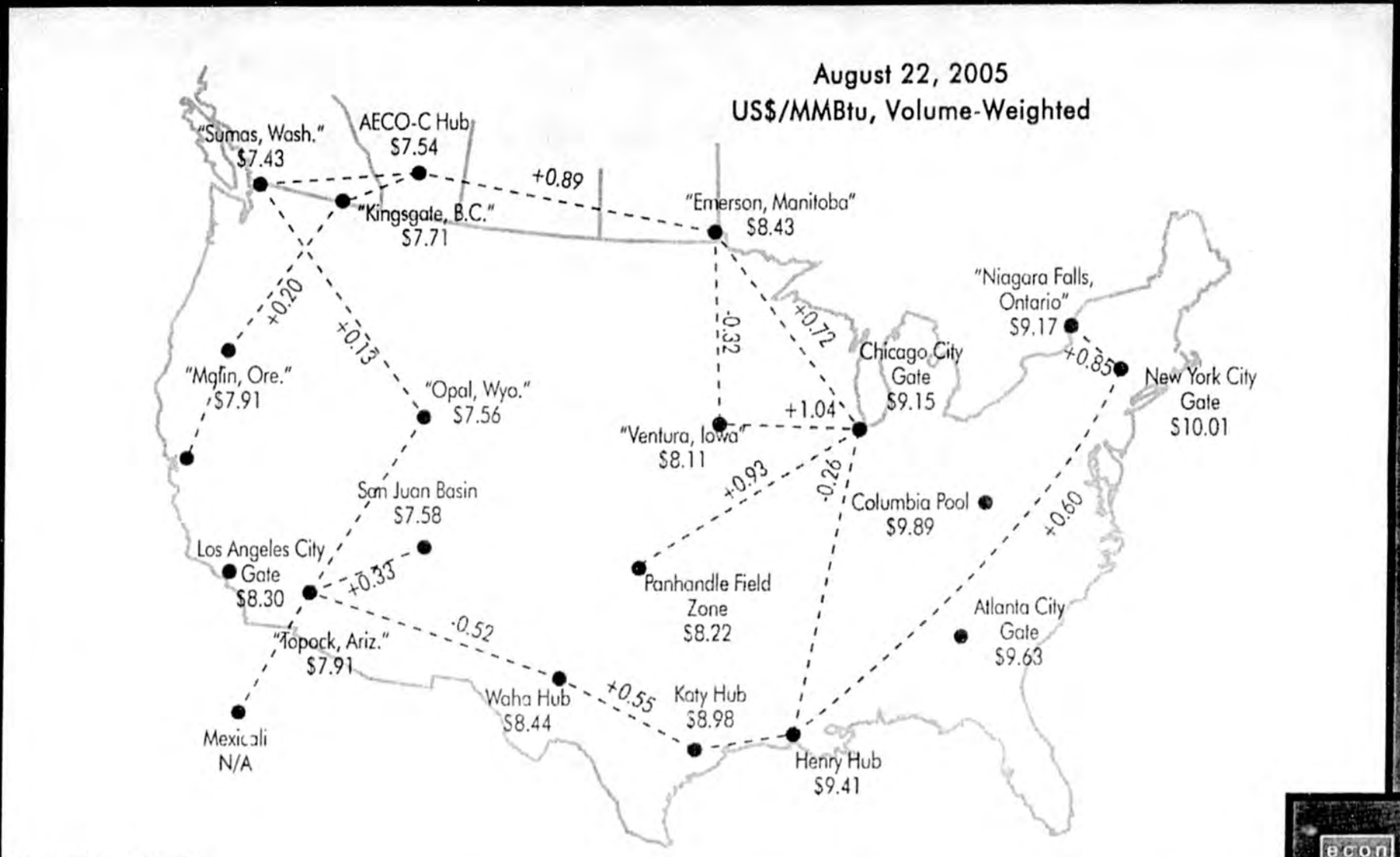
Price Environment

- Supply and demand responses have been slower and more moderate than in prior decades
- Non-traditional supplies (e.g. LNG, frontier gas) now play a more significant role
- Market expectation is for long term prices to return to a neighborhood around $5; there are indications that long term deals can be done today in the range of $5 to $7

"Basis" Dynamics

- Major North American natural gas market hubs:
  - ✓ Henry Hub (Louisiana)
  - ✓ Chicago
  - ✓ AECO (Alberta)
- Basis differentials (i.e., location based price differences) reflect inherent volatility from factors such as weather and power demand
- Trades in the OTC market have been important for the development of derivative products such as puts, calls, and collars

Natural Gas Prices at Major Gas Trading Locations and Selected City Gates



Source: Natural Gas Week.

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North Slope Gas

- North Slope gas will be "base loaded" into the market and will replace declining supplies in Alberta and the Gulf Coast
- LNG and short-lived fields will be marginal sources of supply
- Basis shifts will result in pipeline additions and reorientation of conventional supplies
- North Slope gas may help maintain feedstock industries in Western Canada by replacing leaner Albertan gas supplies

LNG

- Foreign LNG and Alaska gas supplies are neither directly competitive nor mutually exclusive
- Foreign LNG likely will become a marginal source of supply because it is fungible and readily able to respond to regional and continental price swings
- Foreign LNG and Alaskan gas will fill different niches and will each be part of the total supply mix from a portfolio perspective

Potential Markets for North Slope Gas

- There is a high degree of interest from non-utility electric generators seeking to match long term supplies to new projects, both physically and financially
- Local distribution companies serving the residential and commercial markets will play a key role as they seek dependable, economic long term supplies
- Post-Enron, the midstream segment will regenerate and will provide some liquidity and seasonal smoothing for base-loaded North Slope production

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Hedges and Derivative Products

- LNG and North Slope production have similar timing and pricing profiles
- Creative derivative products such as "costless collars" may offer an important benefit for stakeholders who need some degree of price certainty in a market which is somewhat illiquid in the out years

Conclusions

- Timing for North Slope gas entering the market is excellent
- North Slope gas is a logical addition to the North American natural gas and overall energy portfolio
- Adequate pricing support is apparent in the market

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ALASKA GAS PIPELINE PROJECT

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Natural Gas Prices and Tariffs

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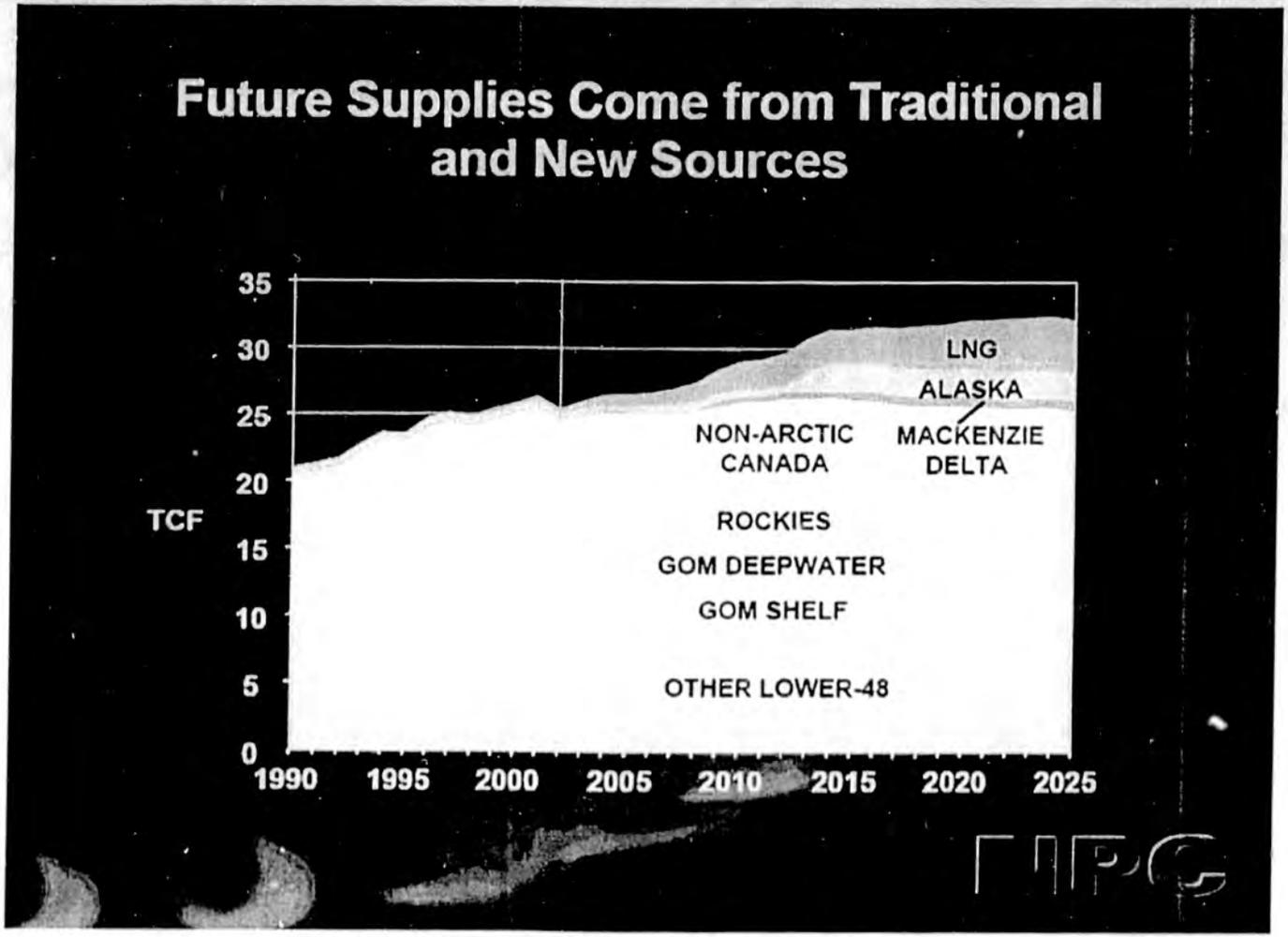
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The need for Alaskan Gas and LNG have been a feature of energy forecasts for many years



Source: National Petroleum Council "Balancing Natural Gas Policy" September 2003

Some Critical Uncertainties Facing Alaskan Gas

- Strength of natural gas market
- Extent of LNG penetration
- Competition of gas with alternative energy

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Future Natural Gas Markets

- North American natural gas supply tight
  - Lower-48 (L-48) continues decline
  - Canadian supply increases
  - LNG limited
- Electric Utilities growth
  - May face competition from coal at sustained $4-5/mmbtu gas prices
- Household/Commercial growth in line with income growth
- Industrial growth in line with GNP growth
- Little or no penetration in Transportation markets
- Current natural gas prices at cyclical high

U.S. Natural Gas Demand Outlook

- Half of incremental growth in natural gas consumption expected to be for electricity generation
  - 75% of new electricity generation capacity expected to be gas plants

U.S. Natural Gas Consumption
(TCF per year)

Sector	2005	2025	Change
Residential & Commercial	8.1	10.0	+1.9
Industrial	7.2	9.0	+1.8
Electric Utilities	5.2	9.4	+4.2
Transportation & Other	1.8	2.2	+0.4
Total	22.3	30.6	+8.3

Source: US DOE EIA "Annual Energy Outlook 2005" (January 2005)

LNG

- LNG needed in supply mix ~3-4 TCF/yr
- Can be delivered to market for $3.00 - 3.50/mmbtu, but will be sold at prevailing domestic gas prices
- Limited regasification facilities
- LNG is not marginal supply and will NOT set future gas prices. Set by needed higher cost L-48 supplies

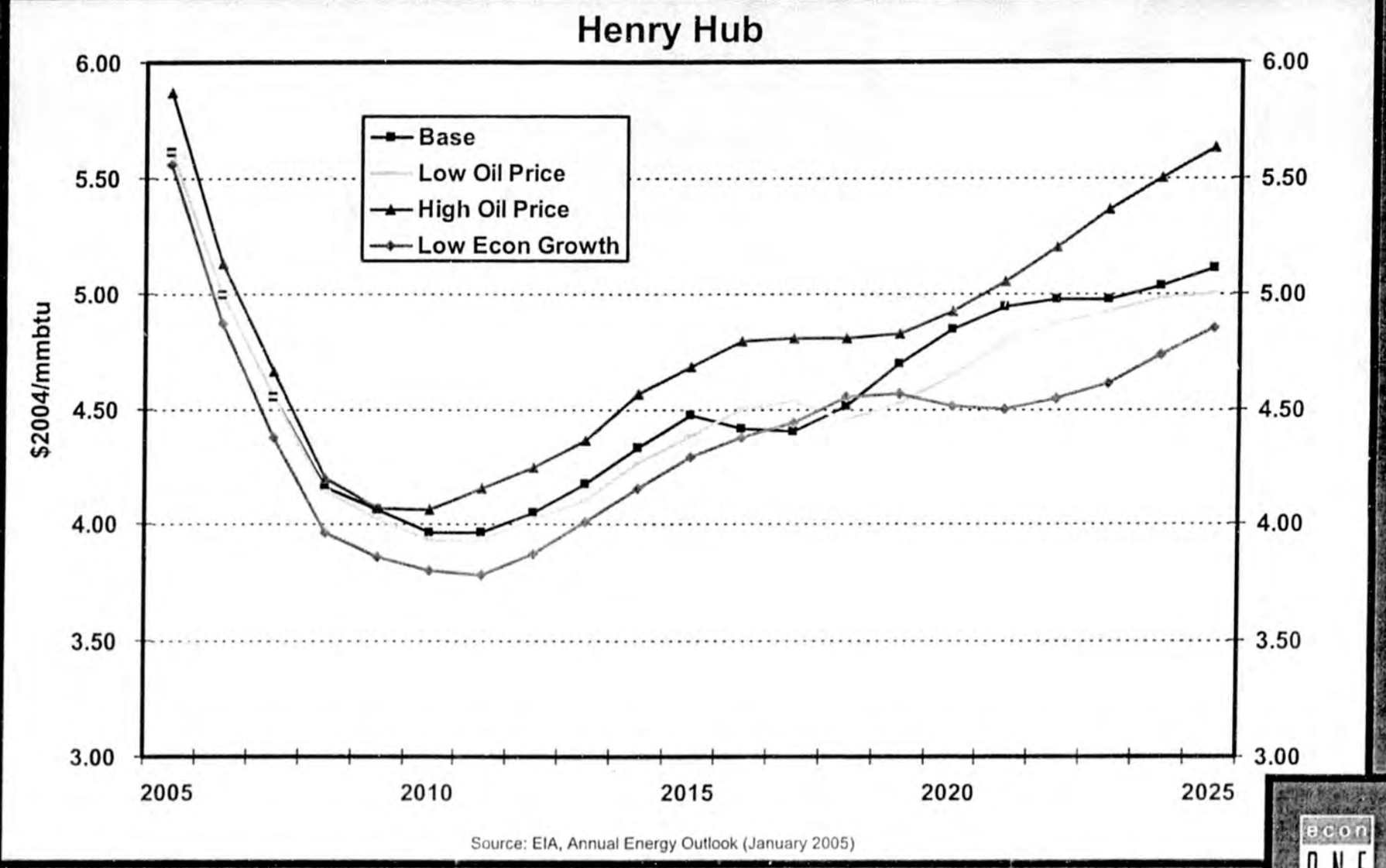
Alternative Energy Sources

- Natural gas faces threat from alternative power technologies when prices are high
  - CCGT (Combined-Cycle Gas Turbine) and with thermal coal break-even about $4/mmbtu
    - Coal has higher capital cost but low variable costs
  - Clean Coal IGCC (Integrated Gasification Combined Cycle) power technology competitive at sustained $4-5 /mmbtu gas price

Public Natural Gas Price Forecasts

- EIA's Annual Energy Outlook (AEO) – January 2005
  - Forecast of average wellhead prices (through 2025, converted to Henry Hub)
  - Alternative scenarios are too closely clustered for sensitivity use
- National Committee on Energy Policy (NCEP) – October 2003
  - Balanced commission of prominent energy stakeholders, including business, labor, academic, environmental, and political persons
  - Includes former chairman of Conoco
  - Developed Alternative Scenarios (through 2025) – AECO and Chicago hubs
  - Econ One has received permission to use details publicly and has created probability distribution of prices, allowing stress case use
- NYMEX Futures market
  - Natural gas contract (tied to Henry Hub) traded since 1990
  - Offers implied price forecast out 5 years – recently about $5.25 ($2005)
- Canadian gas consultants
  - Sproule (May 2005), GLG (April 2004), McDaniel (July 2004), AJM (2004)
  - Forecasts out to 2025
- Note: The Administration has done detailed (confidential) work on probabilistic forecasts

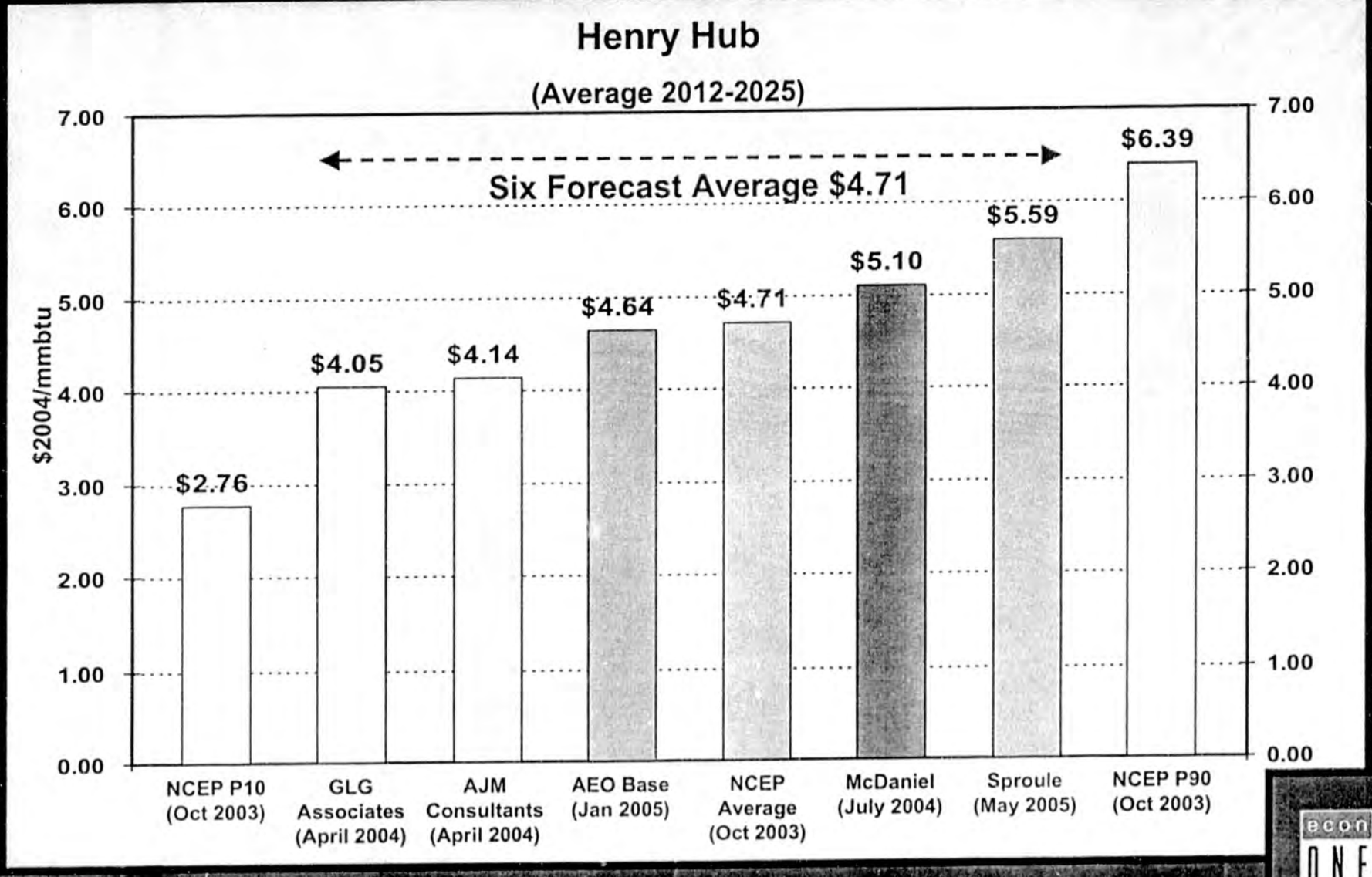
AEO 2005 Natural Gas Forecasts



Source: EIA, Annual Energy Outlook (January 2005)

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Alternative Natural Gas Price Forecasts

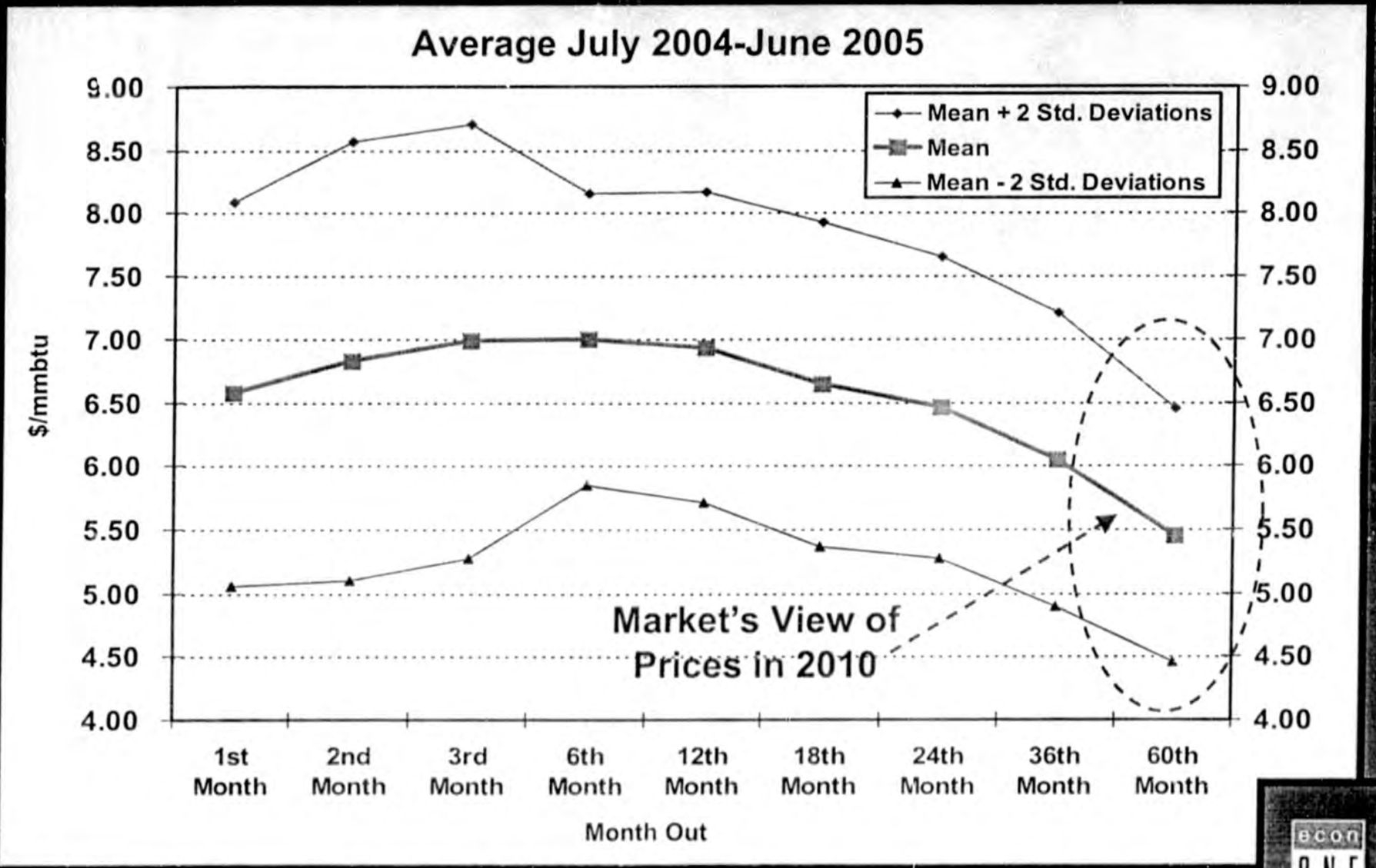


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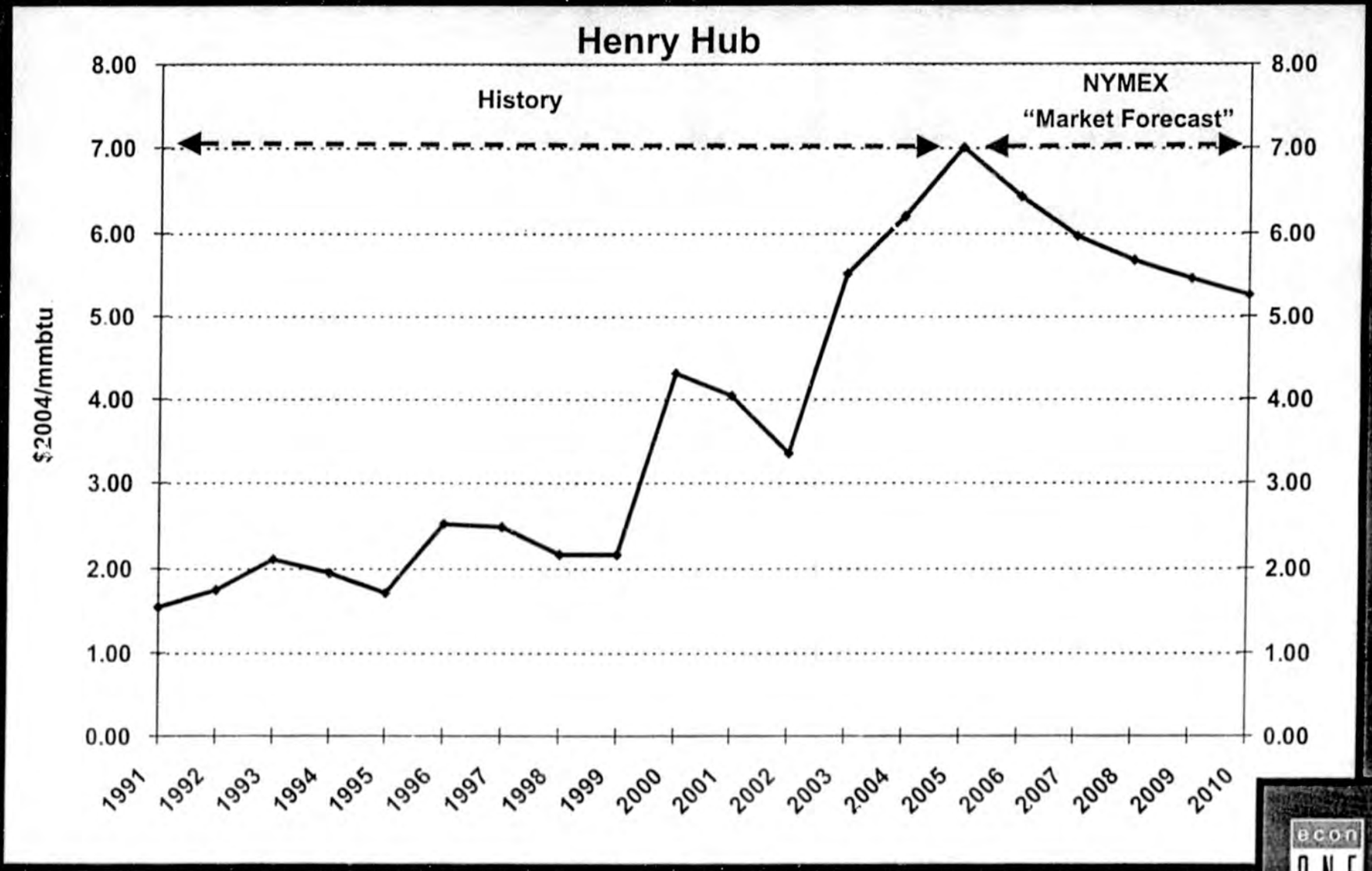
Forecasting Content of NYMEX Futures

- Reflects market's expectation of future gas prices, but …
  - Not highly accurate forecasts of gas prices
    - June 2002 NYMEX view of June 2005 was $3.72, actual was $6.56
  - They do outperform model based forecasts, e.g. EIA's AEO
    - Currently, future "strip" is well above EIA's forecast

NYMEX Natural Gas Futures Prices



Henry Hub Gas Prices: History and Market Forecast



Expected Price, High and Low/ Stress Price Cases

"Best Practices"

- Requires evaluation against a range of price cases, including a "Low Price" or "Stress Price" case in addition to an Expected Price case
  - Gasline project should have at least a "modest" return in the low price case

"Expected" Prices

- NYMEX offers a "Market Forecast" – recently, average about $5.00/mmbtu
- Average of publicly available forecasts – about $4.75/mmbtu

"Low/Stress" Price Test Case

- Rating agencies test projects against a sustained low price
  - Moody's and S&P currently using $3.75-4.00/mmbtu
- Can use the mean less two standard deviations (Mean–2σ) from NYMEX prices - recently about $4.00/mmbtu
- $3.50/mmbtu has been used in recent times, but now seems too low

"High" Price Case

- Can use the mean less two standard deviations (Mean+2σ) from NYMEX prices - recently about $6.00/mmbtu

Note: all prices are Real $2004/mmbtu in Chicago

Public Pipeline Costs

Billions of Dollars

	Producers* ($2001)	Producers ($2005)	Tristone Capital ***($2005)
Gas Treatment Plant	2.6	2.8	
Pipeline: Alaska	4.4	4.8	
Pipeline: Alaska to Alberta (Gordondale) **	4.8 } 7.2	5.2 } 7.8	
Pipeline: Alberta (Gordondale to Vegreville) **	2.4 }	2.6 }	
NGL Plant	.6	.7	
Total: North Slope to Alberta	14.8	16.0	18.0
Pipeline: Alberta to Chicago	4.6	5.0	6.0
Total: North Slope to Chicago	19.4	21.0	24.0

*$125 M feasibility study as reported by Producers, June 2004. Range ±20%.

** Producers did not split out Gordondale/Vegreville capital. Estimated split on basis of mileage.

*** "Monetizing Northern Frontier Gas," Tristone Capital, May 2005

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Pipeline Tariffs

Assumes Project ends at Gordondale, Alberta
$/mmbtu

	Estimated Tariff*
Gas Treatment Plant	.29
Pipeline: Alaska (includes PT Feeder)	.48
Pipeline: Alaska to Gordondale, Alberta	.50
AECO Entry Fee	.16
Total Pipeline Charges: North Slope to Market (Alberta)	1.14
Total Pipeline Charges + GTP: North Slope to Market (Alberta)	1.43 ± 20%

* Assumes publicly available capital, 4.2 bcf/d sales, financial parameters (80/20 Debt/Equity, Allowed Rate of Return 14% US, 12% Canada, Debt 5.0%)

Implied Netbacks Under Alternative Gas Prices

Assumes Project ends at Gordondale, Alberta

Initial Year Values - $/mmbtu

	"Stress" Price	"Forecast" Price	"Futures Market" Price	"High" Price
Chicago Price	$4.00	$4.75	$5.00	$6.00
Chicago/AECO Differential (exclusive of AECO entry fee)	.90	.90	.90	.90
AECO Entry Fee	.16	.16	.16	.16
Pipeline + GTP +PT Feeder	1.26	1.26	1.26	1.26
Netback at Inlet to Pipeline	$1.68	$2.43	$2.68	$3.68
Operating Costs & Fuel Use	.07	.08	.09	.11
Royalty and Taxes	.34	.49	.54	.74
Netback to Producers	$1.27	$1.86	$2.05	$2.83

PRESENTATION ON
ALASKA GAS PIPELINE PROJECT

to Alaska State Legislative Budget & Audit Committee
August 31, 2005

Return on Capital & Cost of Capital:
Petroleum & Natural Gas Pipeline Companies

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Commonly Used Accounting Measures of Profitability

- Return on Capital Employed (ROCE)
- Return on Shareholder Equity (ROE)

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Return on Capital Employed

- Capital Employed = Book Value of Debt + Book Value of Equity
- The *Return on Capital Employed* (ROCE) of a firm measures its operating efficiency in generating profits from the average level of capital employed, excluding the potential beneficial effects of financing
- ROCE is one of the petroleum industry's most widely used profitability measures
- $$\text{ROCE} = \frac{\text{Earnings Before Interest \& Taxes (EBIT) x (1 - Tax Rate)}}{\text{Book Value of Debt + Book Value of Equity}}$$

or

$$= \frac{\text{Operating Profit Before Financing Costs}}{\text{Capital Employed}}$$

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Return on Shareholder Equity

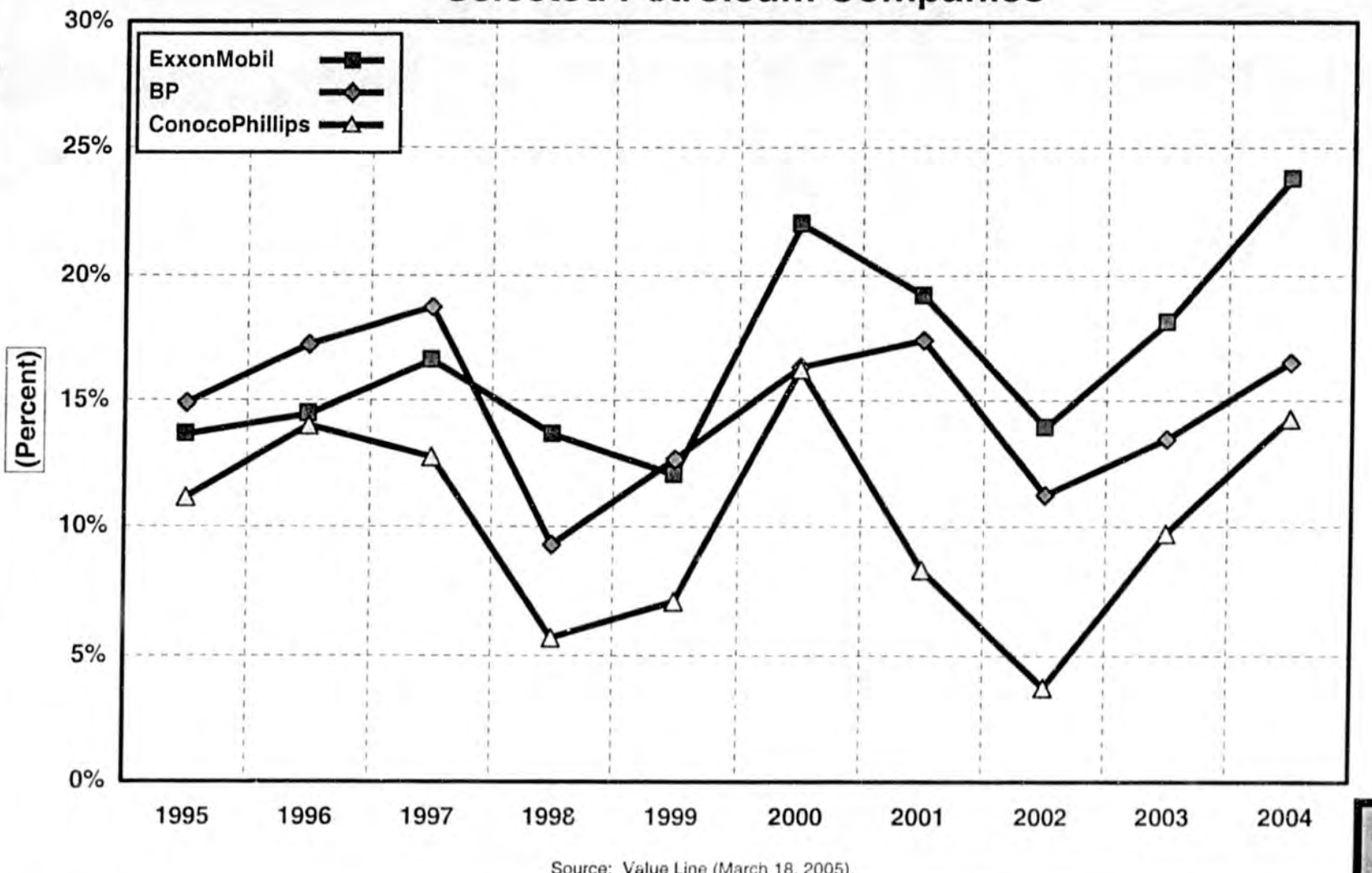
- The *Return on Shareholder Equity* (ROE) measures the firm's profitability from the perspective of an equity investor (e.g., shareholder)

- Unlike ROCE, ROE includes the impact of debt financing and the ability of the firm to use "leverage" to benefit its shareholders

- $$\text{ROE} = \frac{\text{Net Income}}{\text{Book Value of Common Equity (or Stock)}}$$

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Return on Capital Employed
(1995 - 2004)



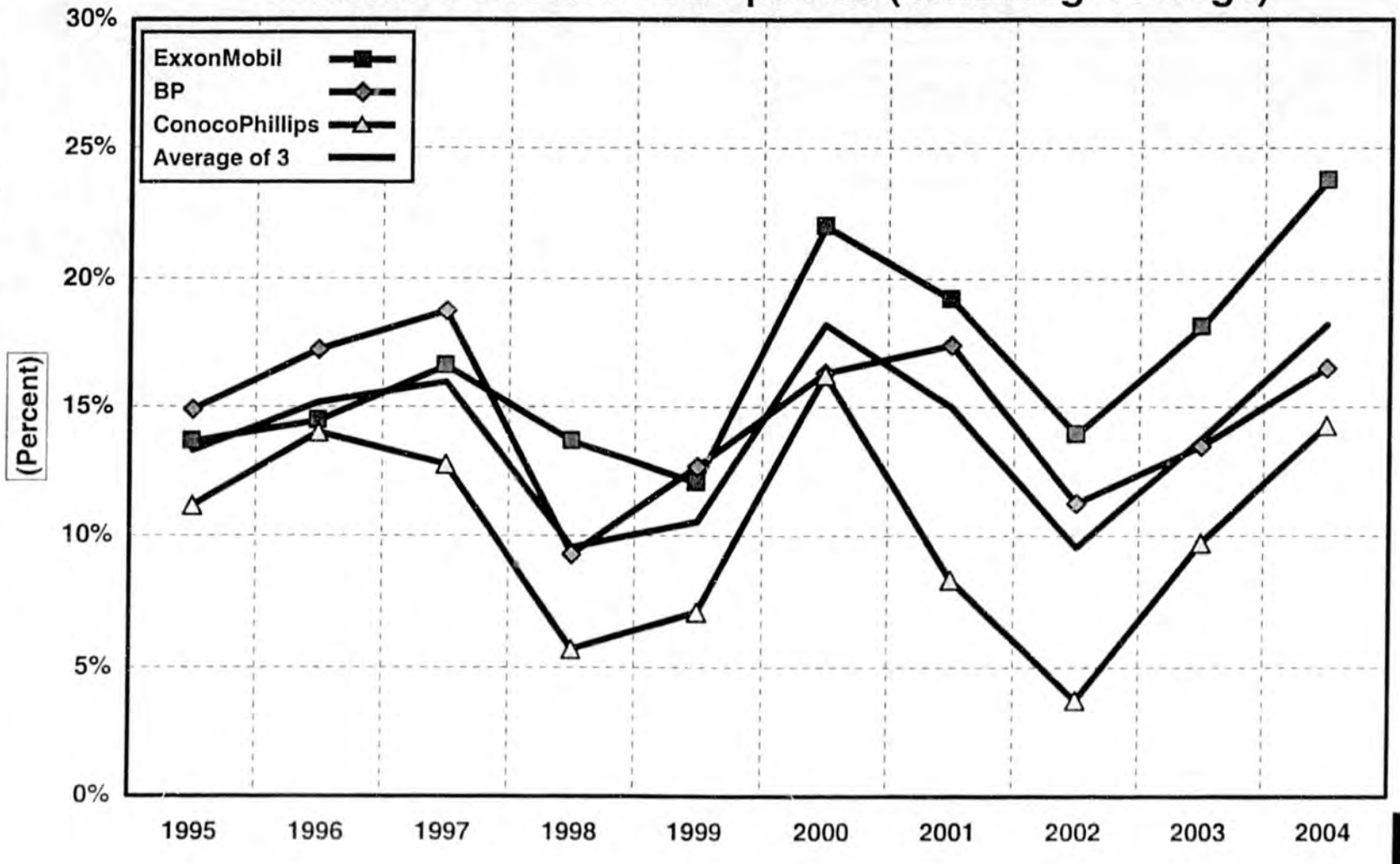
Source: Value Line (March 18, 2005).

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Return on Capital Employed

(1995 - 2004)

Selected Petroleum Companies (Including Average)

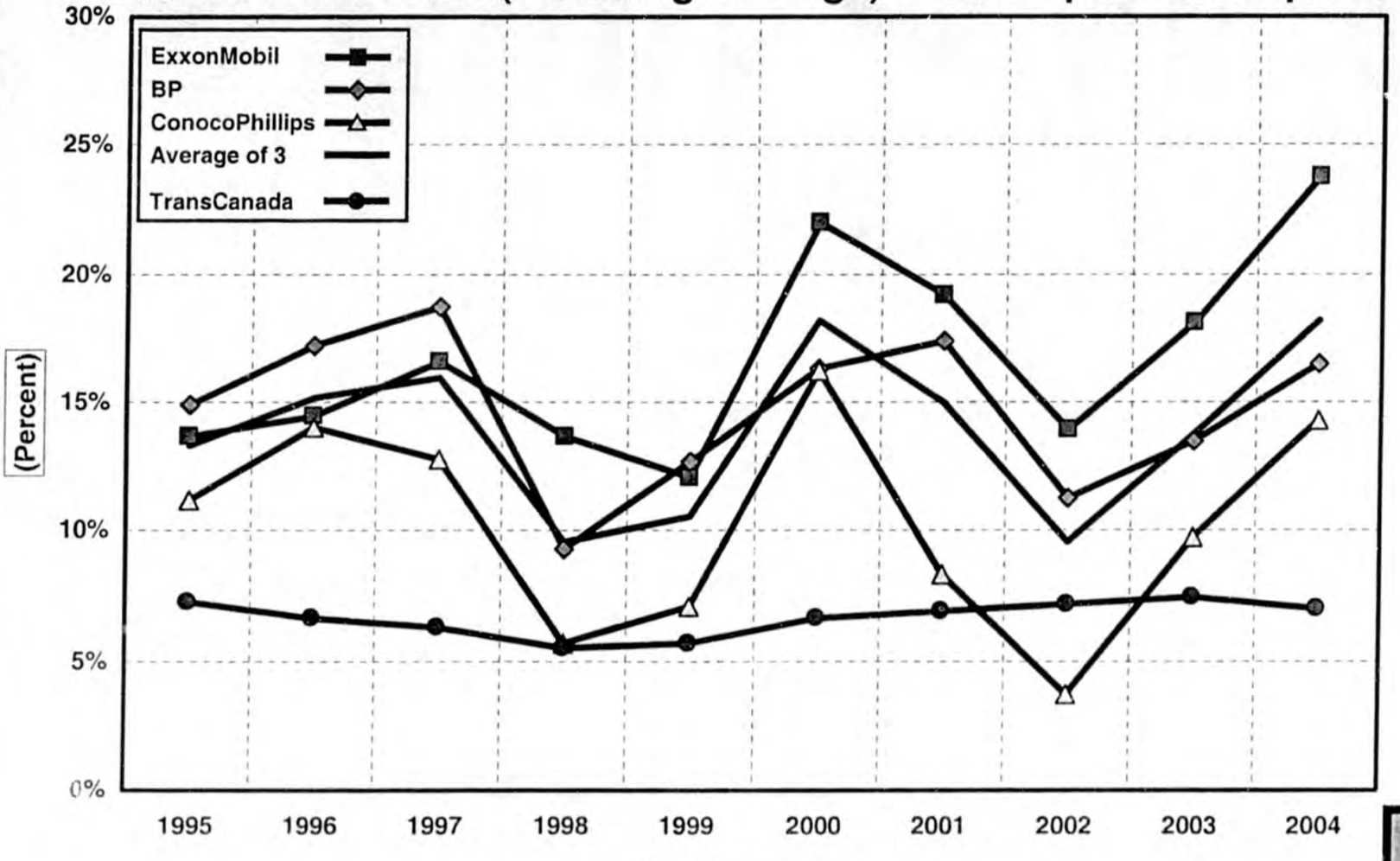


Source: Value Line (March 18, 2005).

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Return on Capital Employed
(1995 - 2004)

Selected Petroleum (Including Average) & Gas Pipeline Companies

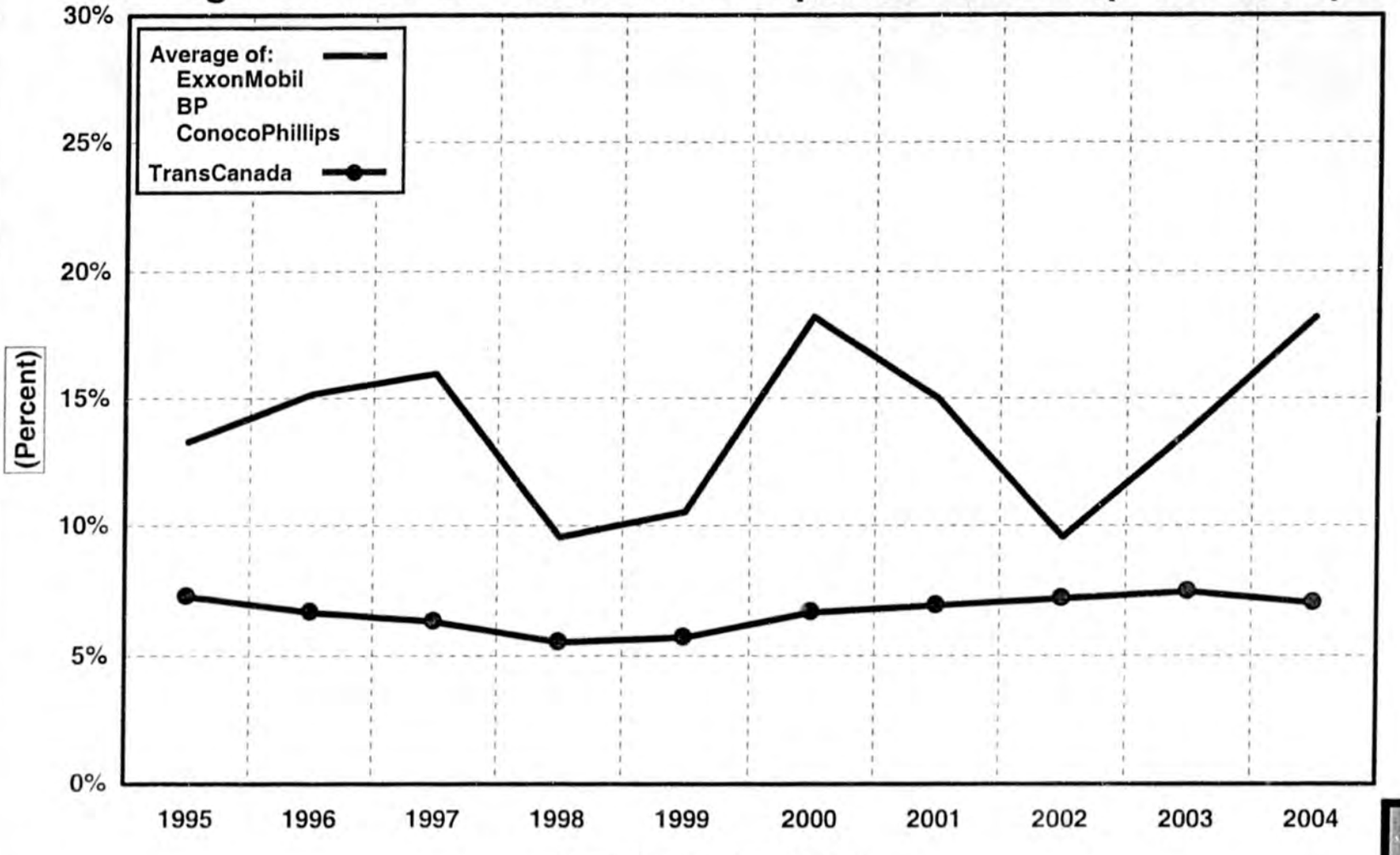


Source: Value Line (March 18, 2005).

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Return on Capital Employed
(1995 - 2004)

Average of Selected Petroleum Companies & Gas Pipeline Company

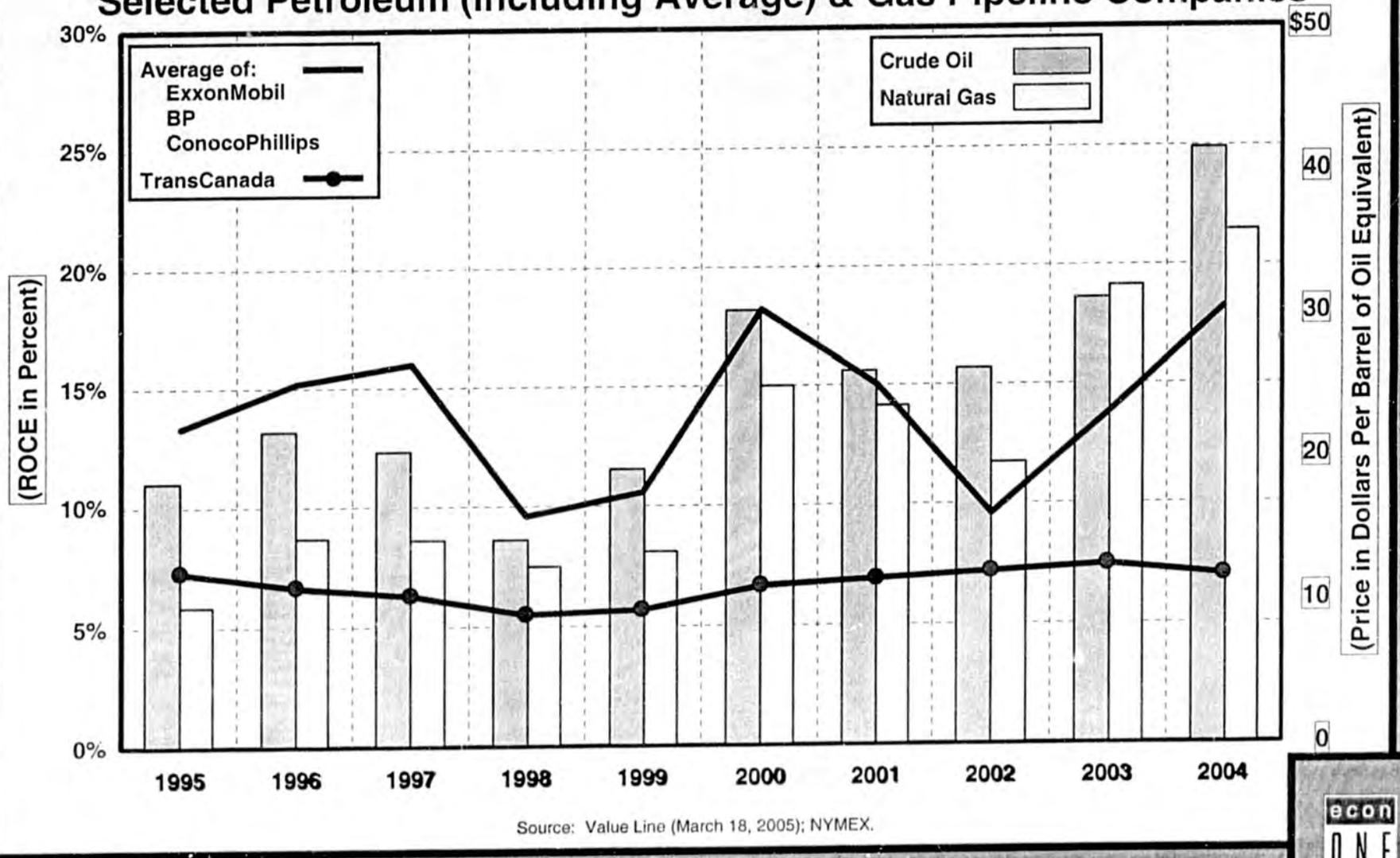


Source: Value Line (March 18, 2005).

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Return on Capital Employed
(1995 - 2004)

Selected Petroleum (Including Average) & Gas Pipeline Companies



Source: Value Line (March 18, 2005); NYMEX.

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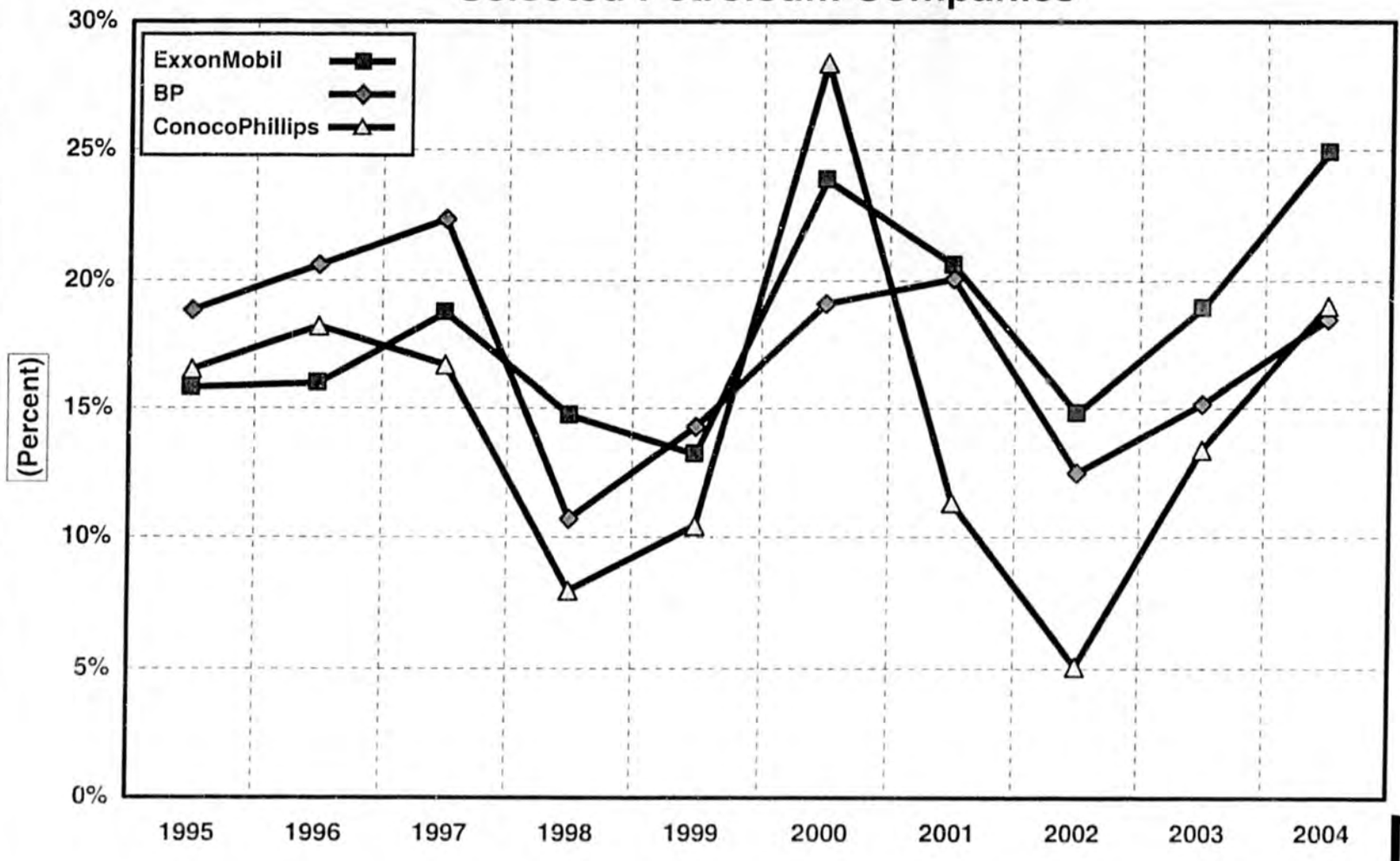
Return on Capital Employed
(1995 - 2004)

	5-Year Average (Percent) (1)	10-Year Average (Percent) (2)
ExxonMobil	19.4%	16.8%
BP	15.0	14.8
ConocoPhillips	10.5	10.3
Average of Above 3	15.0	14.0
TransCanada	7.1	6.7
NYMEX Crude Oil ($/Bbl.)	$30.96	$24.96
NYMEX Natural Gas ($/MMBtu)	$4.68	$3.46

Source: Value Line (March 18 2005); NYMEX.

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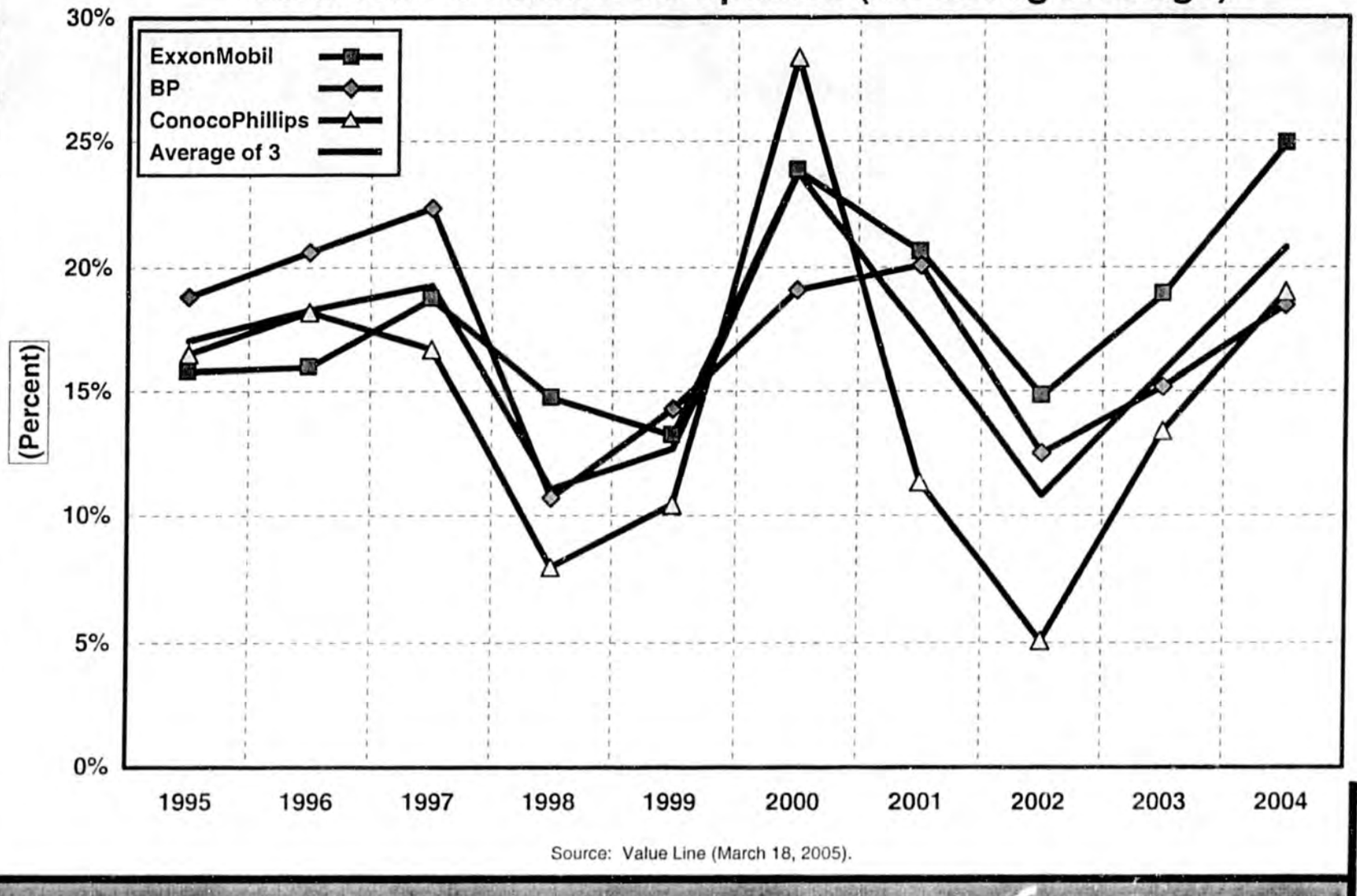
Return on Shareholder Equity
(1995 - 2004)



Source: Value Line (March 18, 2005).

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Return on Shareholder Equity
(1995 - 2004)

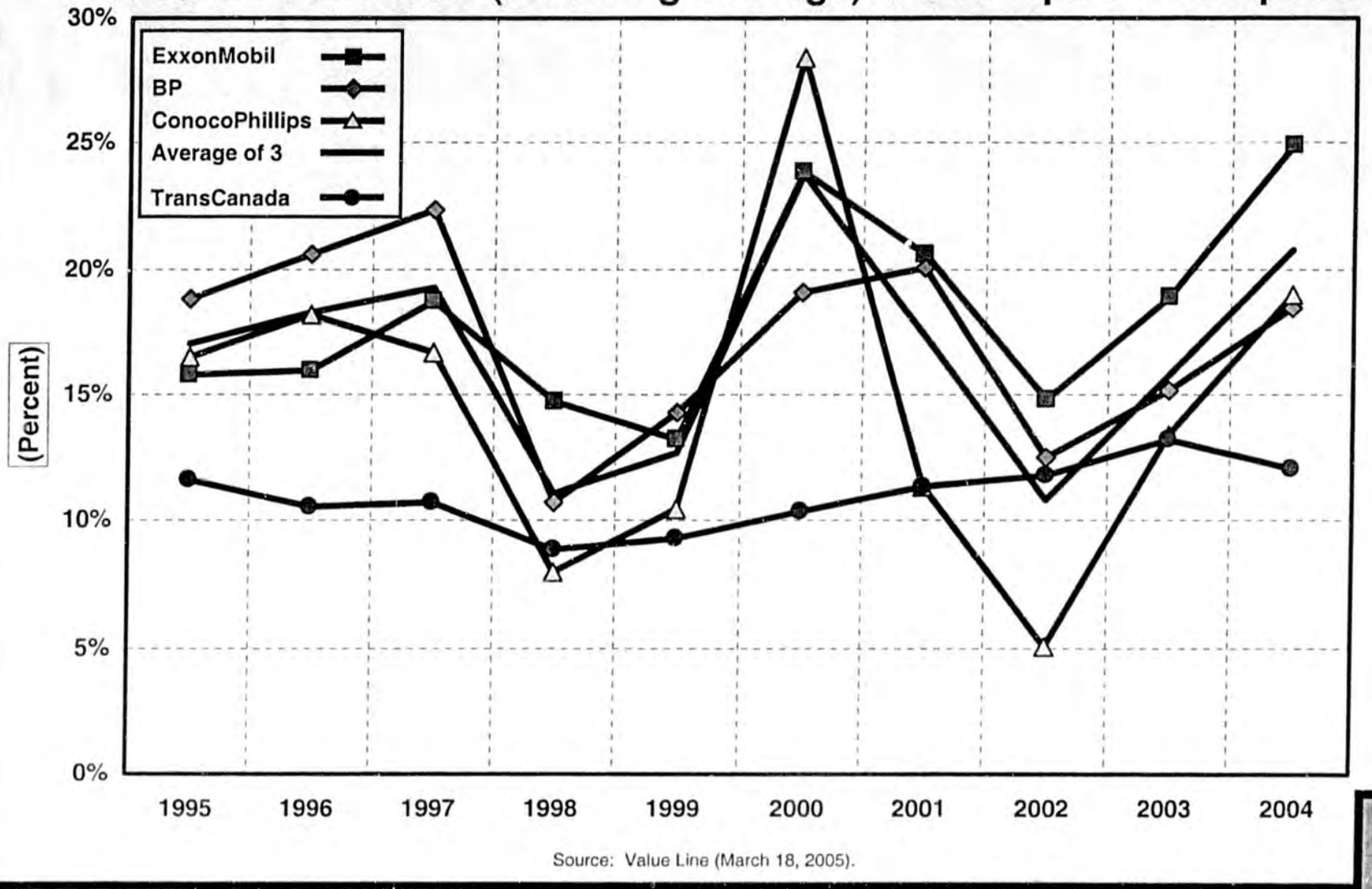


Source: Value Line (March 18, 2005).

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Return on Shareholder Equity
(1995 - 2004)

Selected Petroleum (Including Average) & Gas Pipeline Companies

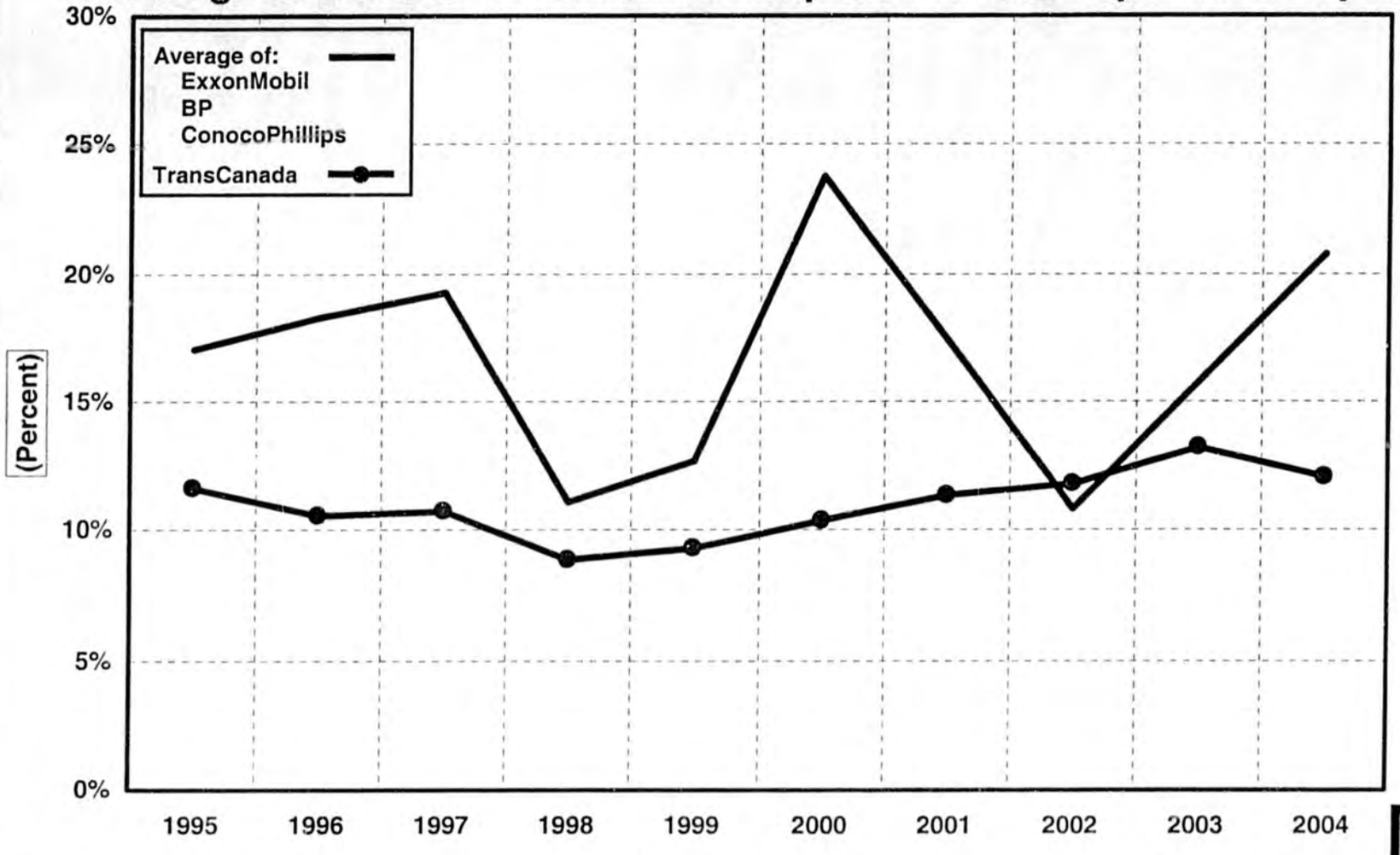


Source: Value Line (March 18, 2005).

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Return on Shareholder Equity
(1995 - 2004)

Average of Selected Petroleum Companies & Gas Pipeline Company



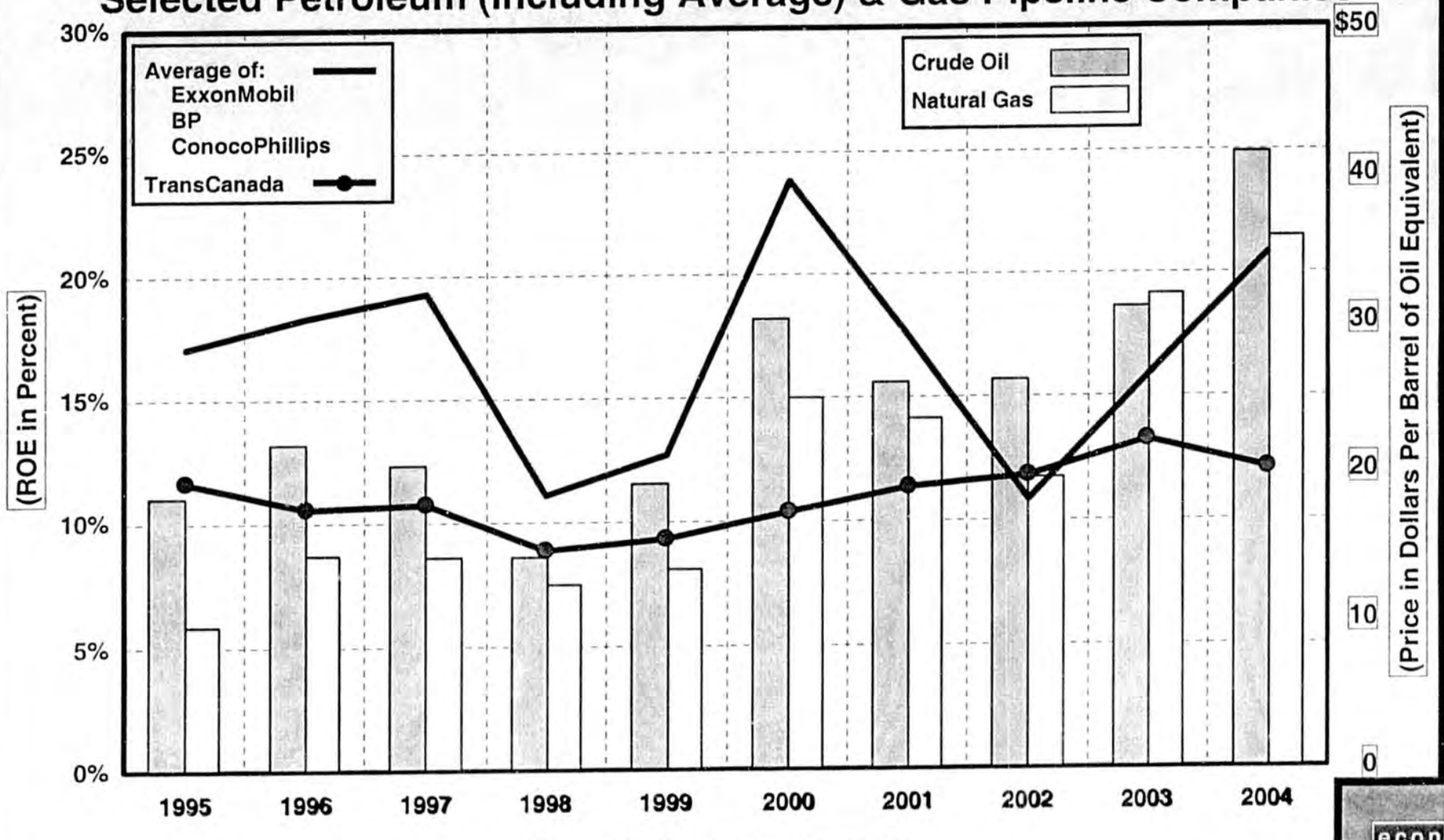
Source: Value Line (March 18, 2005).

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Return on Shareholder Equity

(1995 - 2004)

Selected Petroleum (Including Average) & Gas Pipeline Companies



Source: Value Line (March 18, 2005); NYMEX.

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Return on Shareholder Equity
(1995 - 2004)

	5-Year Average	10-Year Average
	(Percent)	
	(1)	(2)
ExxonMobil	20.6%	18.2%
BP	17.1	17.2
ConocoPhillips	15.5	14.7
Average of Above 3	17.7	16.7
TransCanada	11.8	11.0
NYMEX Crude Oil ($/Bbl.)	$30.96	$24.96
NYMEX Natural Gas ($/MMBtu)	$4.68	$3.46

Source: Value Line (March 18, 2005); NYMEX.

Weighted Average Cost of Capital

- The *Weighted Average Cost of Captial* (WACC) is the average cost to the firm of attracting capital
- WACC is equal to the average cost of the firm's debt (D) and equity (E)
- WACC depends on the proportion of debt and equity that comprise the firm's capital structure
- WACC is measured based on the market value of the firm's debt and equity, not the book value

Weighted Average Cost of Capital

- WACC is measured based on "after tax" costs
- After-tax cost of debt is lower than pre-tax cost because interest payments are tax-deductible
- After-tax Cost of Debt = Borrowing Cost (%) x (1 - Tax Rate)
- Example:
  - Borrowing Cost = 8%
  - Tax Rate = 35%
  - Cost of Debt = 8% x (1 - 35%) = 5.2%

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Weighted Average Cost of Capital

- After-tax cost of equity is the return required by investors for the firm's common stock
- Cost of equity is commonly measured using the Capital Asset Pricing Model (CAPM)
- Cost of equity under the CAPM formula depends on:
  - Risk-free returns (Federal government bonds)
  - Market equity risk premium (e.g., S&P 500 return over the risk-free rate)
  - The risk of the particular firm relative to the market or "beta"

Weighted Average Cost of Capital

- Examples of cost of equity:

1. Firm with risk equal to market-wide average:

Risk-free rate	= 5%
Market risk premium	= 7%
Company specific beta	= 1.0
Cost of equity	= 5% + (7% x 1.0) = 12.0%

2. Firm with risk equal to 1/2 market-wide average:

Risk-free rate	= 5%
Market risk premium	= 7%
Company specific beta	= 0.5
Cost of equity	= 5% + (7% x 0.5) = 8.5%

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Weighted Average Cost of Capital

- Betas for companies in petroleum and natural gas pipeline industry are typically less than 1.0, reflecting less than market-average risk
- 2004 betas for selected companies range between 0.25 and 0.83

ExxonMobil	= 0.41
BP	= 0.61
ConocoPhillips	= 0.83
TransCanada	= 0.25

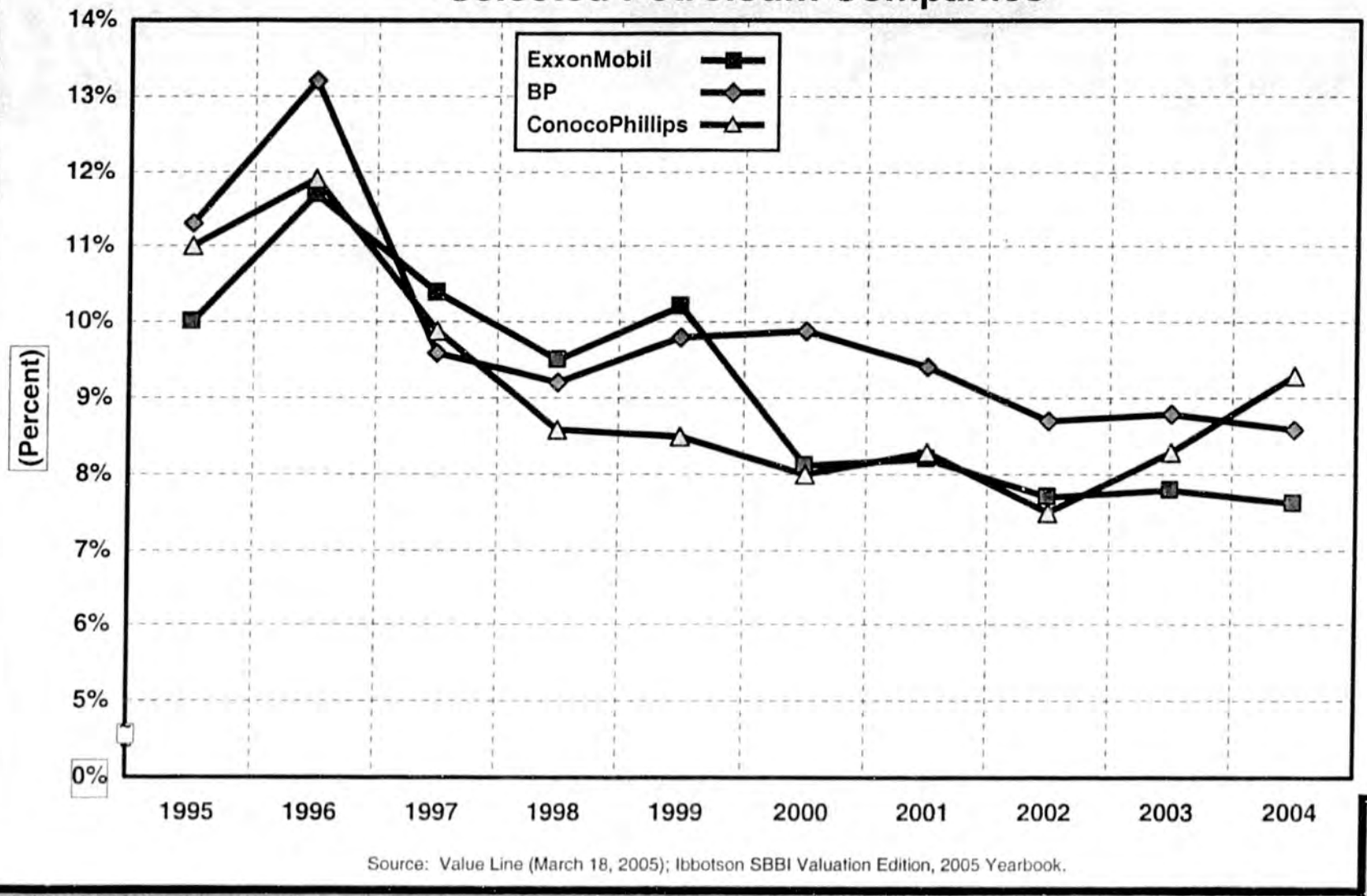
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Weighted Average Cost of Capital

- WACC is after-tax cost of debt and equity weighted by the proportion of each in firm's capital structure
- 2004 cost of capital for selected companies:

	Exxon Mobil	BP	Conoco Phillips	Trans Canada
Cost of debt	5.6%	5.9%	6.7%	6.7%
Tax rate	38.6%	34.5%	43.6%	36.8%
After-tax cost of debt	3.5%	3.9%	3.8%	4.2%
After-tax cost of equity	7.8%	9.2%	10.8%	6.6%
Debt %	2.7%	10.5%	21.9%	48.7%
Equity %	97.3%	89.5%	78.1%	51.3%
WACC	7.6%	8.6%	9.3%	5.5%

Weighted Average Cost of Capital
(1995 - 2004)



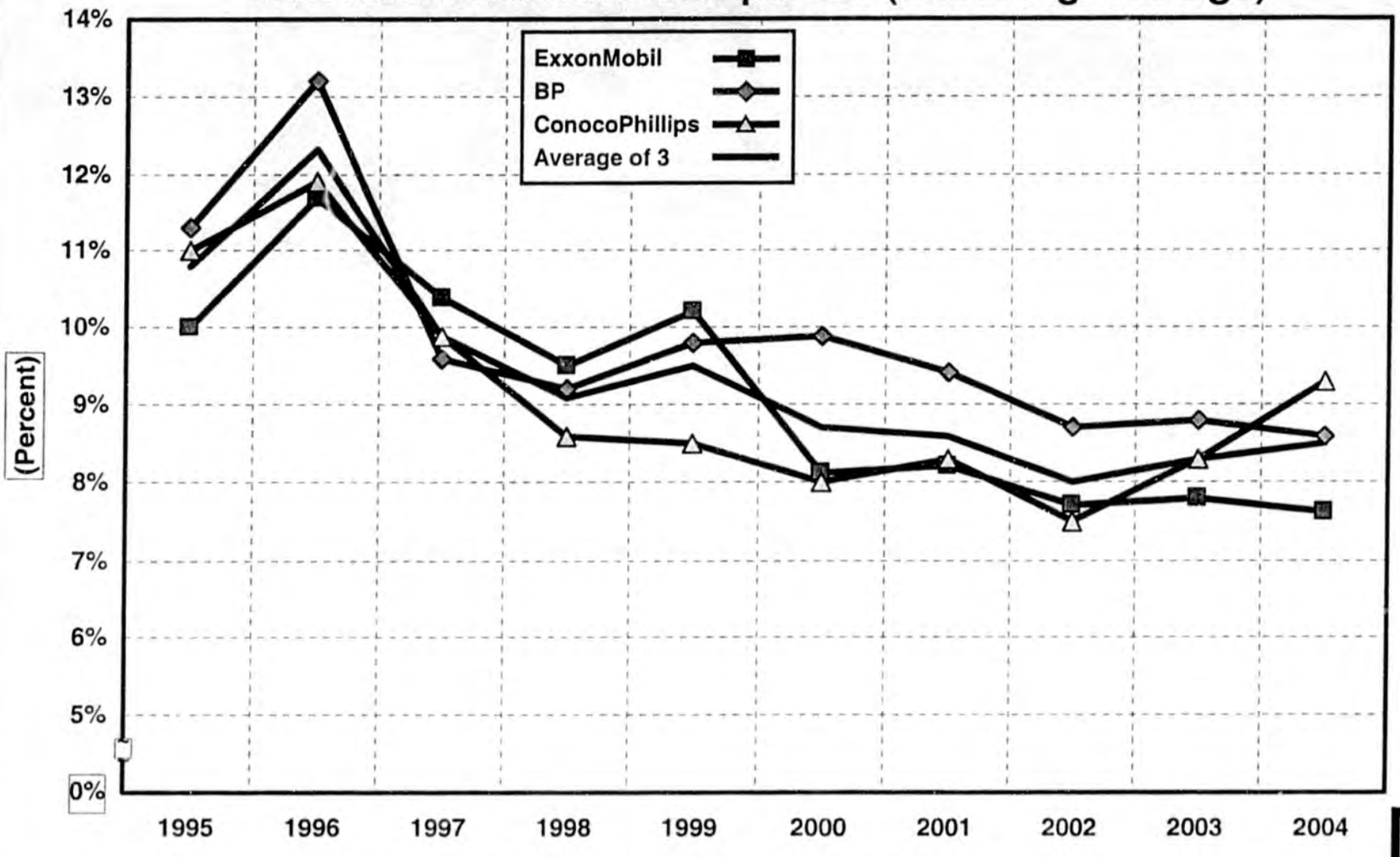
Source: Value Line (March 18, 2005); Ibbotson SBBI Valuation Edition, 2005 Yearbook.

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Weighted Average Cost of Capital

(1995 - 2004)

Selected Petroleum Companies (Including Average)

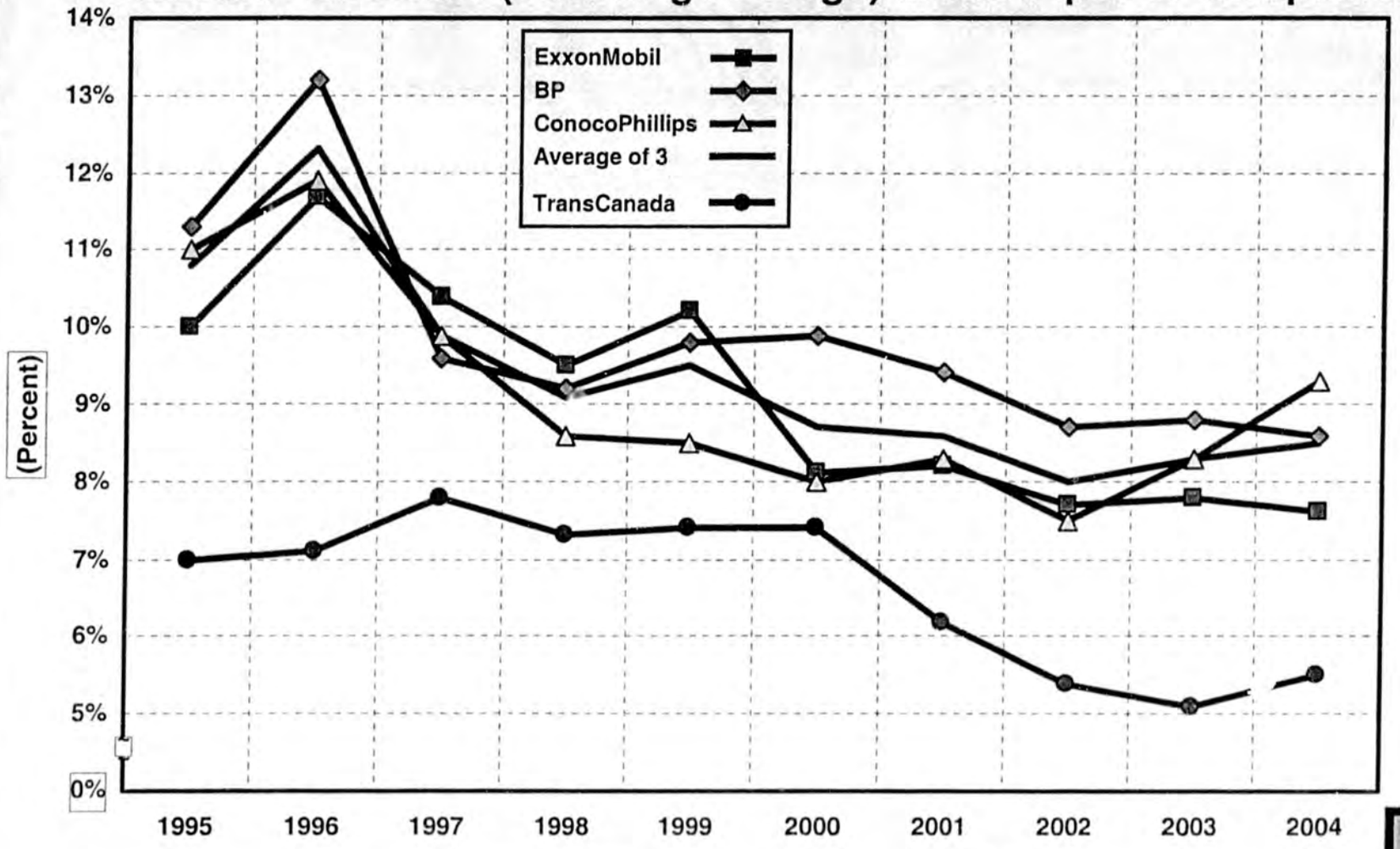


Source: Value Line (March 18, 2005); Ibbotson SBBI Valuation Edition, 2005 Yearbook.

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Weighted Average Cost of Capital
(1995 - 2004)

Selected Petroleum (Including Average) & Gas Pipeline Companies



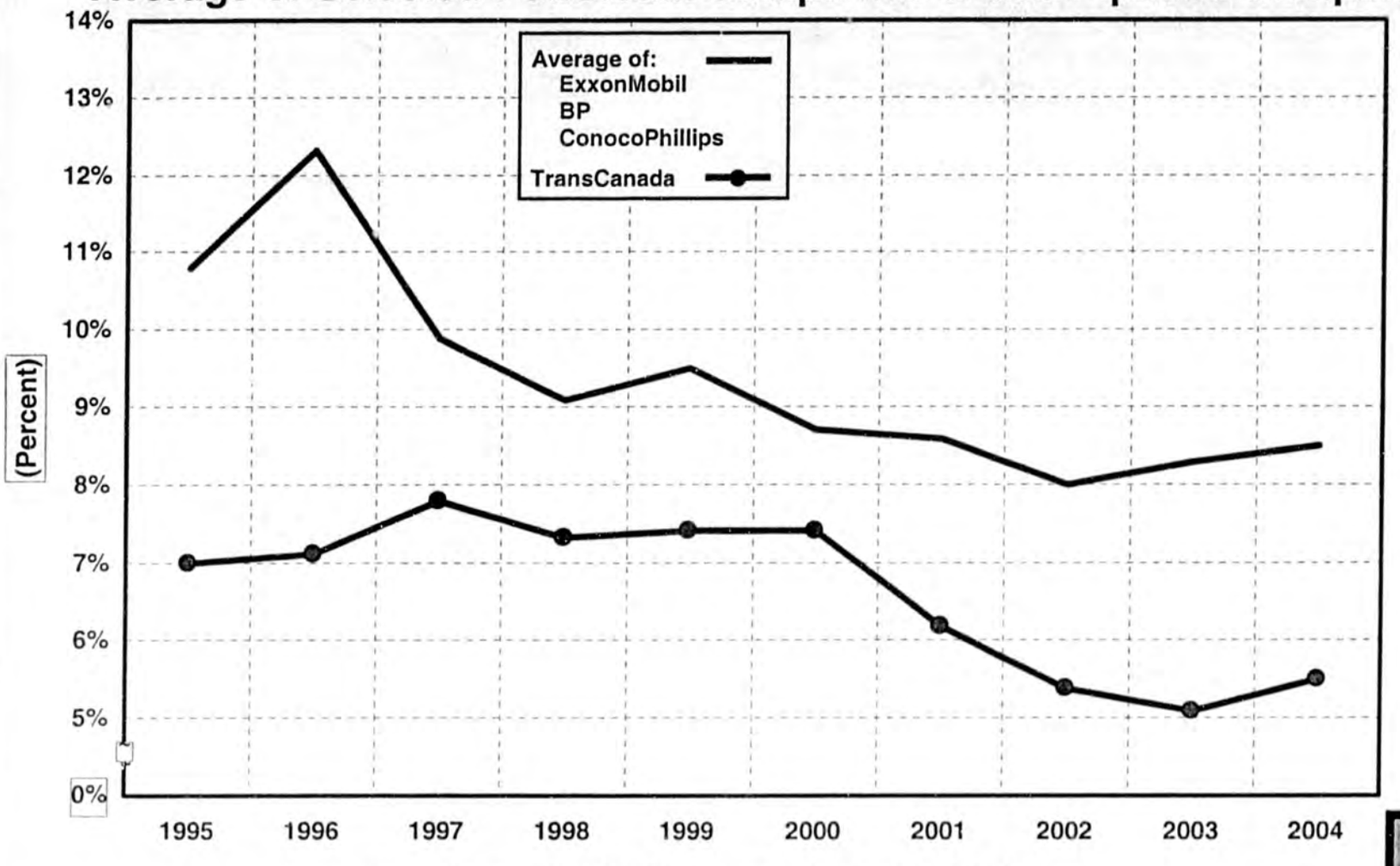
Source: Value Line (March 18, 2005); Ibbotson SBBI Valuation Edition, 2005 Yearbook.

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Weighted Average Cost of Capital

(1995 - 2004)

Average of Selected Petroleum Companies & Gas Pipeline Company

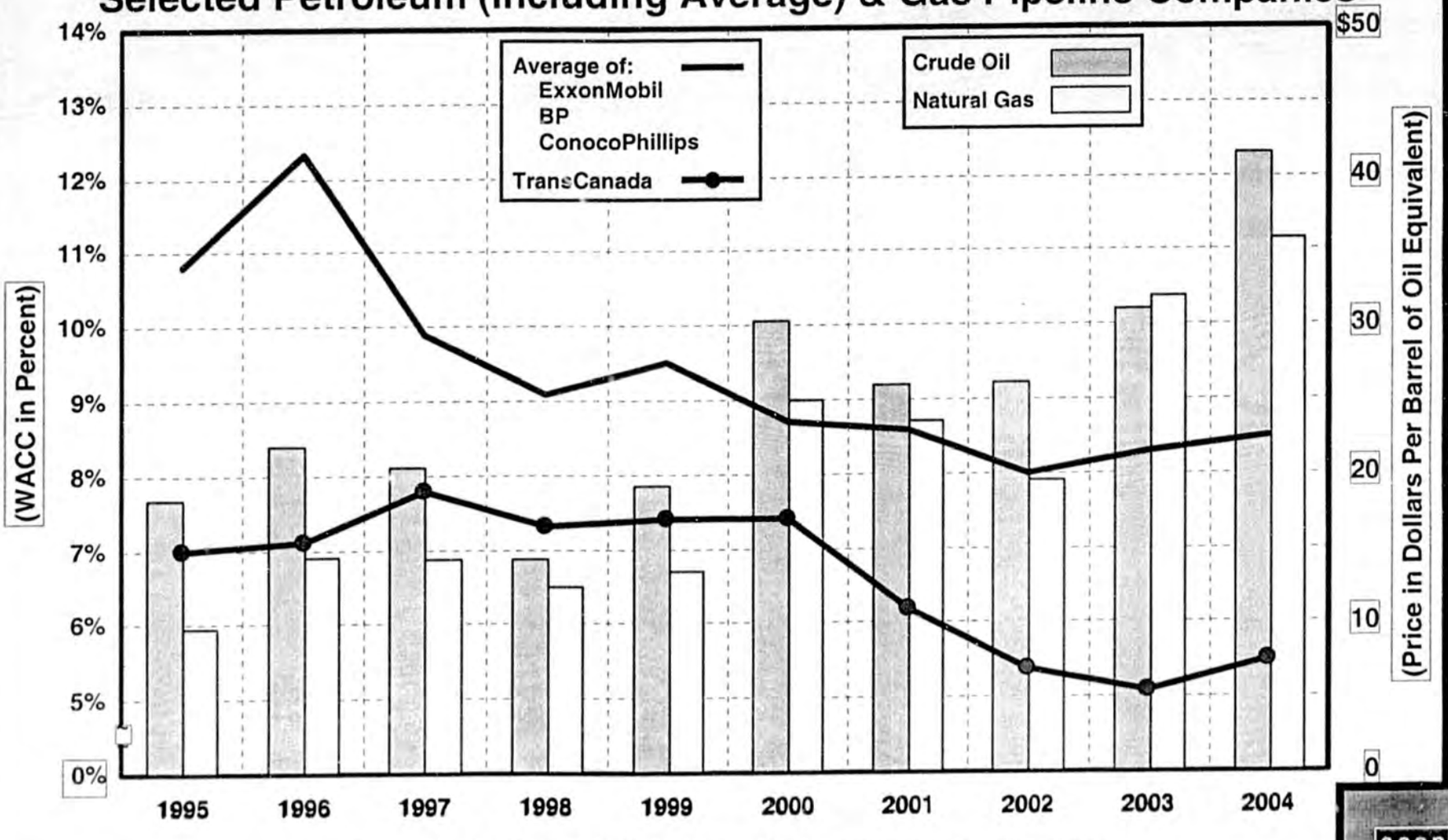


Source: Value Line (March 18, 2005); Ibbotson SBBI Valuation Edition, 2005 Yearbook.

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Weighted Average Cost of Capital
(1995 - 2004)

Selected Petroleum (Including Average) & Gas Pipeline Companies



Source: Value Line (March 18, 2005); Ibbotson SBBI Valuation Edition, 2005 Yearbook; NYMEX.

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Weighted Average Cost of Capital
(1995 - 2004)

	5-Year Average	10-Year Average
	(Percent)	
	(1)	(2)
ExxonMobil	7.9%	9.1%
BP	9.1	9.9
ConocoPhillips	8.3	9.1
Average of Above 3	8.4	9.4
TransCanada	5.9	6.6
NYMEX Crude Oil ($/Bbl.)	$30.96	$24.96
NYMEX Natural Gas ($/MMBtu)	$4.68	$3.46

Source: Calculation of Weighted Average Cost of Capital, for each company; NYMEX

PRESENTATION ON
ALASKA GAS PIPELINE PROJECT

to Alaska State Legislative Budget & Audit Committee
August 31, 2005

Investment Decision-Making by Oil and Gas Companies

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How Oil and Gas Companies Look At Projects

- Does it offer a strategic fit?
- Does it offer diversification?
- Does it create wealth (NPV >0 at market cost of capital)?
- Treat investment and financing as separate decisions
  - Evaluate project as if it were all equity financed
  - But, take account of ability to create value if special financing is available (e.g. federal loan guarantee)

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Financial Criteria

- NPV – Net Present Value
- NPV per BOE (Barrels of Oil Equivalent)
- IRR – Internal Rate of Return
- PI - Profitability Index
- Cash Flow (Undiscounted)

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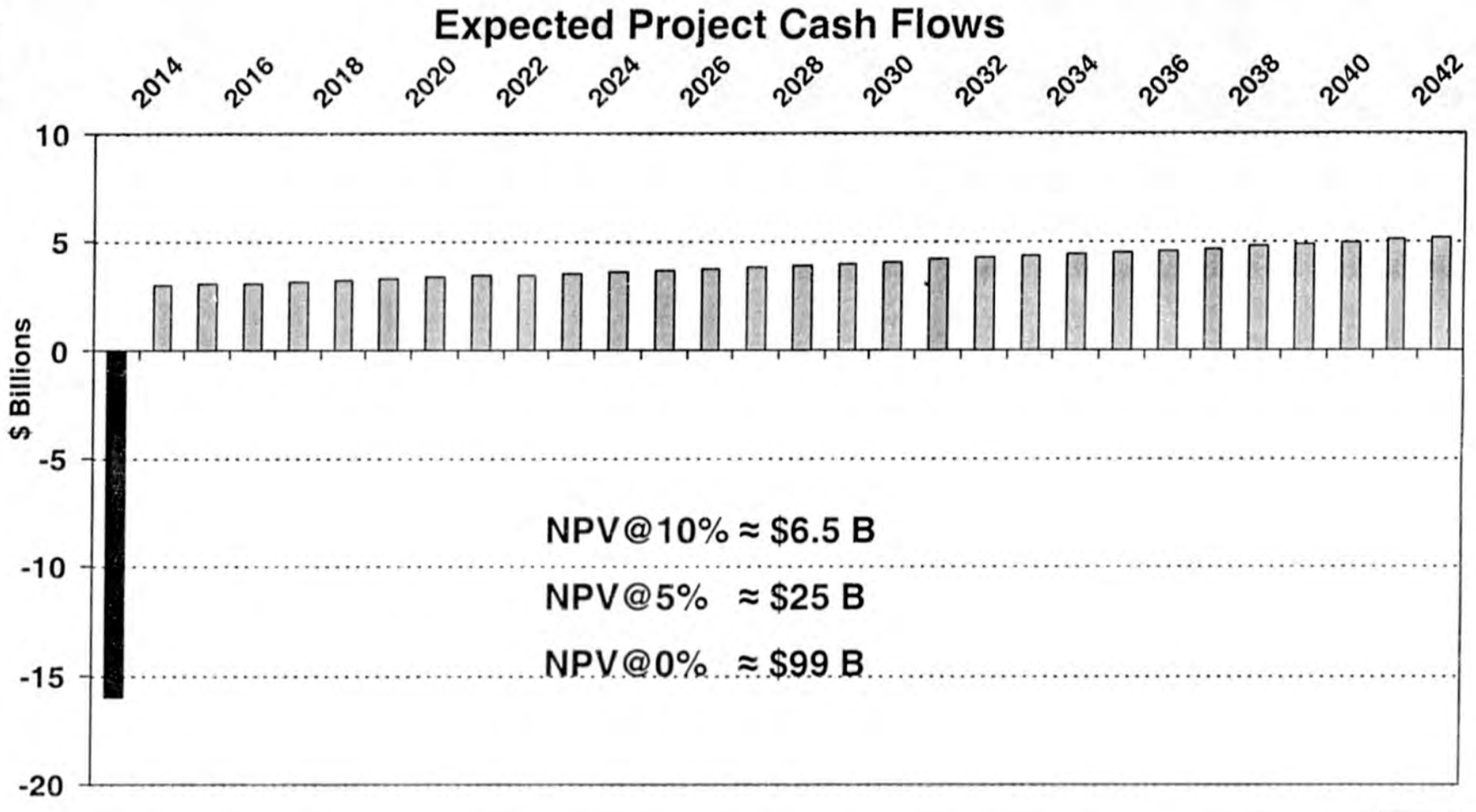
Choice of Discount Rate

- Discount at risk-adjusted of capital, the expected rate of return that can be realized on similar investments with equivalent risk
  - Currently, using 10% for Gasline discount rate
- Projects need to be evaluated at the risk-adjusted cost of capital, which may be above the Weighted Average Cost of Capital
- What makes a project riskier?
  - Uncertainty
  - Political risk
  - Economic risk

Financial Criteria
Net Present Value (NPV)

- Present value of future cash flows including capital investment
- A project with a positive NPV is a candidate for acceptance

Stylized Cash Flow



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Financial Criteria
NPV per BOE

- Measure is highly sensitive to price forecasts
- $1.00/BOE typical of gas projects with large infrastructure costs (e.g. LNG)

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Financial Criteria
Internal Rate of Return (IRR)

- The discount rate at which the NPV of a project equals zero.
- All projects with an IRR greater than the risk-adjusted cost of capital should be accepted when there are no capital budget restraints. Choose higher IRR projects when there are capital budget restraints. Although the "market" would fund projects with IRR above cost of capital, project can be postponed.
- IRR of 12-15% currently indicates threshold rate of return without significant risk factors.
- Energy companies are developing alternative projects in 15%-20% range.

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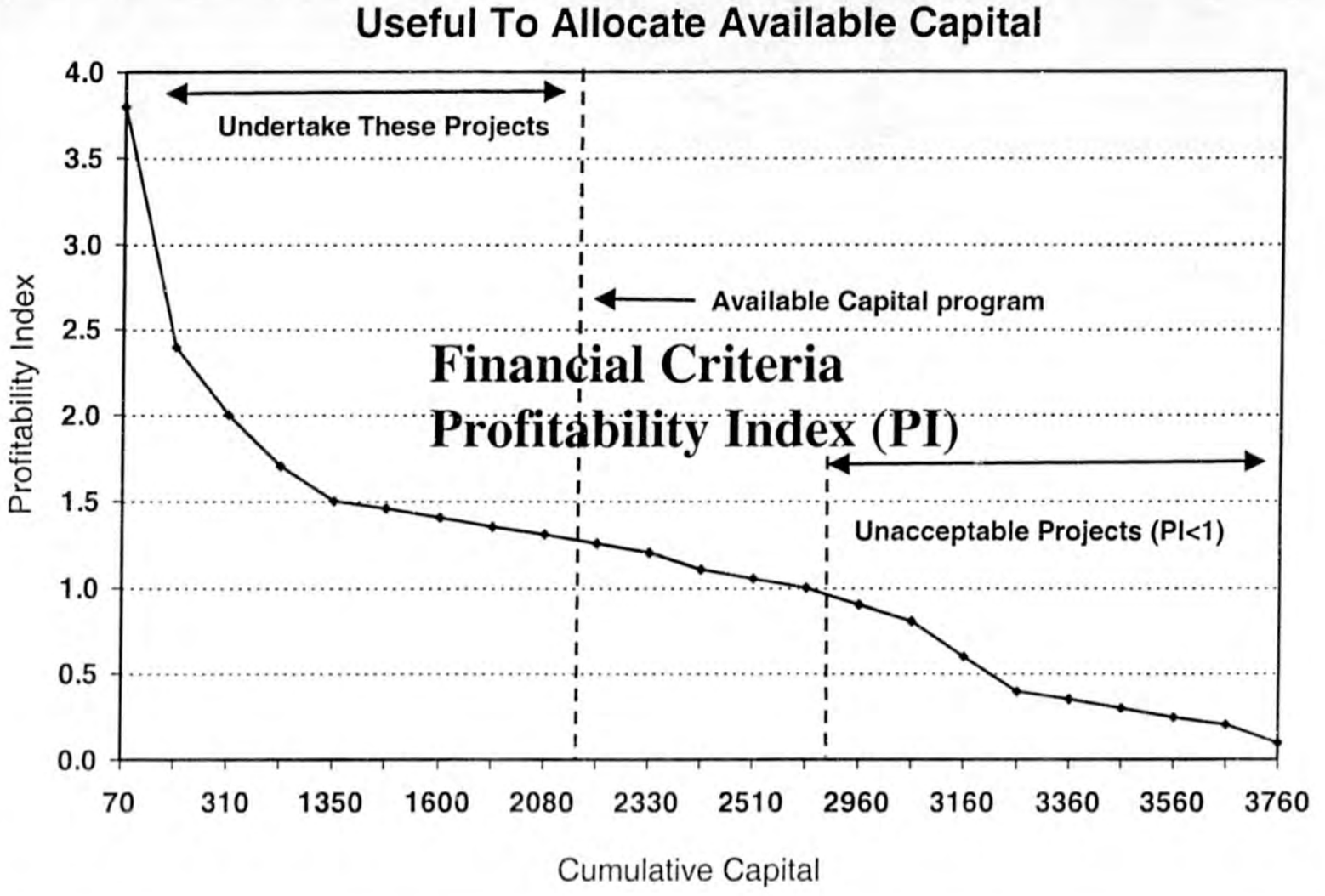
Financial Criteria
Profitability Index (PI)

- PI = [present value of cash inflows/present value of cash outflows] at a given discount rate.
  PI = [NPV+PV(Investment)]/PV(Investment)
- Profitability Index captures the present value per dollar of investment - "biggest bang for the buck."
- PI > 1 for those projects which have a positive NPV.
- Measure is useful to allocate capital if there are capital restraints.
- Array projects from high to low and choose projects with highest PI subject to capital constraint.

- Note: Some analysts use a different definition of the profitability index:
  NPV/I = NPV/PV(Investment)
  PI=NPV/I + 1

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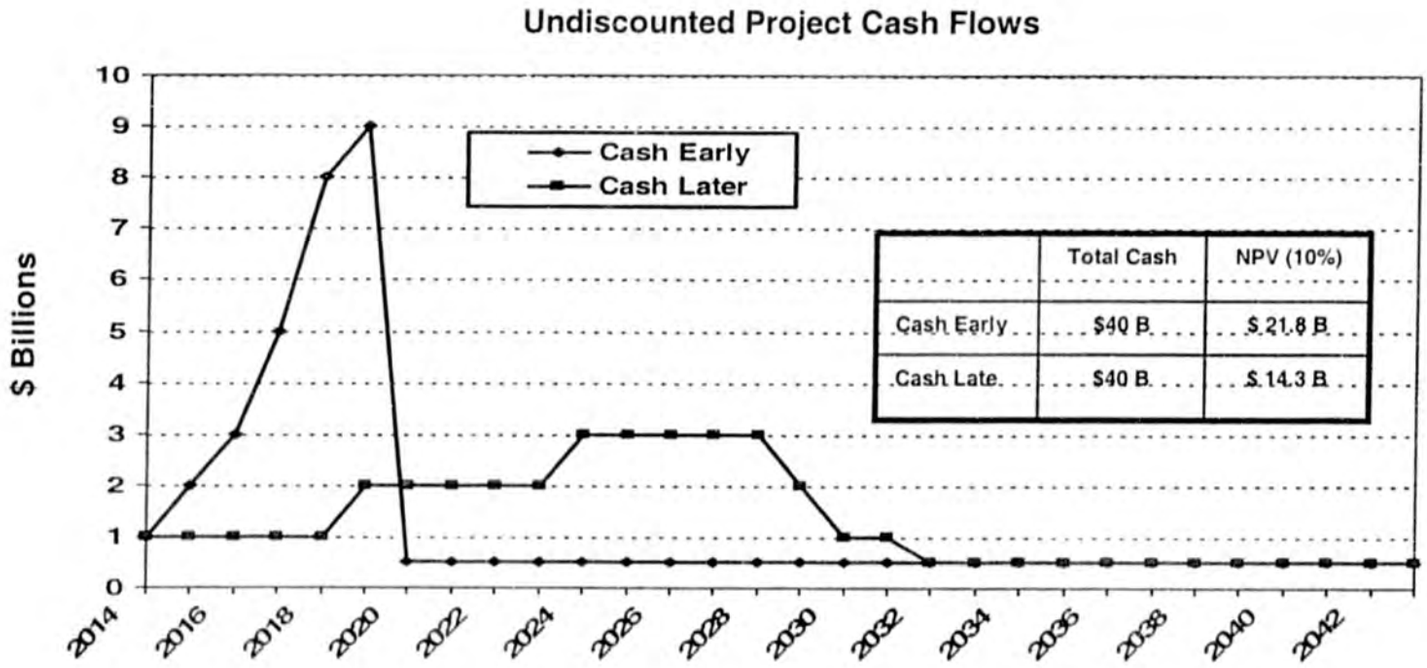
Financial Criteria
Profitability Index (PI)



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Financial Criteria
Cash (Undiscounted)

- Not used as key investment metric
- Often used to view size of project in presentations to sovereign governments
- Antithetical to discounted cash flow analysis
  - Suffers from failure to reward cash early
  - E.g. Cash flows below are equivalent, but not in discounted terms



	Total Cash	NPV (10%)
Cash Early	$40 B	$ 21.8 B
Cash Late	$40 B	$ 14.3 B

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Use of Financial Metrics

- **Comparing Gasline project with other projects in the firm's project portfolio.**
  - **Assuming capital constraints, an oil and gas company would compare alternative independent projects of the same riskiness on the basis of PI (Profitability Index). If an alternative project is riskier, the PI of the riskier project would be discounted at a higher rate to reflect the riskiness of the cash flows.**

- **Comparing a Gasline proposal with another Gasline proposal or with the "Status Quo."**
  - **An oil and gas company would use NPV (Net Present Value).**
    - **Note that the two proposals may not have the same risk. (e.g. fiscal certainty making cash flows less risky)**
    - **As a practical matter, discount rate adjustment may not be considered.**

- **Evaluating the effect of a delay in the Gasline.**
  - **An oil and gas company would use NPV, not IRR (Internal Rate of Return).**
    - **Note: the IRR of a project in which the cash flows are simply delayed will be unchanged.**

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Incorporating Risk in the Discount Rate

- If cash flows are risky, they should be adjusted to account for this risk
- As a practical matter, this is not generally done
- Instead, firms may adjust the discount rate to account for risk
  - Somewhat subjective, but guided by analytical work
  - e.g. Ibbotson work indicated the following international costs of capital, based on market data and country credit ratings
    - US ~ 12%
    - Norway ~13%
    - Qatar ~ 21%
    - Venezuela ~ 25%
  - An oil company comparing projects in the US with those in other countries will increase the discount rate to reflect the divergent risks
  - They will also lower the discount rate if there are less risky cash flows from guaranteed purchasers, fiscal certainty, etc.

Potential Constraints

Producers will not use financial metrics exclusively

Producers will address additional issues in their project evaluation

- Do we have the personnel and skill sets to undertake the project?
- Will Management be able to focus on managing the project?
  - Is the project so complex that it will distract Management's attention from other projects?
  - Does the project size offer economies of scale?
- Is the project discretionary?
- What is the effect of a delay on project economics?
  - Will a delay allow us to undertake other projects in a more timely manner?
    - Do we risk losing the project or a more attractive project if we delay?
  - Do we have contractual obligations that impact timing?
- Does the project offer improved diversification?
  - Business Line
  - Regionally
- Do we have a competitive advantage in this project?

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Producer View of Future Gas Prices

- Producers have been "burned" by their forecasts of high gas prices in the past
  - e.g. Gas Bubble of 1990s
- Producers will test their projects against a price path that is below their "Most Likely" view
  - They use the "official price view" as a speed limit to signal aggressiveness
  - By "high-grading," they will have a suite of projects resilient to price risk
  - Their price view lags the current market price by as much as 5-7 years as prices rise, and by 2 years as prices fall. Current view might be: $24-26 oil (~$4-4.25 gas)
- Producers will also "stress" test their projects
- The consequences of error are not symmetrical
  - If a producer underestimates the future path of prices, they will not undertake high risk projects and their returns will skyrocket (the current situation relative to a few years ago)
  - If a producer overestimates the future path of prices, they will be scorned by Wall Street and investors (their position in the late 1990s)
  - They will "miss" opportunities, but these misses will not be fully "penalized" by the market

Strong Incentives for Conservative Investment Strategy

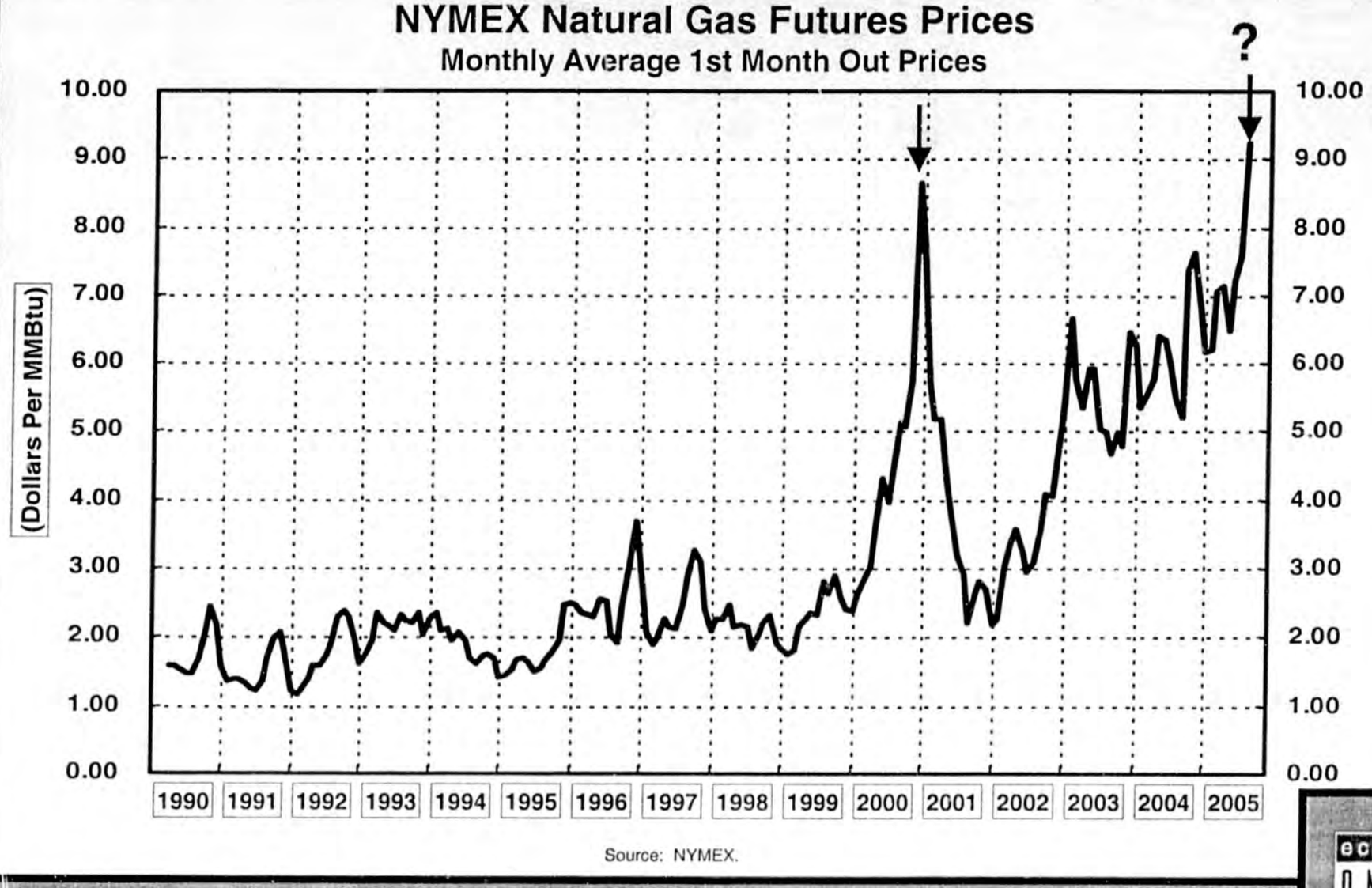
Conservative Investment Strategy Dominates In Capital Restrained World

	Gas Prices High	*Gas Prices Low*
Aggressive Investment Strategy	High ROCE	
Conservative Investment Strategy	Very High ROCE	Moderate ROCE

ROCE = Return on Capital Employed

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Past Natural Gas Bubbles



PRESENTATION ON
ALASKA GAS PIPELINE PROJECT

to Alaska State Legislative Budget & Audit Committee
August 31, 2005

Analysis of Project Viability with Vertical Components

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Analysis of Project Viability with Vertical Components

- Where to Look?
- Transfer Prices
- Capacity Commitments

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Where to Look?

- Regulated pipeline is viable as a standalone investment
- Project integration should only improve economics
- Therefore, look to upstream economics
- If upstream economics are attractive, the gas pipeline is viable

Transfer Prices

- Division of revenue between upstream and midstream should reflect market efficiencies
- Regulations will keep tariffs to cost of service (pipeline return dictated by regulatory allowances)
- Upstream capacity commitments will be necessary

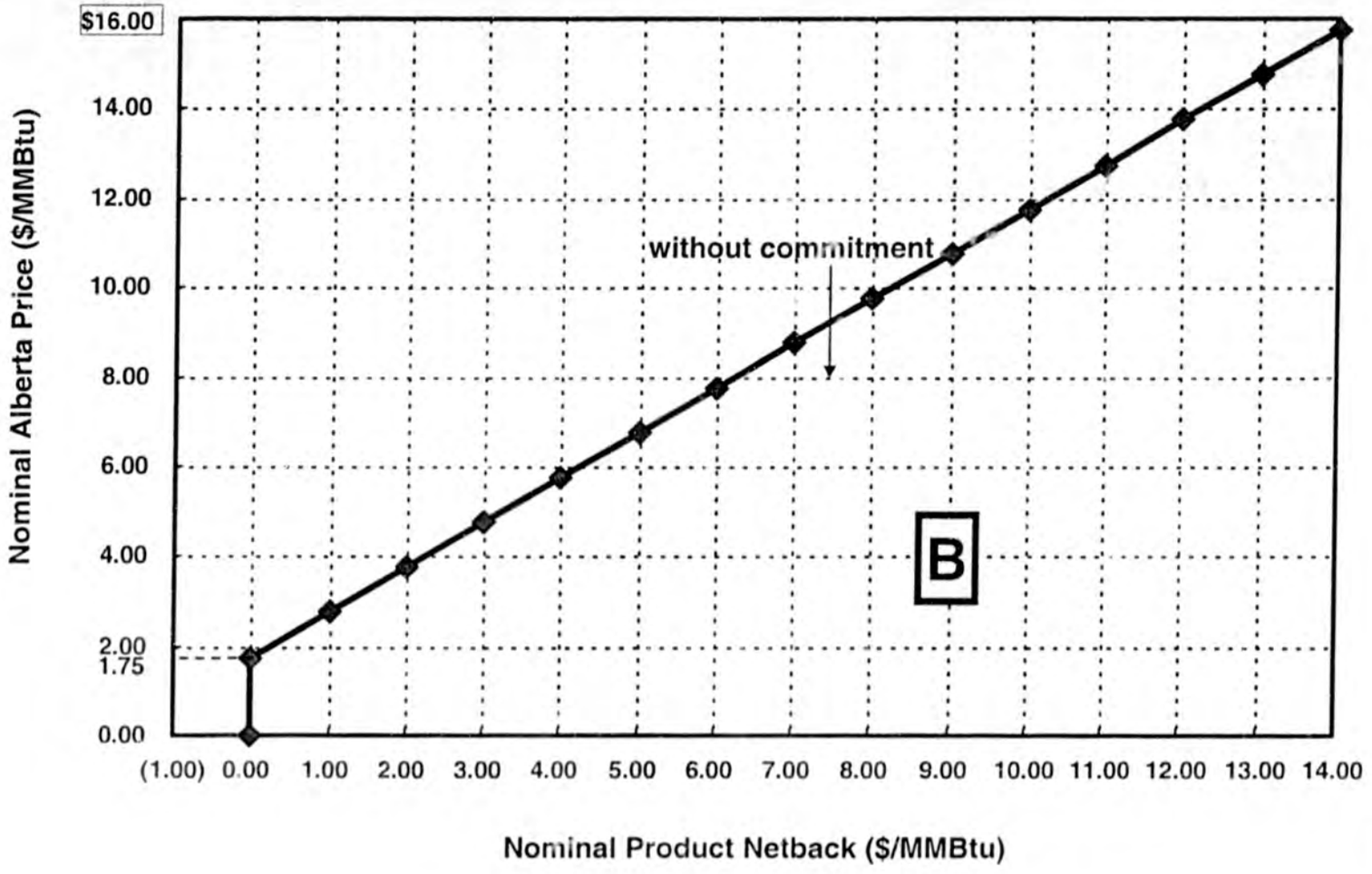
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Economics of Capacity Commitment

- Does not create integrated project
- Not the same as debt; not a consumer of debt capacity
- Changes expected cash flow and risk
- However, these effects are small

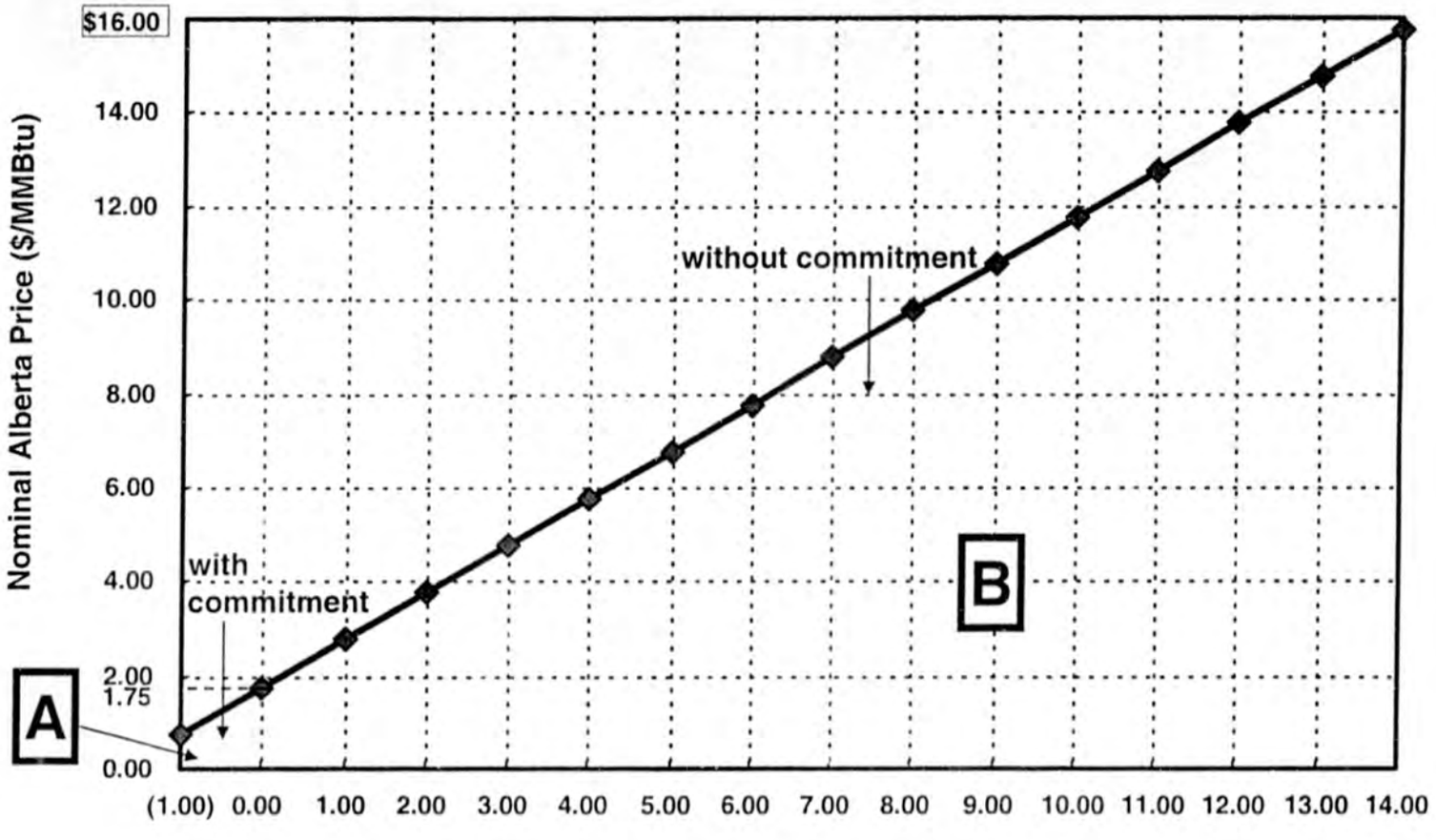
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Gas Prices and Netbacks
(Without Capacity Commitment)



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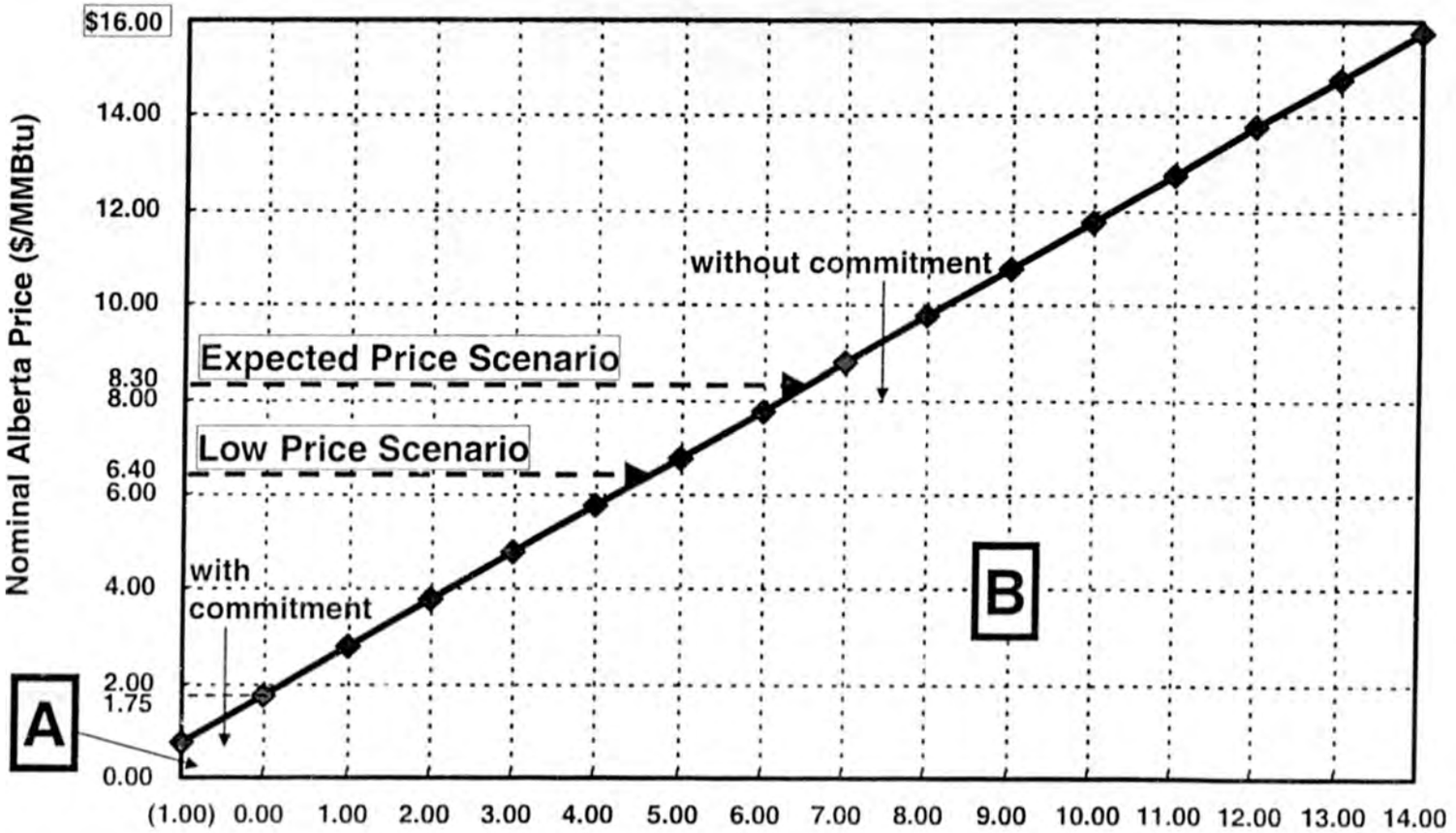
Gas Prices and Netbacks
(with Capacity Commitment)



Note: A is small relative to B.

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Gas Prices and Netbacks
(with Capacity Commitment)



Note: A is small relative to B and is much smaller than the expected market price of gas.

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Avoiding Some Pitfalls

- Integrated project return is less than upstream return; but so is integrated project risk
- Size matters; a lower integrated return may be preferable to a higher return on a smaller standalone investment
- Beware of rate-of-return comparisons across projects with differing risk and investment profiles

PRESENTATION ON
ALASKA GAS PIPELINE PROJECT

to Alaska State Legislative Budget & Audit Committee
August 31, 2005

Net Present Value, Rate of Return, and Profitability Index on Producer Investment

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Estimated Project Returns to Producers

- Development of Model
- Major Assumptions
- Scenarios
- Sensitivities
- Results

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Estimated Project Returns to Producers

Development of Model

- The Administration has developed models of the Gas Pipeline project using a combination of publicly available and confidential data
- Models analyze the economics of the pipeline project from the standpoint of the producers and the State
- At this point, we are not able to discuss the results of those models, their assumptions, or the confidential data they contain

Estimated Project Returns to Producers

Development of Model (cont'd)

- The model reflects:
  - Gas pipeline running from the North Slope, along the Alaska Highway route, with delivery to Alberta
  - Existing fiscal terms (i.e., existing royalty and tax rates)
    - The State and SGDA Applicants have discussed and made proposals that would reflect different terms; we are not able to discuss those at this time
- We examine alternative gas price, cost, and pipeline ownership scenarios

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Estimated Project Returns to Producers

Major Assumptions

- Gas pipeline developed and gas sold under current fiscal terms
- 30-year project, with sale beginning by year-end 2012
- Gas production of 4.5 BCF per day; approximately 50% from Prudhoe Bay, 16% from Point Thomson, and the balance from other fields
- Gas sales of 4.2 BCF per day in Alberta (AECO Hub)
- Gas prices in Alberta average $0.90/MMBtu below Henry Hub/ Chicago levels
- Average heat content of 1.1 MMBtu per MCF
- Gas treatment plant, pipeline, and Point Thomson facilities financed with a combination of 80% debt (with federal guarantees) and 20% equity
- Borrowing costs on federally guaranteed debt of 5% per year
- FERC allows a 14% rate of return on equity for U.S. portion of pipeline; NEB allows a 12% return for Canadian portion

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Estimated Project Returns to Producers

Major Assumptions (cont'd)

- Costs and prices inflated by 2.5% per year from 2004
- Capital costs consistent with producer presentation to legislature in August 2001 and June 2004
  - Capital cost include gas treatment plant, pipeline, and Point Thomson field development costs
  - We have added additional capital for construction of a "feeder" pipeline from Point Thomson to the gas treatment plant and for development of gas reserves outside of Prudhoe Bay and Point Thomson
- We assume gas sold on a "BTU" basis (i.e., no uplift for potential NGL extraction) -- likely a conservative assumption
- Consistent with this assumption, we have not included capital for a NGL extraction facility
- We have not attempted to model any related impact on liquids production at this time

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Estimated Project Returns to Producers

Scenarios

- **Pipeline Ownership**

  1. **Baseline: Producers build and own 100% of pipeline**

  2. **Producers own 50% of pipeline with another party**

  3. **Third-party (such as TransCanada) builds and owns 100% of pipeline**

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Estimated Project Returns to Producers

Sensitivities

- Gas prices
- Costs

Estimated Project Returns to Producers
Sensitivities (cont'd)

- Gas Prices
  - EIA Annual Energy Outlook (AEO) 2005 ($4.90)*
    - Prices (in 2004 dollars) range from $4.05 to $5.10 over time
  - Futures Market Implied ($5.00)*
  - Low Price Scenario ($4.00)*
  - High Price Scenario ($6.00)*

* Constant 2004 dollars.

Estimated Project Returns to Producers

Sensitivities (cont'd)

- Costs
  - Baseline Capital and Operating Costs
  - 20 Percent Increase Relative to Baseline in Capital and Operating Costs
  - 20 Percent Decrease Relative to Baseline in Capital and Operating Costs

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Estimated Project Returns to Producers

Results

Scenario 1:
Producers Own 100% of Pipeline

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Estimated Project Returns to Producers
(Producers Own 100% of Pipeline)

- Producers' capital outlays include cost of all facilities, including gas treatment plant, pipelines, and field development

- Producers ship all gas on pipeline constructed, financed, and regulated as described earlier in "Assumptions" section

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Estimated Project Returns to Producers
(Producers Own 100% of Pipeline)

Price Assumption	NPV[10] ($ Billion) (1)	NPV[10] /BOE ($/Bbl.) (2)	Profitability Index[10] (3)	IRR (Percent) (4)
*EIA AEO 2005 ($4.90)**	*$14.1*	*$1.85*	*2.36*	*19.2%*
Futures Market Implied ($5.00)*	15.5	2.03	2.49	20.4%
Low Price Scenario ($4.00)*	9.8	1.28	1.94	17.2%
High Price Scenario ($6.00)*	21.2	2.77	3.04	23.1%

* Constant 2004 dollars.

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Estimated Project Returns to Producers

(Producers Own 100% of Pipeline – Costs Increased by 20%)

Base Case

Price Assumption	NPV[10] ($ Billion) (1)	NPV[10] /BOE ($/Bbl.) (2)	Profitability Index[10] (3)	IRR (Percent) (4)
*EIA AEO 2005 ($4.90)**	*$14.1*	*$1.85*	*2.36*	*19.2%*
Futures Market Implied ($5.00)*	15.5	2.03	2.49	20.4%
Low Price Scenario ($4.00)*	9.8	1.28	1.94	17.2%
High Price Scenario ($6.00)*	21.2	2.77	3.04	23.1%

Base Case

Costs Increased by 20%

Price Assumption	NPV[10] ($ Billion) (1)	NPV[10] /BOE ($/Bbl.) (2)	Profitability Index[10] (3)	IRR (Percent) (4)
*EIA AEO 2005 ($4.90)**	*$12.6*	*$1.65*	*2.05*	*17.4%*
Futures Market Implied ($5.00)*	14.0	1.83	2.16	18.4%
Low Price Scenario ($4.00)*	8.3	1.09	1.69	15.5%
High Price Scenario ($6.00)*	19.7	2.57	2.63	21.0%

Costs Increased by 20%

* Constant 2004 dollars.

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Estimated Project Returns to Producers

(Producers Own 100% of Pipeline; Costs Decreased by 20%)

Base Case

Price Assumption	NPV[10] ($ Billion) (1)	NPV[10] /BOE ($/Bbl.) (2)	Profitability Index[10] (3)	IRR (Percent) (4)
*EIA AEO 2005 ($4.90)**	*$14.1*	*$1.85*	*2.36*	*19.2%*
Futures Market Implied ($5.00)*	15.5	2.03	2.49	20.4%
Low Price Scenario ($4.00)*	9.8	1.28	1.94	17.2%
High Price Scenario ($6.00)*	21.2	2.77	3.04	23.1%

Base Case

Costs Decreased by 20%

Price Assumption	NPV[10] ($ Billion) (1)	NPV[10] /BOE ($/Bbl.) (2)	Profitability Index[10] (3)	IRR (Percent) (4)
*EIA AEO 2005 ($4.90)**	*$15.6*	*$2.05*	*2.80*	*21.5%*
Futures Market Implied ($5.00)*	17.0	2.22	2.95	22.9%
Low Price Scenario ($4.00)*	11.3	1.48	2.30	19.4%
High Price Scenario ($6.00)*	22.6	2.96	3.61	25.8%

Costs Decreased by 20%

* Constant 2004 dollars.

Estimated Project Returns to Producers

Results

Scenario 2:
Producers Own 50% of Pipeline

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Estimated Project Returns to Producers
(Producers Own 50% of Pipeline)

- Producers' capital outlays includes cost of gas treatment plant, Point Thomson field development, and additional capital for future gas development, plus 50% of pipeline costs

- Producers ship all gas on 50% owned pipeline constructed, financed, and regulated as described earlier in assumptions section

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Estimated Project Returns to Producers
(Producers Own 50% of Pipeline)

Price Assumption	NPV[10] ($ Billion) (1)	NPV[10] /BOE ($/Bbl.) (2)	Profitability Index[10] (3)	IRR (Percent) (4)
*EIA AEO 2005 ($4.90)**	*$15.3*	*$2.01*	*3.21*	*23.4%*
Futures Market Implied ($5.00)*	16.7	2.18	3.40	25.1%
Low Price Scenario ($4.00)*	11.0	1.44	2.58	21.1%
High Price Scenario ($6.00)*	22.4	2.93	4.22	28.5%

* Constant 2004 dollars.

Estimated Project Returns to Producers

(Producers Own 50% of Pipeline – Costs Increased by 20%)

Base Case

Price Assumption	NPV[10] ($ Billion) (1)	NPV[10] /BOE ($/Bbl.) (2)	Profitability Index[10] (3)	IRR (Percent) (4)
*EIA AEO 2005 ($4.90)**	*$15.3*	*$2.01*	*3.21*	*23.4%*
Futures Market Implied ($5.00)*	16.7	2.18	3.40	25.1%
Low Price Scenario ($4.00)*	11.0	1.44	2.58	21.1%
High Price Scenario ($6.00)*	22.4	2.93	4.22	28.5%

Base Case

Costs Increased by 20%

Price Assumption	NPV[10] ($ Billion) (1)	NPV[10] /BOE ($/Bbl.) (2)	Profitability Index[10] (3)	IRR (Percent) (4)
*EIA AEO 2005 ($4.90)**	*$14.1*	*$1.84*	*2.76*	*21.2%*
Futures Market Implied ($5.00)*	15.4	2.02	2.93	22.7%
Low Price Scenario ($4.00)*	9.7	1.28	2.22	18.9%
High Price Scenario ($6.00)*	21.1	2.76	3.64	26.0%

Costs Increased by 20%

* Constant 2004 dollars.

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Estimated Project Returns to Producers

(Producers Own 50% of Pipeline – Costs Decreased by 20%)

Base Case

Price Assumption	NPV[10] ($ Billion) (1)	NPV[10] /BOE ($/Bbl.) (2)	Profitability Index[10] (3)	IRR (Percent) (4)
*EIA AEO 2005 ($4.90)**	*$15.3*	*$2.01*	*3.21*	*23.4%*
Futures Market Implied ($5.00)*	16.7	2.18	3.40	25.1%
Low Price Scenario ($4.00)*	11.0	1.44	2.58	21.1%
High Price Scenario ($6.00)*	22.4	2.93	4.22	28.5%

Base Case

Costs Decreased by 20%

Price Assumption	NPV[10] ($ Billion) (1)	NPV[10] /BOE ($/Bbl.) (2)	Profitability Index[10] (3)	IRR (Percent) (4)
*EIA AEO 2005 ($4.90)**	*$16.6*	*$2.17*	*3.81*	*26.1%*
Futures Market Implied ($5.00)*	17.9	2.35	4.03	28.1%
Low Price Scenario ($4.00)*	12.3	1.60	3.07	23.8%
High Price Scenario ($6.00)*	23.6	3.09	4.99	31.7%

Costs Decreased by 20%

* Constant 2004 dollars.

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Estimated Project Returns to Producers

Results

Scenario 3:
Producers Ship Over Third-Party Owned Pipeline

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Estimated Project Returns to Producers
(Producers Own 0% of Pipeline)

- Producers' capital outlays includes cost of gas treatment plant, Point Thomson field development, and additional capital for future gas development
- Third-party constructs pipeline facilities, including Point Thomson "feeder" line
- Producers ship all gas on Third-Party owned pipeline constructed, financed, and regulated as described earlier in assumptions section

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Estimated Project Returns to Producers
(Producers Own 0% of Pipeline)

Price Assumption	NPV[10] ($ Billion) (1)	NPV[10] /BOE ($/Bbl.) (2)	Profitability Index[10] (3)	IRR (Percent) (4)
*EIA AEO 2005 ($4.90)**	*$16.5*	*$2.17*	*5.70*	*33.8%*
Futures Market Implied ($5.00)*	17.9	2.34	6.08	36.8%
Low Price Scenario ($4.00)*	12.2	1.60	4.47	31.0%
High Price Scenario ($6.00)*	23.6	3.08	7.70	41.6%

* Constant 2004 dollars.

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Estimated Project Returns to Producers

(Producers Own 0% of Pipeline – Costs Increased by 20%)

Base Case

Price Assumption	NPV[10] ($ Billion) (1)	NPV[10] /BOE ($/Bbl.) (2)	Profitability Index[10] (3)	IRR (Percent) (4)
*EIA AEO 2005 ($4.90)**	*$16.5*	*$2.17*	*5.70*	*33.8%*
Futures Market Implied ($5.00)*	17.9	2.34	6.08	36.8%
Low Price Scenario ($4.00)*	12.2	1.60	4.47	31.0%
High Price Scenario ($6.00)*	23.6	3.08	7.70	41.6%

Base Case

Costs Increased by 20%

Price Assumption	NPV[10] ($ Billion) (1)	NPV[10] /BOE ($/Bbl.) (2)	Profitability Index[10] (3)	IRR (Percent) (4)
*EIA AEO 2005 ($4.90)**	*$15.5*	*$2.03*	*4.99*	*31.0%*
Futures Market Implied ($5.00)*	16.9	2.21	5.33	33.9%
Low Price Scenario ($4.00)*	11.2	1.46	3.87	28.1%
High Price Scenario ($6.00)*	22.5	2.95	6.79	38.6%

Costs Increased by 20%

* Constant 2004 dollars.

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Estimated Project Returns to Producers

(Producers Own 0% of Pipeline – Costs Decreased by 20%)

Base Case

Price Assumption	NPV[10] ($ Billion) (1)	NPV[10] /BOE ($/Bbl.) (2)	Profitability Index[10] (3)	IRR (Percent) (4)
*EIA AEO 2005 ($4.90)**	*$16.5*	*$2.17*	*5.70*	*33.8%*
Futures Market Implied ($5.00)*	17.9	2.34	6.08	36.8%
Low Price Scenario ($4.00)*	12.2	1.60	4.47	31.0%
High Price Scenario ($6.00)*	23.6	3.08	7.70	41.6%

Base Case

Costs Decreased by 20%

Price Assumption	NPV[10] ($ Billion) (1)	NPV[10] /BOE ($/Bbl.) (2)	Profitability Index[10] (3)	IRR (Percent) (4)
*EIA AEO 2005 ($4.90)**	*$17.6*	*$2.30*	*6.59*	*37.0%*
Futures Market Implied ($5.00)*	18.9	2.48	7.01	40.2%
Low Price Scenario ($4.00)*	13.2	1.73	5.21	34.3%
High Price Scenario ($6.00)*	24.6	3.22	8.82	45.1%

Costs Decreased by 20%

* Constant 2004 dollars.

The Impact of Leverage on Project Economics

- Returns shown in prior sections do not account for beneficial effect of "leverage" on producer equity investments -- they reflect average return over entire capital base, both debt and equity
- This project, consistent with pipeline projects generally, will be heavily leveraged
- Leverage under this project is likely to be even greater and more beneficial due to federal loan guarantees of up to 80% of project costs

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The Impact of Leverage on Project Economics
(Producers Own 100% of Pipeline)

Base Case (Debt + Equity)

Price Assumption	NPV[10] ($ Billion) (1)	IRR (Percent) (2)
*EIA AEO 2005 ($4.90)**	*$14.1*	*19.2%*
Futures Market Implied ($5.00)*	15.5	20.4%
Low Price Scenario ($4.00)*	9.8	17.2%
High Price Scenario ($6.00)*	21.2	23.1%

Base Case (Debt + Equity)

Leveraged (Equity Capital Only)

Price Assumption	NPV[10] ($ Billion) (1)	IRR (Percent) (2)
*EIA AEO 2005 ($4.90)**	*$18.5*	*42.9%*
Futures Market Implied ($5.00)*	19.8	46.4%
Low Price Scenario ($4.00)*	14.1	40.3%
High Price Scenario ($6.00)*	25.5	51.5%

Leveraged (Equity Capital Only)

* Constant 2004 dollars.

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The Impact of Leverage on Project Economics (Producers Own 50% of Pipeline)

Base Case (Debt + Equity)

Price Assumption	NPV[10] ($ Billion) (1)	IRR (Percent) (2)
*EIA AEO 2005 ($4.90)**	*$15.3*	*23.4%*
Futures Market Implied ($5.00)*	16.7	25.1%
Low Price Scenario ($4.00)*	11.0	21.1%
High Price Scenario ($6.00)*	22.4	28.5%

Base Case (Debt + Equity)

Leveraged (Equity Capital Only)

Price Assumption	NPV[10] ($ Billion) (1)	IRR (Percent) (2)
*EIA AEO 2005 ($4.90)**	*$18.1*	*50.9%*
Futures Market Implied ($5.00)*	19.5	55.3%
Low Price Scenario ($4.00)*	13.8	48.0%
High Price Scenario ($6.00)*	25.2	61.2%

Leveraged (Equity Capital Only)

* Constant 2004 dollars.

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The Impact of Leverage on Project Economics (Producers Own 0% of Pipeline)

Base Case (Debt + Equity)

Price Assumption	NPV[10] ($ Billion) (1)	IRR (Percent) (2)
*EIA AEO 2005 ($4.90)**	*$16.5*	*33.8%*
Futures Market Implied ($5.00)*	17.9	36.8%
Low Price Scenario ($4.00)*	12.2	31.0%
High Price Scenario ($6.00)*	23.6	41.6%

Base Case (Debt + Equity)

Leveraged (Equity Capital Only)

Price Assumption	NPV[10] ($ Billion) (1)	IRR (Percent) (2)
*EIA AEO 2005 ($4.90)**	*$17.8*	*70.0%*
Futures Market Implied ($5.00)*	19.1	76.1%
Low Price Scenario ($4.00)*	13.5	66.7%
High Price Scenario ($6.00)*	24.8	83.5%

Leveraged (Equity Capital Only)

* Constant 2004 dollars.

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PRESENTATION ON ALASKA GAS PIPELINE PROJECT

to Alaska State Legislative Budget & Audit Committee
August 31, 2005

Impact on State and Municipal Economics From Delay in Gas Pipeline's In-Service Date

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Estimated Impact on State of Alaska and Municipalities of Project Delay Beyond Year-End 2012

- Delay in revenues to State of Alaska and Municipalities
- Reduction in Net Present Value of revenues to State of Alaska and Municipalities

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Estimated Impact on State of Alaska and Municipalities of Project Delay Beyond Year-End 2012

Estimated Delay in Total Revenue in Billion Dollars

Price Assumption	Start Date -- Year Ending: 2013	2014	2015	2016	2017	2018
	(Billion Dollars)					
	(1)	(2)	(3)	(4)	(5)	(6)
*EIA AEO 2005 ($4.90)**	*$1.4*	*$2.9*	*$4.5*	*$6.2*	*$7.9*	*$9.8*
Futures Market Implied ($5.00)*	1.8	3.6	5.6	7.6	9.6	11.8
Low Price Scenario ($4.00)*	1.3	2.6	4.0	5.5	7.0	8.5
High Price Scenario ($6.00)*	2.3	4.7	7.1	9.7	12.3	15.0

* Constant 2004 dollars.

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Estimated Impact on State of Alaska and Municipalities of Project Delay Beyond Year-End 2012

Reduction in Net Present Value (NPV[10])

Price Assumption	Start Date -- Year Ending: 2013	2014	2015	2016	2017	2018
	(Billion Dollars)					
	(1)	(2)	(3)	(4)	(5)	(6)
*EIA AEO 2005 ($4.90)**	*($0.5)*	*($0.9)*	*($1.4)*	*($1.8)*	*($2.2)*	*($2.7)*
Futures Market Implied ($5.00)*	(0.6)	(1.2)	(1.8)	(2.3)	(2.9)	(3.4)
Low Price Scenario ($4.00)*	(0.5)	(0.9)	(1.3)	(1.7)	(2.1)	(2.4)
High Price Scenario ($6.00)*	(0.8)	(1.6)	(2.3)	(3.0)	(3.7)	(4.3)

* Constant 2004 dollars.

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Estimated Impact on State of Alaska and Municipalities of Project Delay Beyond Year-End 2012

Absolute Reduction in Net Present Value (NPV[10])

Price Assumption	Start Date -- Year Ending: 2013	2014	2015	2016	2017	2018
	(Billion Dollars)					
	(1)	(2)	(3)	(4)	(5)	(6)
*EIA AEO 2005 ($4.90)**	*($0.5)*	*($0.9)*	*($1.4)*	*($1.8)*	*($2.2)*	*($2.7)*
Futures Market Implied ($5.00)*	(0.6)	(1.2)	(1.8)	(2.3)	(2.9)	(3.4)
Low Price Scenario ($4.00)*	(0.5)	(0.9)	(1.3)	(1.7)	(2.1)	(2.4)
High Price Scenario ($6.00)*	(0.8)	(1.6)	(2.3)	(3.0)	(3.7)	(4.3)

Percentage Reduction in Net Present Value (NPV[10])

Price Assumption	Start Date -- Year Ending: 2013	2014	2015	2016	2017	2018
	(Percent)					
	(1)	(2)	(3)	(4)	(5)	(6)
*EIA AEO 2005 ($4.90)**	*-4.7%*	*-9.2%*	*-13.9%*	*-18.3%*	*-22.5%*	*-26.6%*
Futures Market Implied ($5.00)*	-6.1%	-11.6%	-17.0%	-22.1%	-27.0%	-31.6%
Low Price Scenario ($4.00)*	-5.8%	-11.1%	-16.2%	-21.2%	-26.0%	-30.5%
High Price Scenario ($6.00)*	-6.2%	-12.0%	-17.4%	-22.6%	-27.5%	-32.2%

* Constant 2004 dollars.

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Estimated Impact on State of Alaska and Municipalities of Project Delay Beyond Year-End 2012

Reduction in Net Present Value (NPV[5])

Price Assumption	Start Date -- Year Ending: 2013	2014	2015	2016	2017	2018
	(Billion Dollars)					
	(1)	(2)	(3)	(4)	(5)	(6)
*EIA AEO 2005 ($4.90)**	*($0.2)*	*($0.3)*	*($0.6)*	*($0.8)*	*($1.1)*	*($1.4)*
Futures Market Implied ($5.00)*	(0.5)	(0.9)	(1.3)	(1.7)	(2.2)	(2.7)
Low Price Scenario ($4.00)*	(0.3)	(0.5)	(0.8)	(1.1)	(1.5)	(1.8)
High Price Scenario ($6.00)*	(0.6)	(1.2)	(1.8)	(2.4)	(3.0)	(3.6)

* Constant 2004 dollars.

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Estimated Impact on State of Alaska and Municipalities of Project Delay Beyond Year-End 2012

Absolute Reduction in Net Present Value (NPV[5])

Price Assumption	Start Date -- Year Ending: 2013	2014	2015	2016	2017	2018
	(Billion Dollars)					
	(1)	(2)	(3)	(4)	(5)	(6)
*EIA AEO 2005 ($4.90)**	*($0.2)*	*($0.3)*	*($0.6)*	*($0.8)*	*($1.1)*	*($1.4)*
Futures Market Implied ($5.00)*	(0.5)	(0.9)	(1.3)	(1.7)	(2.2)	(2.7)
Low Price Scenario ($4.00)*	(0.3)	(0.5)	(0.8)	(1.1)	(1.5)	(1.8)
High Price Scenario ($6.00)*	(0.6)	(1.2)	(1.8)	(2.4)	(3.0)	(3.6)

Percentage Reduction in Net Present Value (NPV[5])

Price Assumption	Start Date -- Year Ending: 2013	2014	2015	2016	2017	2018
	(Percent)					
	(1)	(2)	(3)	(4)	(5)	(6)
*EIA AEO 2005 ($4.90)**	*-0.6%*	*-1.3%*	*-2.3%*	*-3.3%*	*-4.3%*	*-5.5%*
Futures Market Implied ($5.00)*	-1.7%	-3.2%	-4.8%	-6.5%	-8.3%	-10.0%
Low Price Scenario ($4.00)*	-1.5%	-2.7%	-4.1%	-5.6%	-7.2%	-8.8%
High Price Scenario ($6.00)*	-1.8%	-3.5%	-5.2%	-7.0%	-8.9%	-10.7%

* Constant 2004 dollars.

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PRESENTATION ON
ALASKA GAS PIPELINE PROJECT

to Alaska State Legislative Budget & Audit Committee
August 31, 2005

Impact on Net Present Value, Rate of Return, and Profitability Index from Increase in Gas Production Severance Tax

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Estimated Impact of Increase in Gas Production Taxes on Project Returns

- Current gas severance tax rate is 10%
- Examine increases by 10%, 25%, and 50% after 5, 10, 15, 20, and 25 years

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Estimated Impact of Increase in Gas Production Taxes on Project Returns

10% Increase in Rates

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Estimated Impact of 10% Increase in Gas Production Taxes on Project Returns

(Assuming EIA AEO 2005 Pricing of $4.90*)

Tax Increase After:	Amount of Change Due to Tax Increase						
	NPV[10]		NPV[10]/BOE		Profitability Index[10]		IRR
	Absolute	% Change	Absolute	% Change	Absolute	% Change	Absolute
	($ Billion)	(Percent)	($/Bbl.)	(Percent)		(Percent)	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
5 Years	($0.1)	-0.8%	($0.02)	-0.8%	(0.01)	-0.5%	0.0%
10 Years	(0.1)	-0.6%	(0.01)	-0.6%	(0.01)	-0.3%	0.0%
15 Years	(0.0)	-0.3%	(0.01)	-0.3%	(0.00)	-0.2%	0.0%
20 Years	(0.0)	-0.2%	(0.00)	-0.2%	(0.00)	-0.1%	0.0%
25 Years	(0.0)	-0.1%	(0.00)	-0.1%	(0.00)	-0.1%	0.0%

* Constant 2004 dollars.

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Estimated Impact of 10% Increase in Gas Production Taxes on Project Returns

(Assuming Low Price Scenario of $4.00*)

Tax Increase After:	Amount of Change Due to Tax Increase						
	NPV[10]		NPV[10]/BOE		Profitability Index[10]		IRR
	Absolute ($ Billion)	% Change (Percent)	Absolute ($/Bbl.)	% Change (Percent)	Absolute	% Change (Percent)	Absolute (Percent)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
5 Years	($0.0)	-0.9%	($0.01)	-0.9%	(0.01)	-0.4%	0.0%
10 Years	(0.0)	-0.6%	(0.01)	-0.6%	(0.01)	-0.3%	0.0%
15 Years	(0.0)	-0.3%	(0.00)	-0.3%	(0.00)	-0.2%	0.0%
20 Years	(0.0)	-0.2%	(0.00)	-0.2%	(0.00)	-0.1%	0.0%
25 Years	(0.0)	-0.1%	(0.00)	-0.1%	(0.00)	0.0%	0.0%

* Constant 2004 dollars.

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Estimated Impact of 10% Increase in Gas Production Taxes on Project Returns

(Assuming High Price Scenario of $6.00*)

Tax Increase After:	Amount of Change Due to Tax Increase						
	NPV[10]		NPV[10]/BOE		Profitability Index[10]		IRR
	Absolute	% Change	Absolute	% Change	Absolute	% Change	Absolute
	($ Billion)	(Percent)	($/Bbl.)	(Percent)		(Percent)	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
5 Years	($0.1)	-0.7%	($0.02)	-0.7%	(0.01)	-0.5%	0.0%
10 Years	(0.1)	-0.5%	(0.01)	-0.5%	(0.01)	-0.3%	0.0%
15 Years	(0.1)	-0.3%	(0.01)	-0.3%	(0.01)	-0.2%	0.0%
20 Years	(0.0)	-0.1%	(0.00)	-0.1%	(0.00)	-0.1%	0.0%
25 Years	(0.0)	-0.1%	(0.00)	-0.1%	(0.00)	0.0%	0.0%

* Constant 2004 dollars.

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Estimated Impact of Increase in Gas Production Taxes on Project Returns

25% Increase in Rates

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Estimated Impact of 25% Increase in Gas Production Taxes on Project Returns

(Assuming EIA AEO 2005 Pricing of $4.90*)

Tax Increase After:	Amount of Change Due to Tax Increase						
	NPV[10]		NPV[10]/BOE		Profitability Index[10]		IRR
	Absolute	% Change	Absolute	% Change	Absolute	% Change	Absolute
	($ Billion)	(Percent)	($/Bbl.)	(Percent)		(Percent)	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
5 Years	($0.3)	-2.0%	($0.04)	-2.0%	(0.03)	-1.2%	-0.1%
10 Years	(0.2)	-1.4%	(0.03)	-1.4%	(0.02)	-0.8%	-0.1%
15 Years	(0.1)	-0.8%	(0.02)	-0.8%	(0.01)	-0.5%	0.0%
20 Years	(0.1)	-0.5%	(0.01)	-0.5%	(0.01)	-0.3%	0.0%
25 Years	(0.0)	-0.2%	(0.00)	-0.2%	(0.00)	-0.1%	0.0%

* Constant 2004 dollars.

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Estimated Impact of 25% Increase in Gas Production Taxes on Project Returns

(Assuming Low Price Scenario of $4.00*)

Tax Increase After:	Amount of Change Due to Tax Increase						
	NPV[10]		NPV[10]/BOE		Profitability Index[10]		IRR
	Absolute	% Change	Absolute	% Change	Absolute	% Change	Absolute
	($ Billion)	(Percent)	($/Bbl.)	(Percent)		(Percent)	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
5 Years	($0.2)	-2.1%	($0.03)	-2.1%	(0.02)	-1.0%	-0.1%
10 Years	(0.1)	-1.4%	(0.02)	-1.4%	(0.01)	-0.7%	0.0%
15 Years	(0.1)	-0.9%	(0.01)	-0.9%	(0.01)	-0.4%	0.0%
20 Years	(0.0)	-0.5%	(0.01)	-0.5%	(0.00)	-0.2%	0.0%
25 Years	(0.0)	-0.2%	(0.00)	-0.2%	(0.00)	-0.1%	0.0%

* Constant 2004 dollars.

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Estimated Impact of 25% Increase in Gas Production Taxes on Project Returns

(Assuming High Price Scenario of $6.00)*

Tax Increase After:	Amount of Change Due to Tax Increase						
	NPV[10]		NPV[10]/BOE		Profitability Index[10]		IRR
	Absolute	% Change	Absolute	% Change	Absolute	% Change	Absolute
	($ Billion)	(Percent)	($/Bbl.)	(Percent)		(Percent)	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
5 Years	($0.4)	-1.8%	($0.05)	-1.8%	(0.04)	-1.2%	-0.1%
10 Years	(0.2)	-1.1%	(0.03)	-1.1%	(0.02)	-0.8%	0.0%
15 Years	(0.1)	-0.7%	(0.02)	-0.7%	(0.01)	-0.5%	0.0%
20 Years	(0.1)	-0.4%	(0.01)	-0.4%	(0.01)	-0.2%	0.0%
25 Years	(0.0)	-0.2%	(0.00)	-0.2%	(0.00)	-0.1%	0.0%

* Constant 2004 dollars.

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Estimated Impact of Increase in Gas Production Taxes on Project Returns

50% Increase in Rates

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Estimated Impact of 50% Increase in Gas Production Taxes on Project Returns

(Assuming EIA AEO 2005 Pricing of $4.90*)

Tax Increase After:	Amount of Change Due to Tax Increase						
	NPV[10]		NPV[10]/BOE		Profitability Index[10]		IRR
	Absolute	% Change	Absolute	% Change	Absolute	% Change	Absolute
	($ Billion)	(Percent)	($/Bbl.)	(Percent)		(Percent)	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
5 Years	($0.6)	-4.1%	($0.08)	-4.1%	(0.06)	-2.4%	-0.2%
10 Years	(0.4)	-2.8%	(0.05)	-2.8%	(0.04)	-1.6%	-0.1%
15 Years	(0.2)	-1.7%	(0.03)	-1.7%	(0.02)	-1.0%	0.0%
20 Years	(0.1)	-0.9%	(0.02)	-0.9%	(0.01)	-0.5%	0.0%
25 Years	(0.1)	-0.4%	(0.01)	-0.4%	(0.01)	-0.2%	0.0%

* Constant 2004 dollars.

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Estimated Impact of 50% Increase in Gas Production Taxes on Project Returns

(Assuming Low Price Scenario of $4.00*)

Tax Increase After:	Amount of Change Due to Tax Increase						
	NPV[10]		NPV[10]/BOE		Profitability Index[10]		IRR
	Absolute	% Change	Absolute	% Change	Absolute	% Change	Absolute
	($ Billion)	(Percent)	($/Bbl.)	(Percent)		(Percent)	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
5 Years	($0.4)	-4.3%	($0.06)	-4.3%	(0.04)	-2.1%	-0.2%
10 Years	(0.3)	-2.9%	(0.04)	-2.9%	(0.03)	-1.4%	-0.1%
15 Years	(0.2)	-1.7%	(0.02)	-1.7%	(0.02)	-0.8%	0.0%
20 Years	(0.1)	-1.0%	(0.01)	-1.0%	(0.01)	-0.5%	0.0%
25 Years	(0.0)	-0.4%	(0.01)	-0.4%	(0.00)	-0.2%	0.0%

* Constant 2004 dollars.

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Estimated Impact of 50% Increase in Gas Production Taxes on Project Returns

(Assuming High Price Scenario of $6.00*)

Tax Increase After:	Amount of Change Due to Tax Increase						
	NPV[10]		NPV[10]/BOE		Profitability Index[10]		IRR
	Absolute	% Change	Absolute	% Change	Absolute	% Change	Absolute
	($ Billion)	(Percent)	($/Bbl.)	(Percent)		(Percent)	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
5 Years	($0.7)	-3.5%	($0.10)	-3.5%	(0.07)	-2.4%	-0.2%
10 Years	(0.5)	-2.3%	(0.06)	-2.3%	(0.05)	-1.5%	-0.1%
15 Years	(0.3)	-1.4%	(0.04)	-1.4%	(0.03)	-0.9%	0.0%
20 Years	(0.2)	-0.7%	(0.02)	-0.7%	(0.02)	-0.5%	0.0%
25 Years	(0.1)	-0.3%	(0.01)	-0.3%	(0.01)	-0.2%	0.0%

* Constant 2004 dollars.

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