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

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

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

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

Guarantees

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

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

for minutes
5/4/07

Alaska Gasline
PORT AUTHORITY

House Finance Committee

May 3, 2007

AGPA Project Description

Alaska Gasline Port Authority

Gas Conditioning Plant in Prudhoe Bay

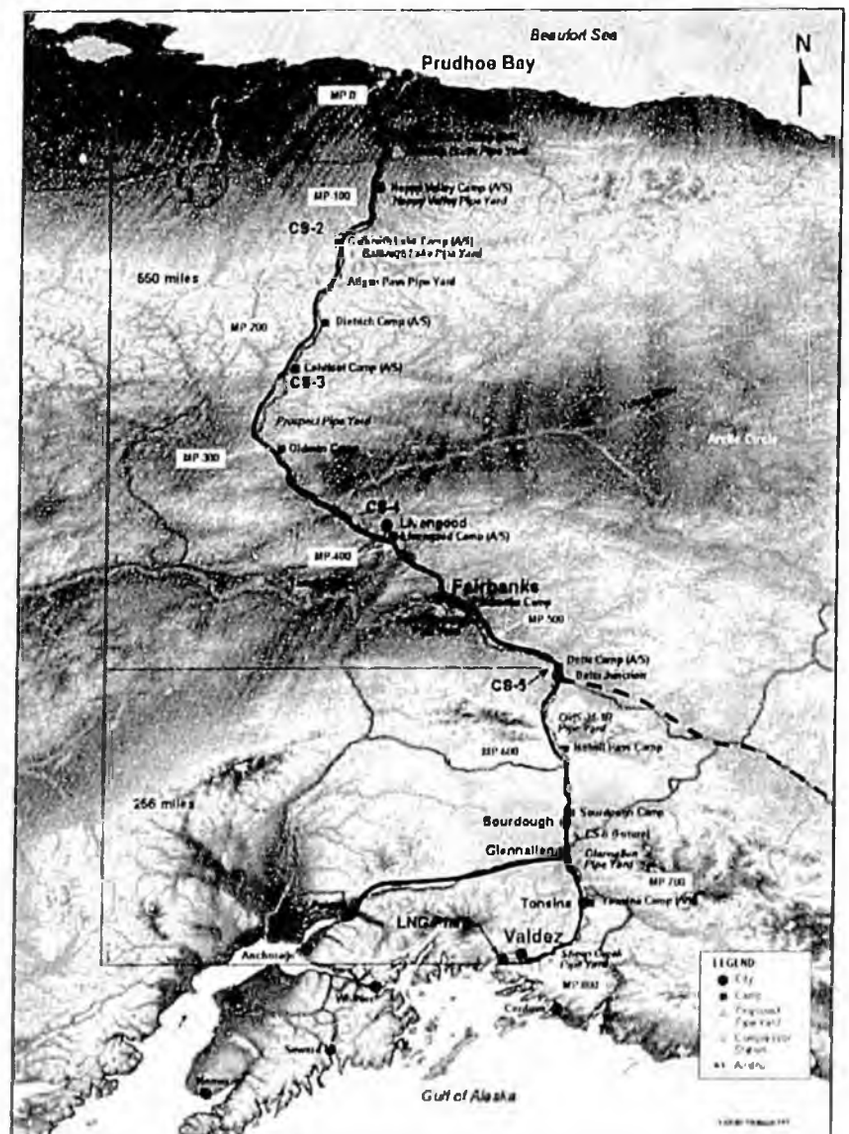
- removes impurities
- compresses and chills the gas to pipeline specifications

Pipeline from Prudhoe Bay to Valdez

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

LNG Facility in Valdez

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



Phased Project = Better Cost Overrun Risk Management

Alaska Gasline Port Authority

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

Project Status

Alaska Gasline Port Authority

1. Project Route Permitted

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

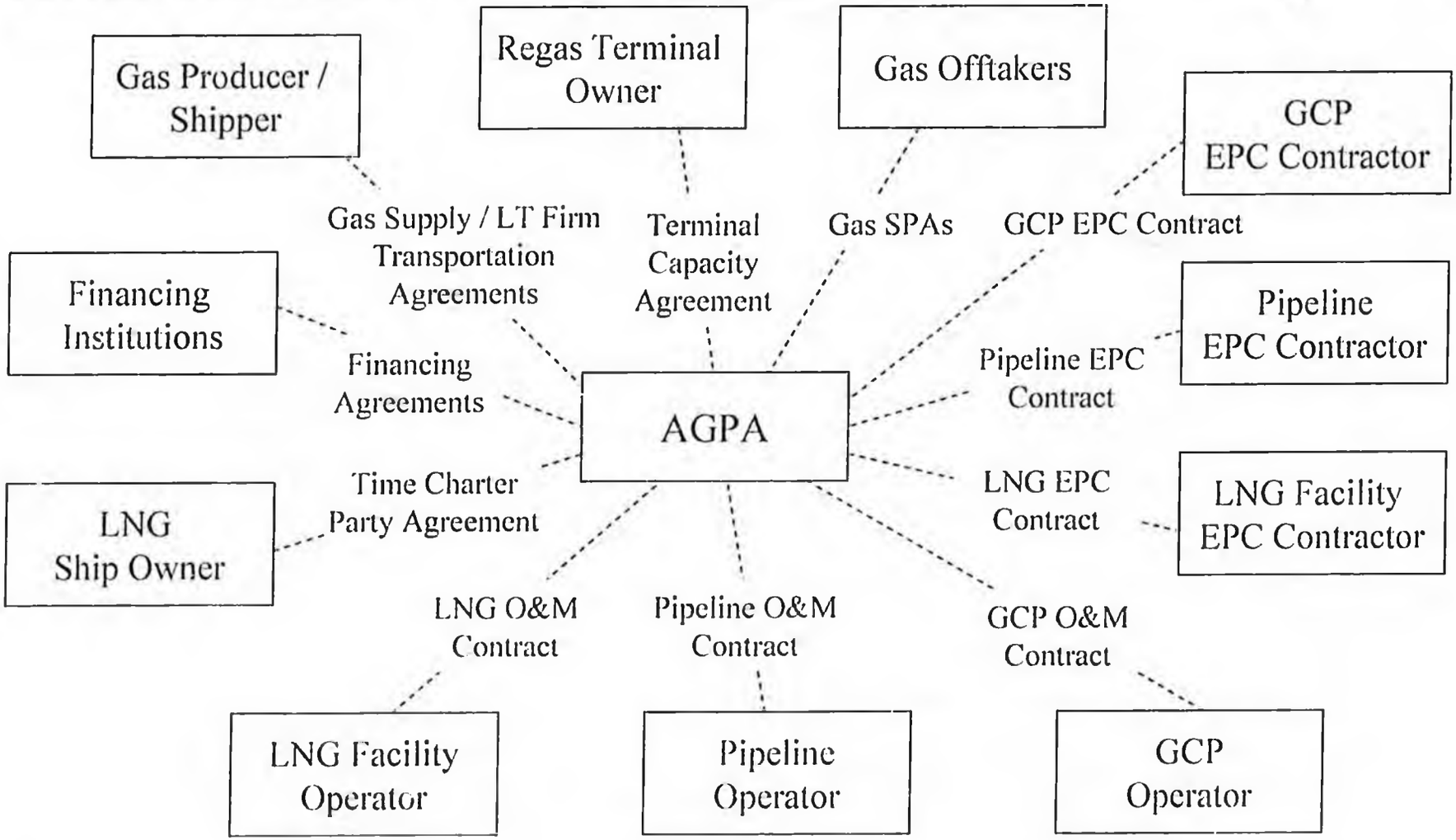
3. Bechtel Cost Estimates
   - Complete & Updated

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

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

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

Indicative AGPA Project Structure



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

AGIA is Good for Alaska

Alaska Gasline Port Authority

Alaska Gasline Inducement Act (AGIA) Process:

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

AGIA Suggested Amendments

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

AGIA benefits towards advancing gas pipeline

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

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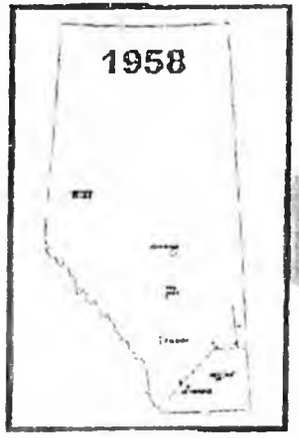
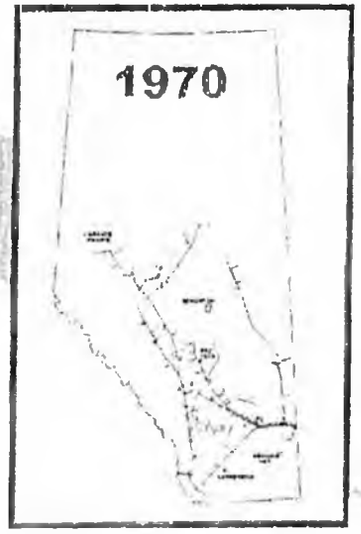
TransCanada - Proven Basin Developer





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

TransCanada

Legal Notice

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

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

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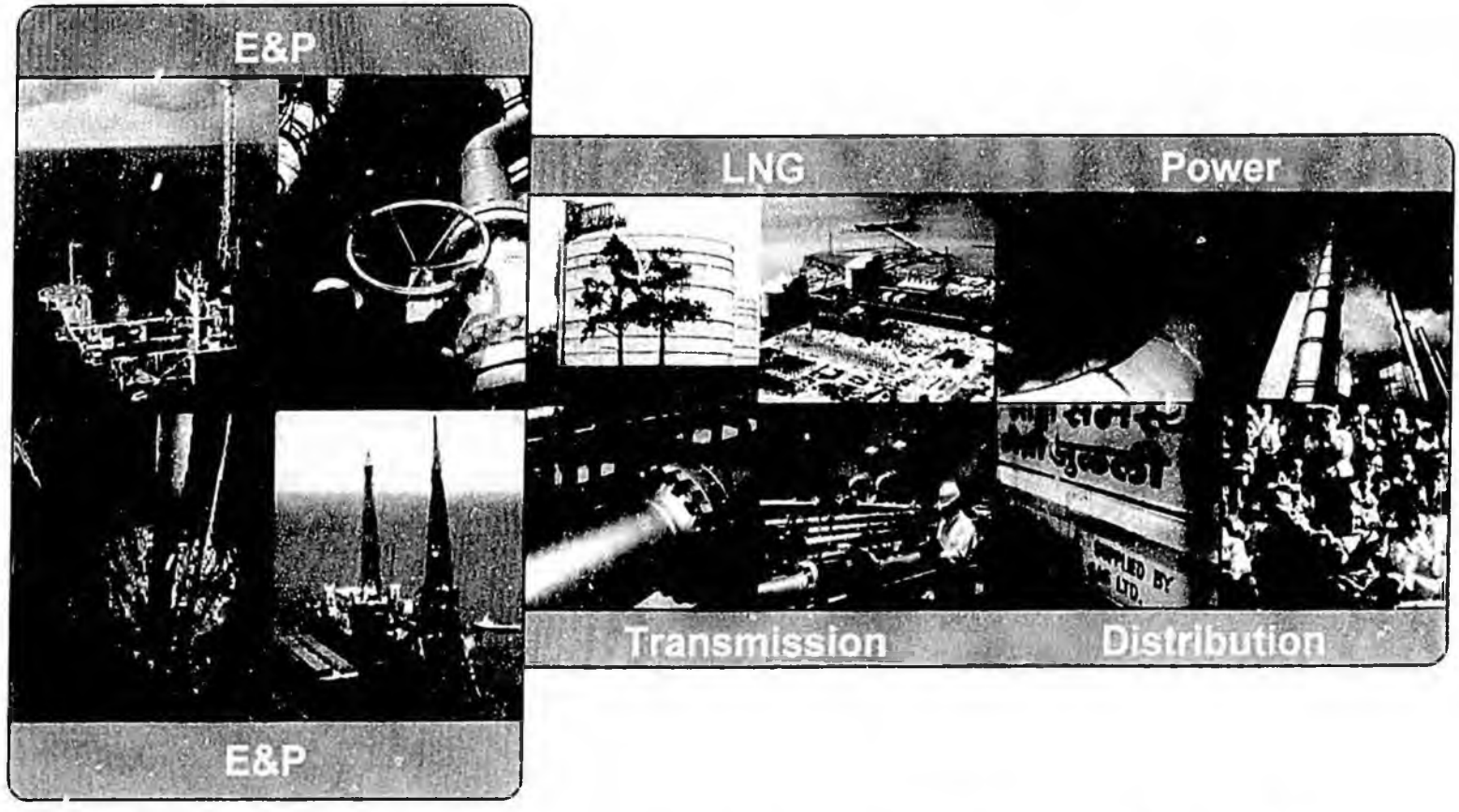
BG Group snapshot

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

Business model

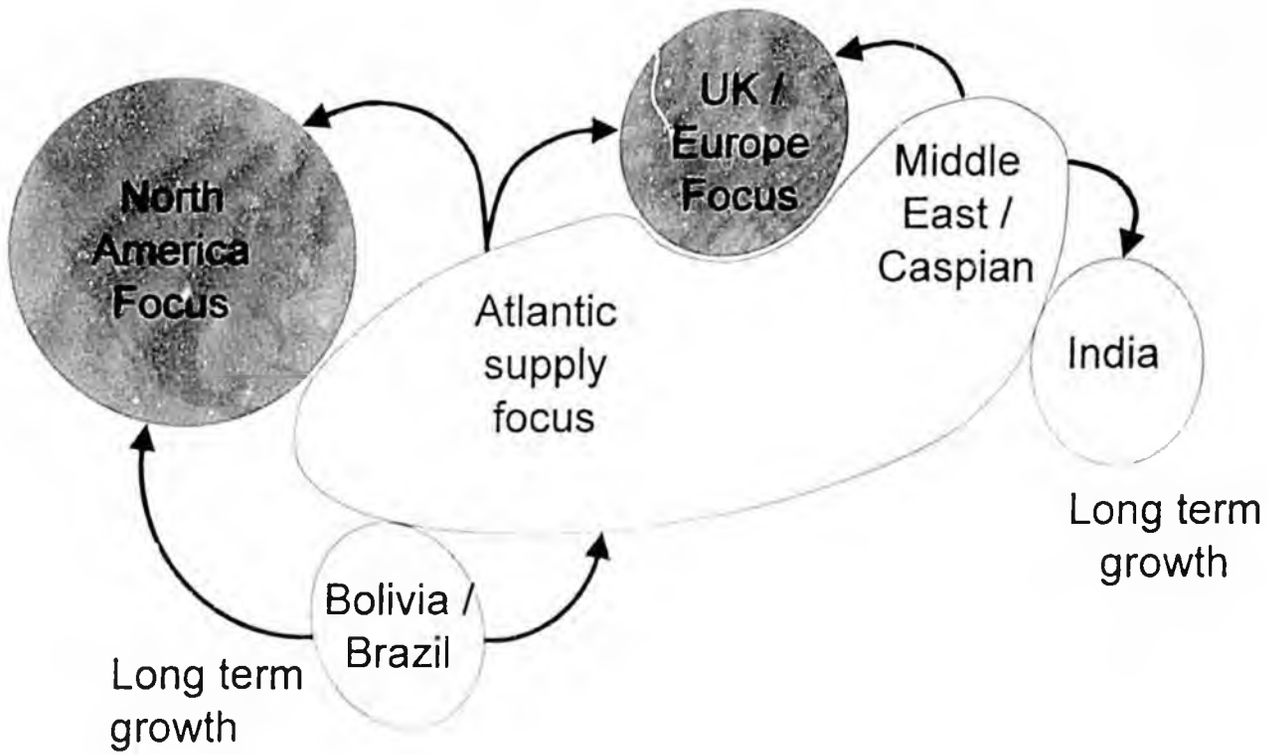


Resources → Enabling → Markets

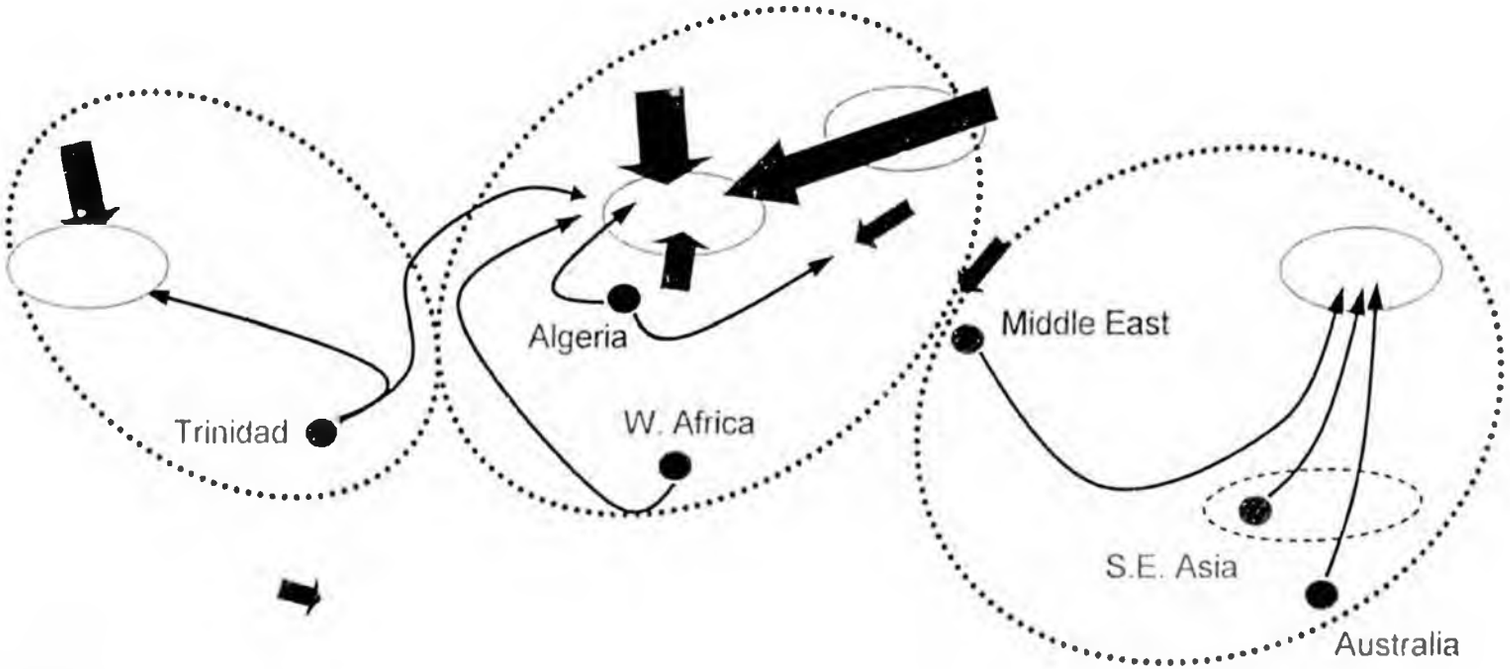
Countries of current operation

Active in over 25 countries

Gas market focus



Global gas trade – the recent past



Markets

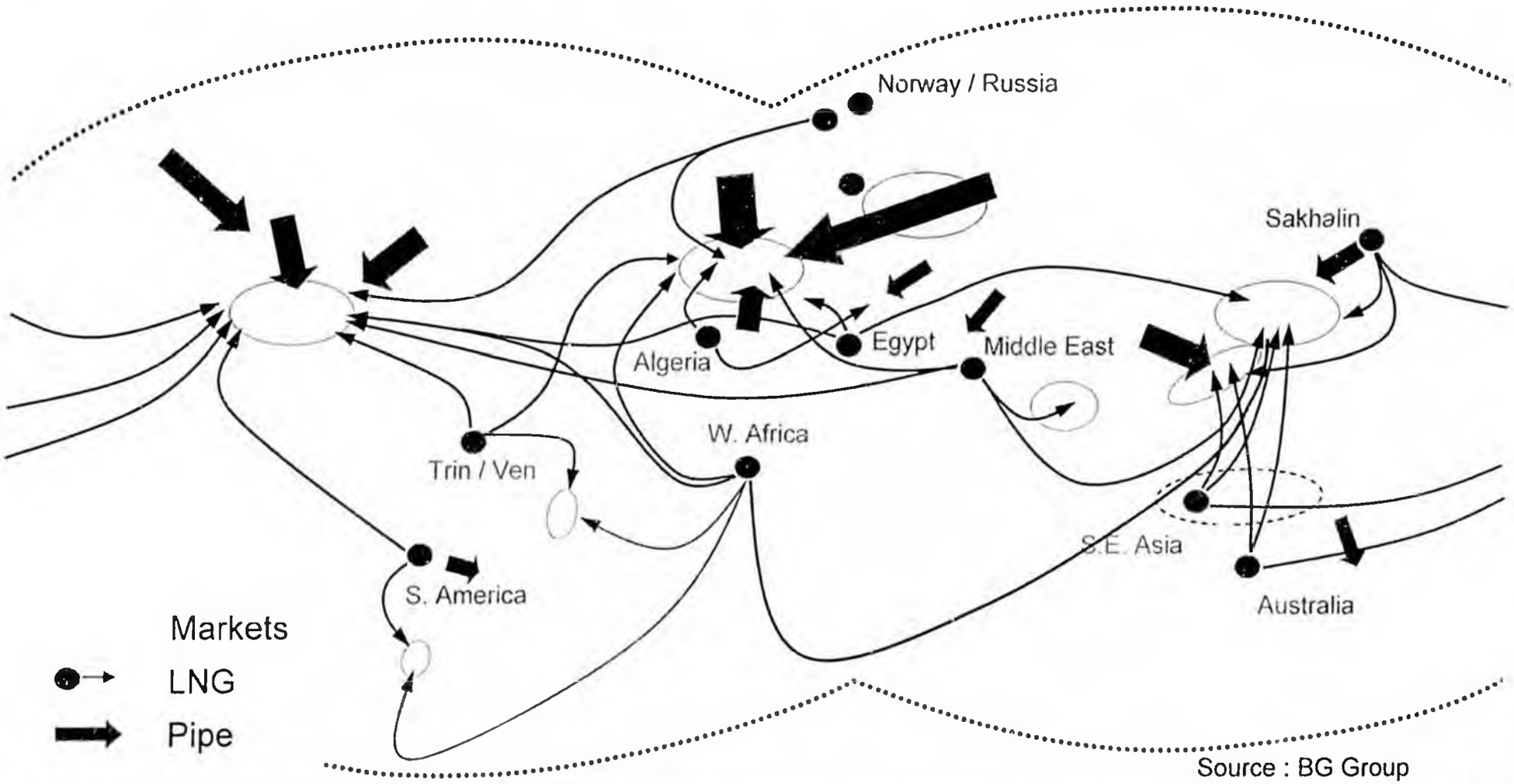
LNG

Pipe

Source : BG Group

Industry evolution: from three main trade regions…

Global gas trade – gradually evolving



Source : BG Group

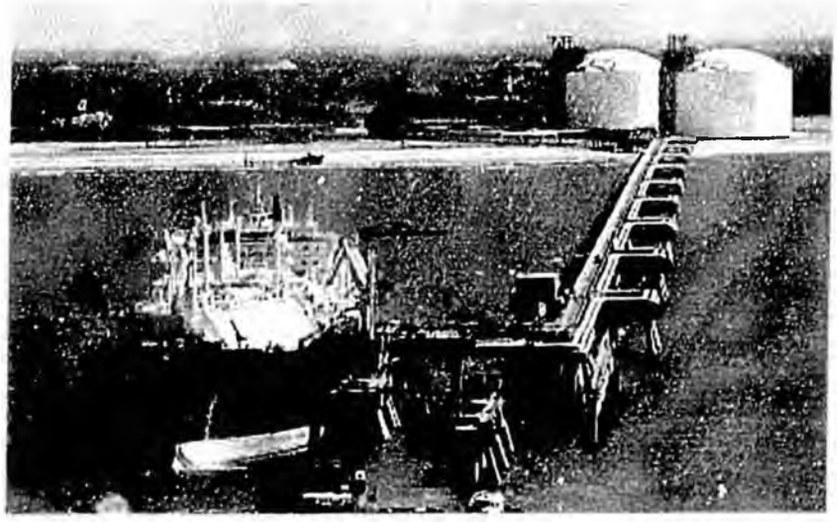
... to a globalising gas industry

BG LNG supply projects

ATLANTIC LNG
COMPANY OF TRINIDAD AND TOBAGO

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

Liquefied Natural Gas
Egyptian LNG

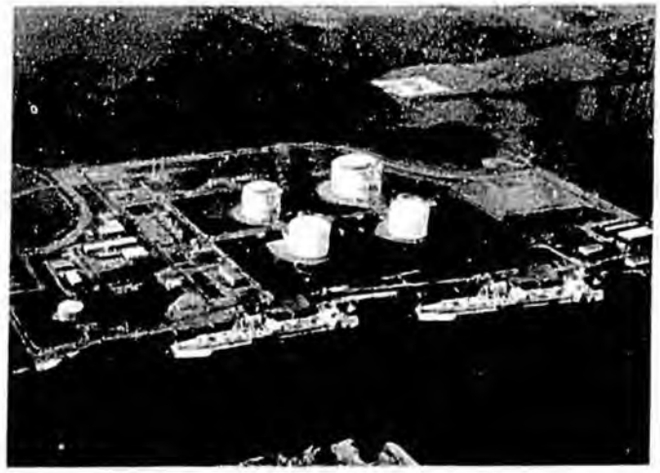


- Train 1: 3.6 mtpa – 2005 (BG 35.5%)
- Train 2: 3.6 mtpa – 2005 (BG 38.0%)
- Egypt's largest project financing to date
- Unique project commercial structure
- Utilized lessons learnt from ALNG

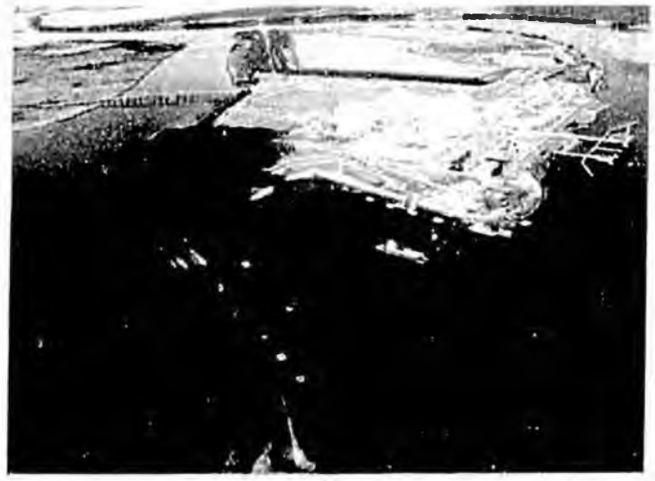
Atlantic LNG – total export capacity of 15 mtpa in just 7 years

US market summary

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



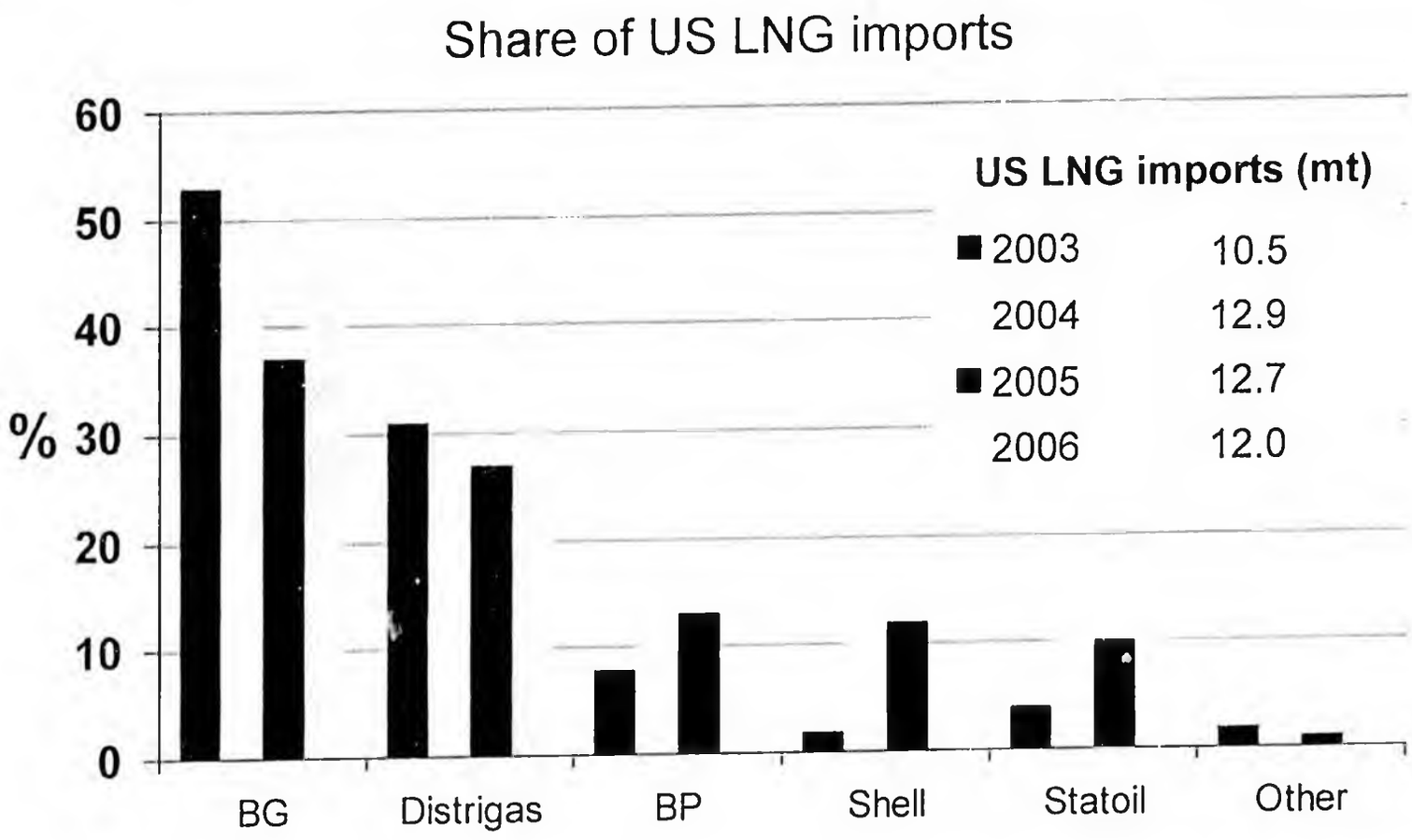
Lake Charles



Elba Island

Capacity in two of the four existing US onshore terminals

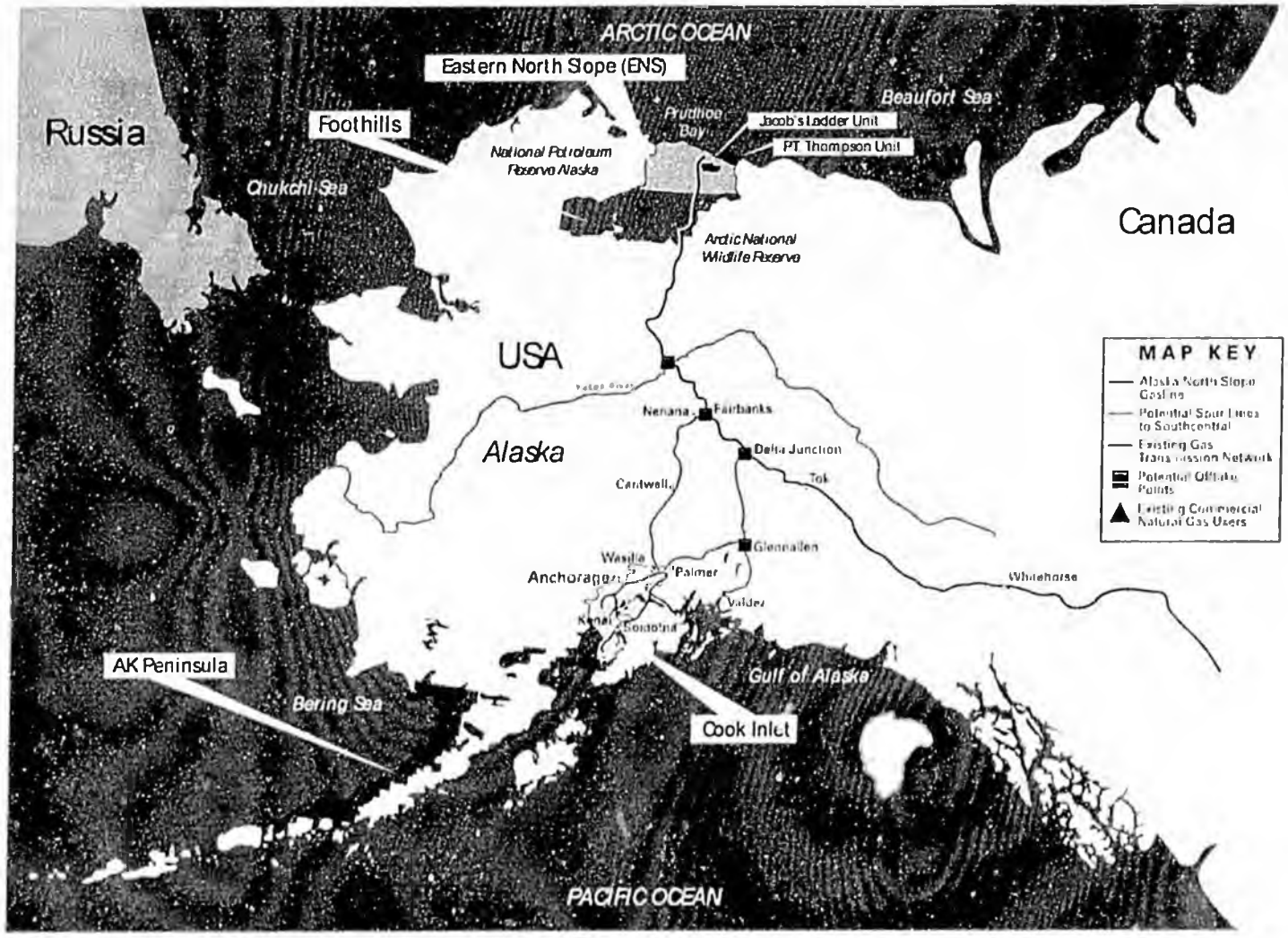
LNG imports – 2003 to present



Source : DOE

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

Alaska E&P



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

Alaska Gasline Inducements Act

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

AGIA will encourage development

Alaska Gasline Inducements Act

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

AGIA will encourage development

Key messages

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

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

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

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

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


BG North America
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minutes 5/4/07

The Palin-Parnell Administration presents

AGIA

The Alaska Gasline Inducement Act

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

The Lenders' Perspective

AGIA
The Alaska Gasline Inducement Act

Lenders consider 5 Cs:

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

Financing Perspective

AGIA
The Alaska Gasline Inducement Act

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

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

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

Firm Transportation (FT) Commitments

AGIA
The Alaska Gasline Inducement Act

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

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

Equity Commitments

AGIA
The Alaska Gasline Inducement Act

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

Cost Overruns

AGIA
The Alaska Gasline Inducement Act

- Mitigating cost overruns is a key financing concern

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

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

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

Department of Energy Loan Guarantees

AGIA
The Alaska Gasline Inducement Act

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

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

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

Conclusions

AGIA
The Alaska Gasline Inducement Act

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

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

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

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

minutes 5/4/07

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

In summary:

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

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

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

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

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

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

BIOGRAPHICAL INFORMATION

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

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

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

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

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

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

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

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

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

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

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

4. Paragraph 3 of the Principles provides that

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

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

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

5. The undersigned

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

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

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

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

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

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

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

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

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

AOGCC EMPLOYEE OR CONSULTANT

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

EXXON MOBIL CORPORATION

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

PRINCIPLES GOVERNING COMMISSION ACCESS TO POINT THOMSON UNIT RESERVOIR STUDY PROCESS

Principles Applicable to the Study Process

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

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

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

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

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

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

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

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

(b) major assumptions used in simulations such as

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

(ii) fuel usage assumptions.

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

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

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

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

Relationship of the Study and Study Process Principles

to Other Commission Responsibilities and Actions

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

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

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

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

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

AOGCC EMPLOYEE OR CONSULTANT

Signature _____
Name: _____
Title: _____
Date: _____

EXXON MOBIL CORPORATION

By: _____
Name _____
Title: _____
Date: _____

MEMORANDUM STATE OF ALASKA

ALASKA OIL AND GAS CONSERVATION COMMISSION

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

DATE: February 28, 2007

FROM: Jane Williamson
Sr. Reservoir Engineer

SUBJECT: Prudhoe Major Gas Sales Study

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

Foreward – Historical Review and Study Purpose

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

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

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

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

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

Summary of 2006 Commission Audit Results

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

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

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

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

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

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

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

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

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

Recommendations

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

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

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

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

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

Prudhoe Oil Pool
Gas Offtake Reservoir Study

Public Summary

February 28, 2007

Presentation Summary

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

AOGCC Major Gas Sales Reservoir Study Disclaimer

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

Prudhoe Gas Offtake Allowable Commission Authority

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

Prudhoe Gas Offtake Allowable Historical

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

Why do we care about gas offtake?

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

Prudhoe Gas Offtake Allowable Recent Activities

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

Prudhoe Gas Offtake Study

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

Study Approach

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

Conclusions

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

Conclusions - Model

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

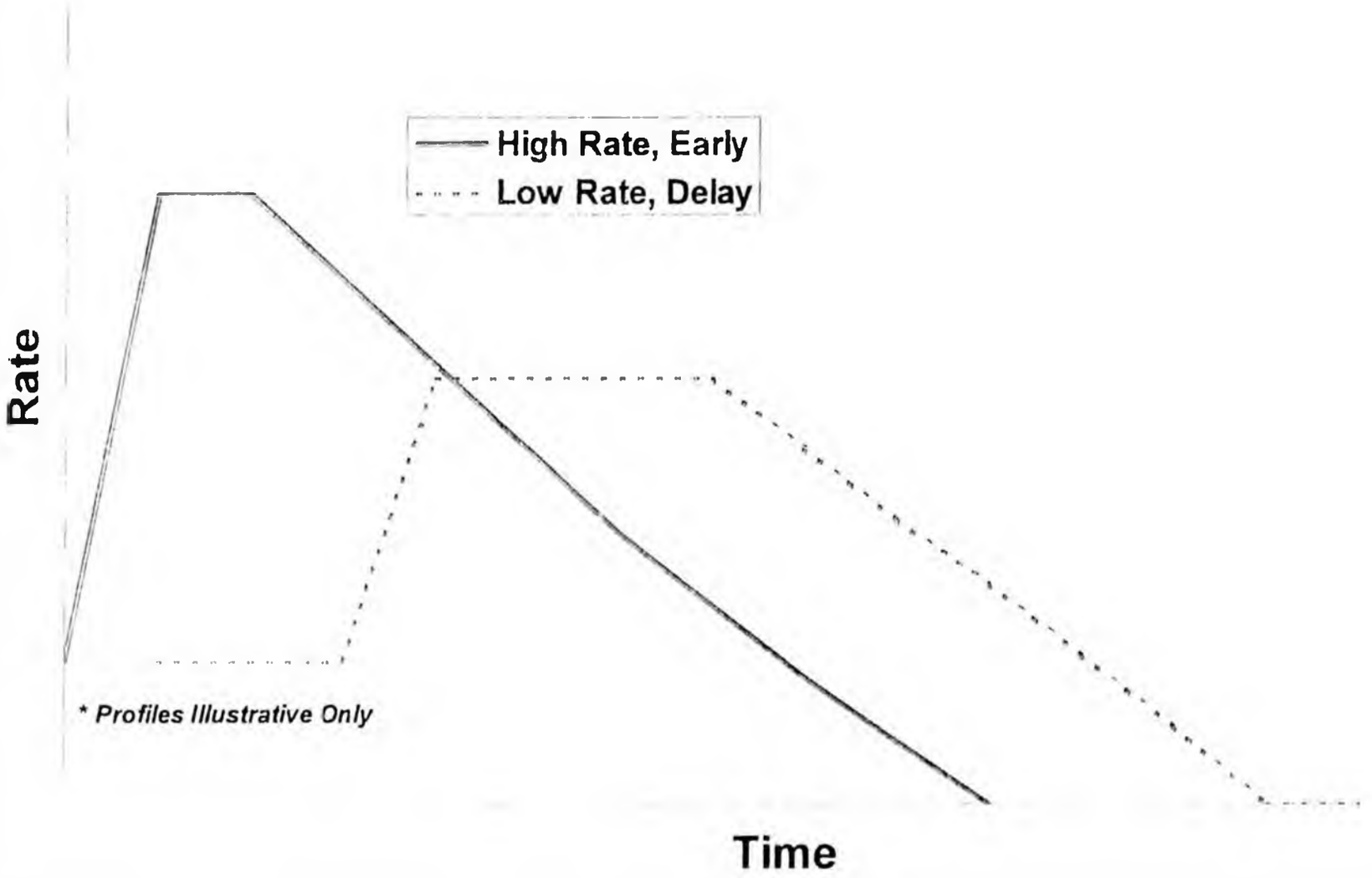
Conclusions

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

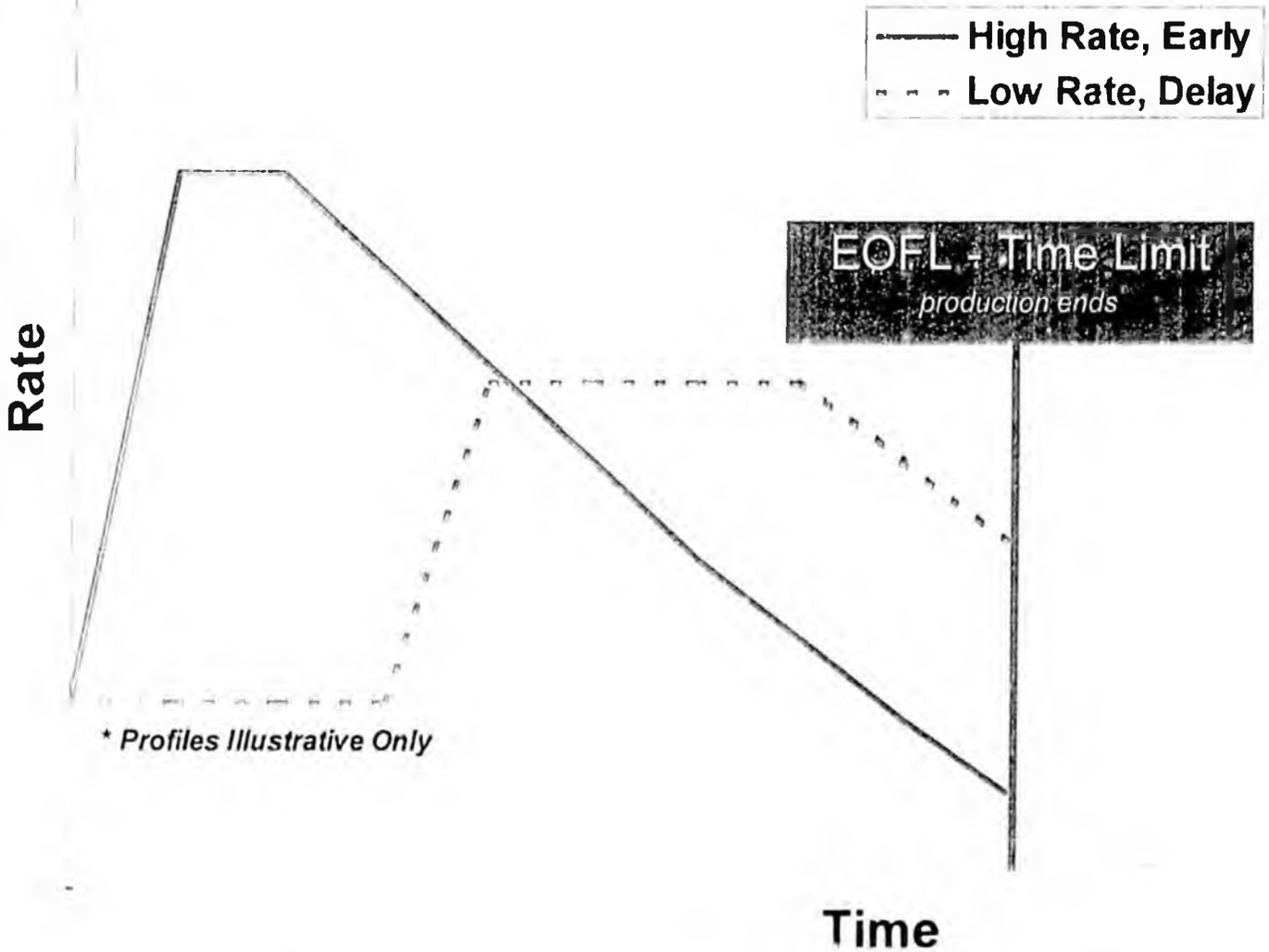
End of Field Life (EOFL)

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

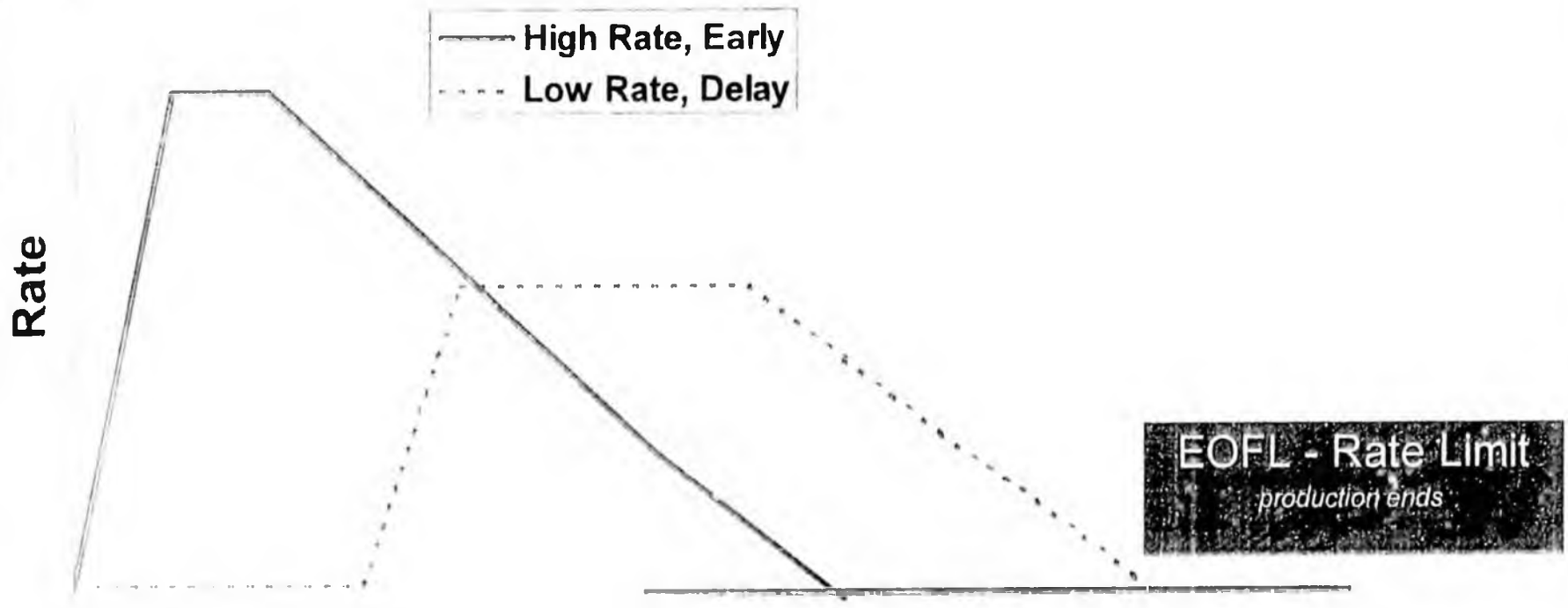
Hypothetical Profiles*



Hypothetical Profiles*
EOFL - Time Limit



Hypothetical Profiles*
EOFL - Rate Limit



** Profiles Illustrative Only*

EOFL Summary

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

Field Well/Infrastructure Failures

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