BG Group

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Senate Resources Committee

David Keane • Juneau • March 21

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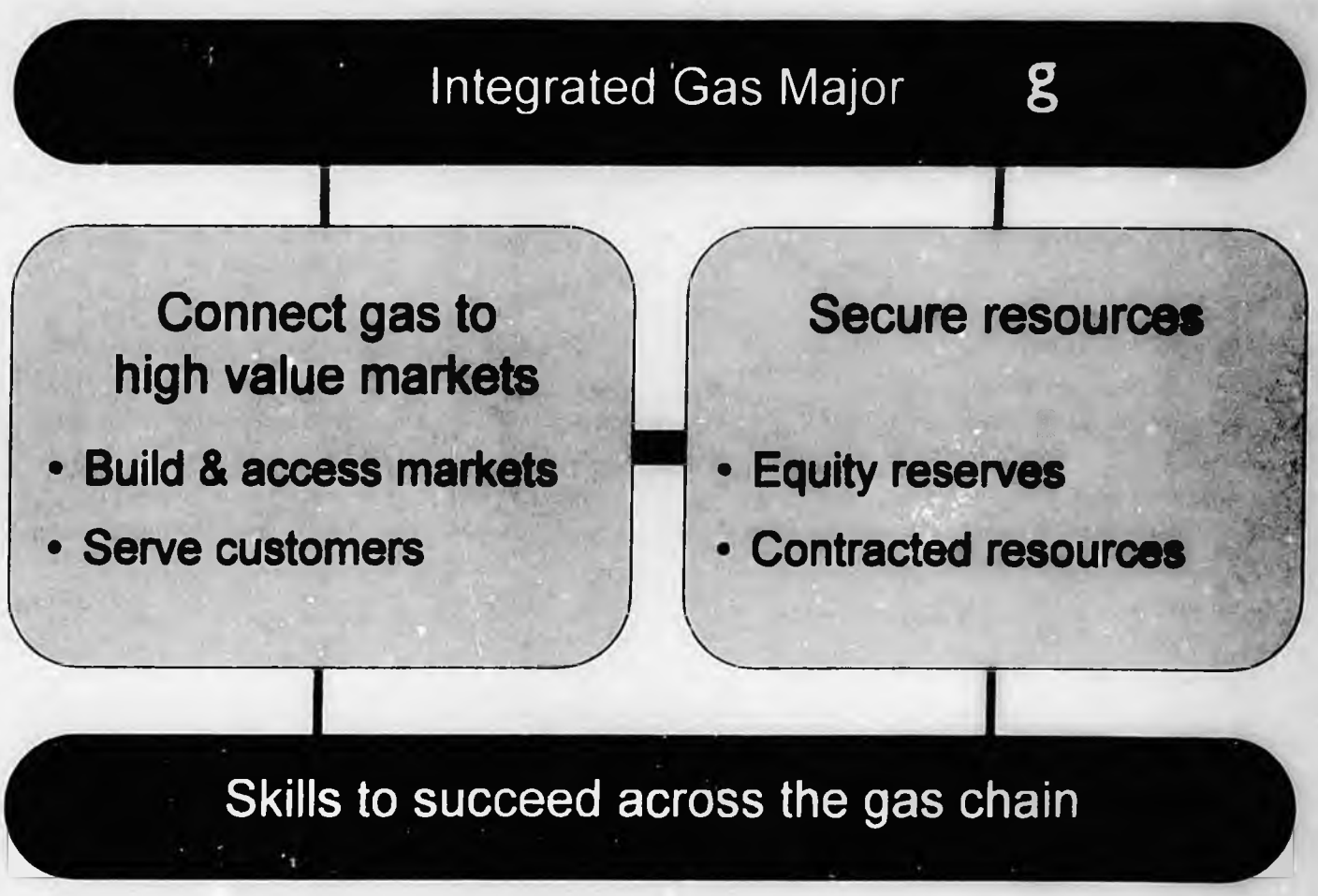
BG Group

- Integrated gas major
  - Long heritage in natural gas
- Activities span the natural gas chain
  - Exploration & Production
  - LNG
  - Transmission & Distribution
  - Gas Fired Power Generation
- A top 20 UK company
- Market capitalisation
  - Over $45 billion
- A global player
  - Active in 25 countries

BG Group

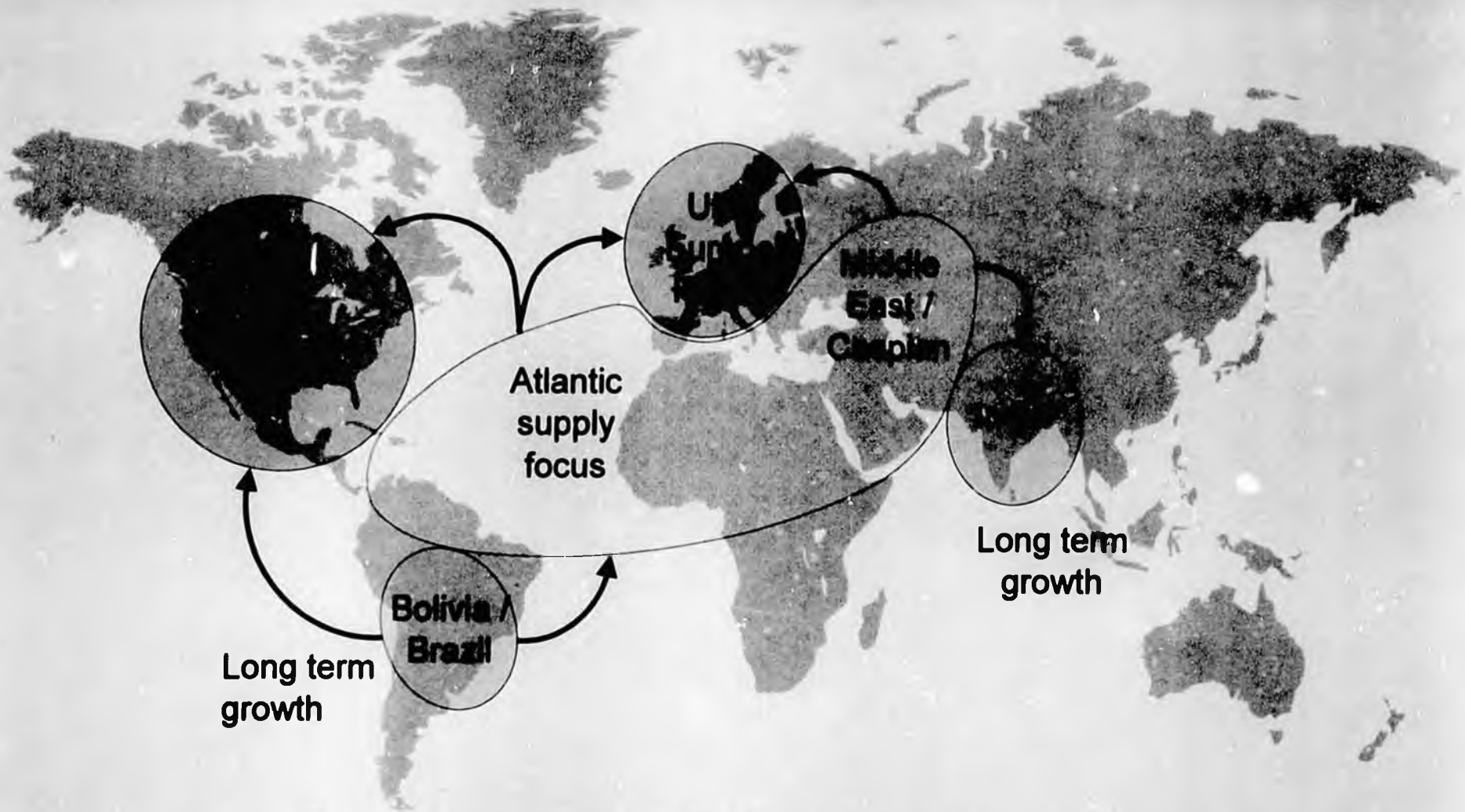
Integrated Gas Major



Connecting high value markets to resources

Strategy

Gas market focus



Strategy

Countries of current operation

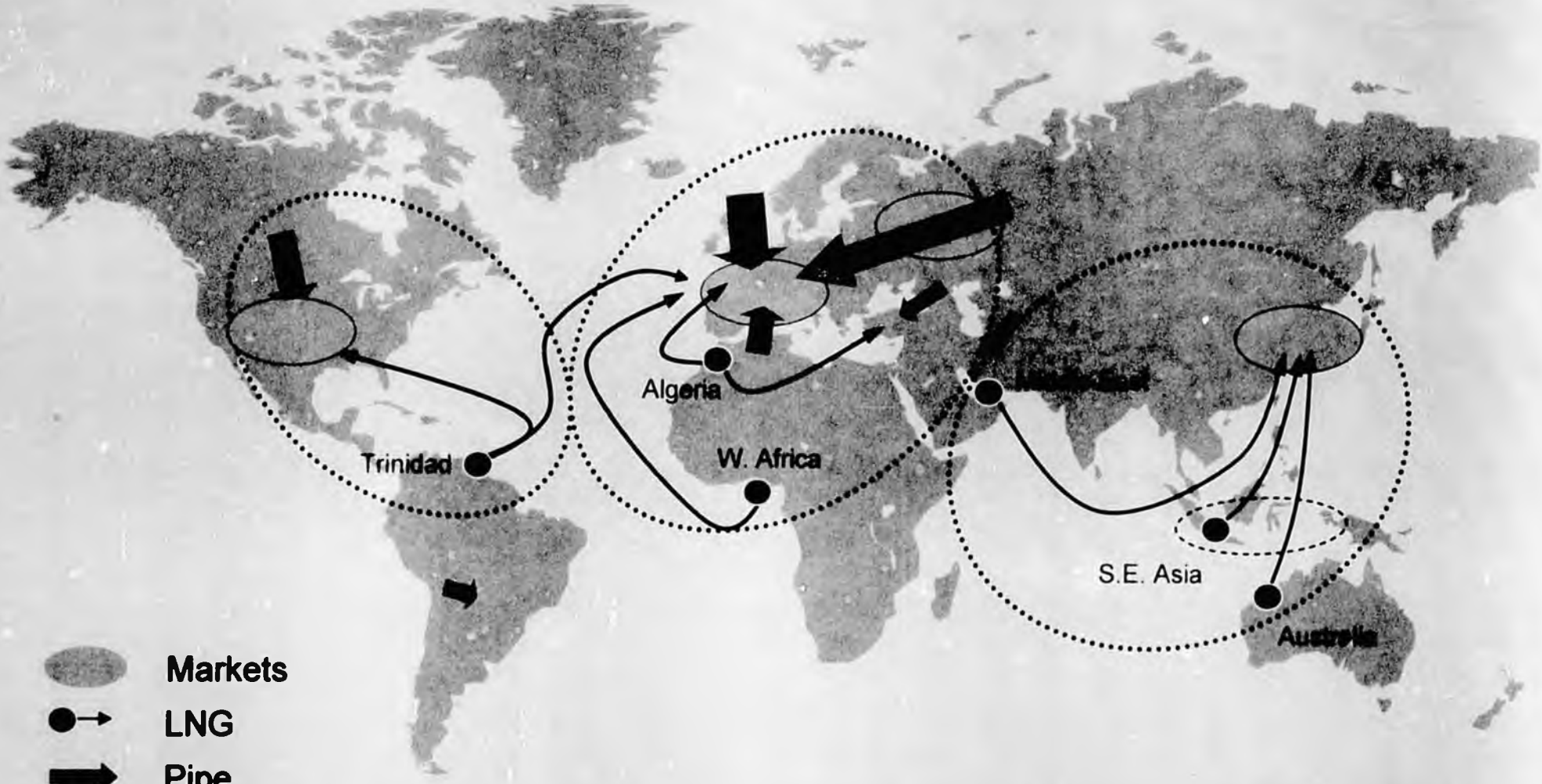
BG Group's LNG portfolio

Atlantic LNG

Lake Charles

BG Group

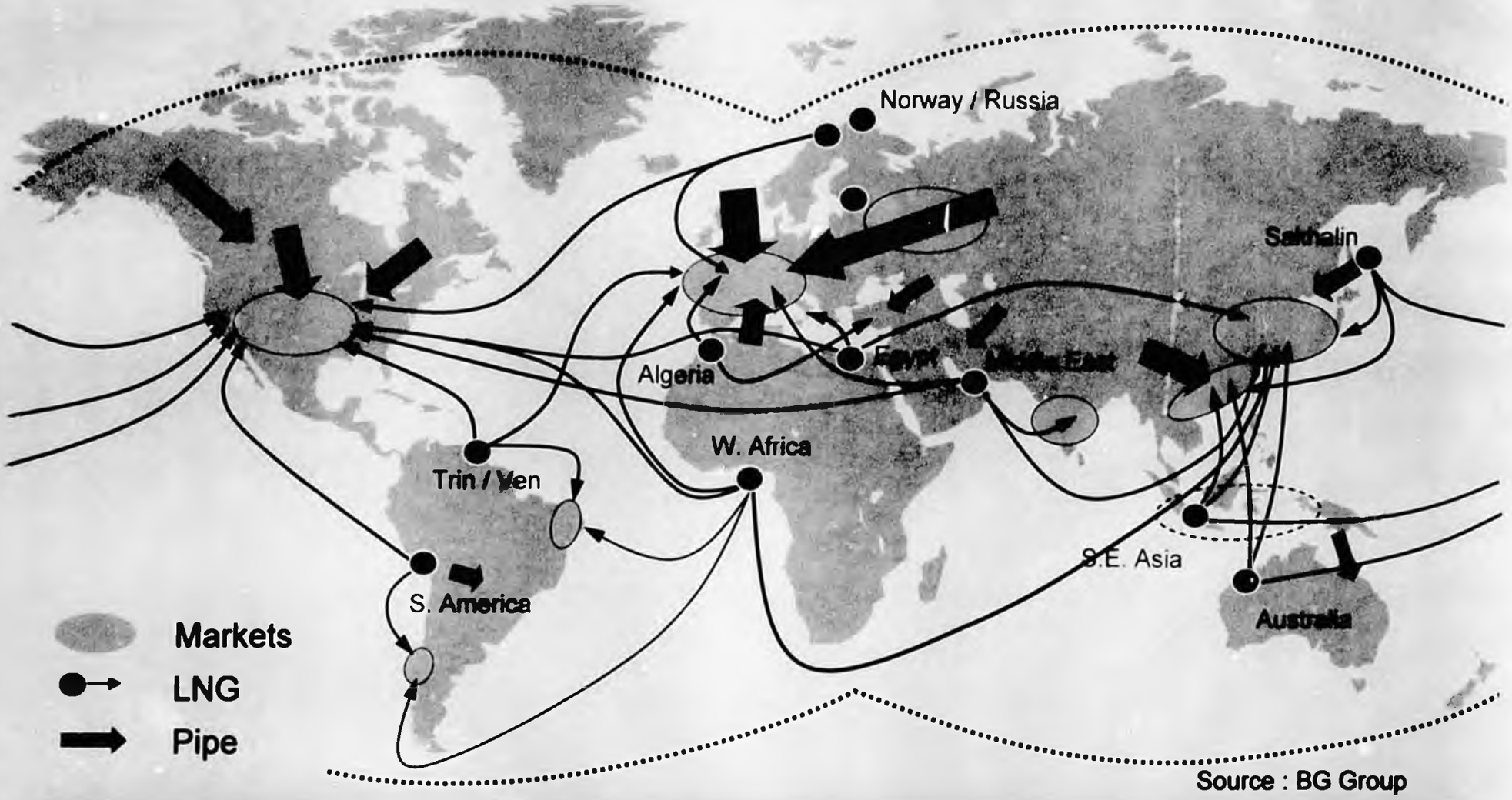
Global gas trade – the recent past



Source : BG Group

BG Group

Global gas trade – gradually evolving

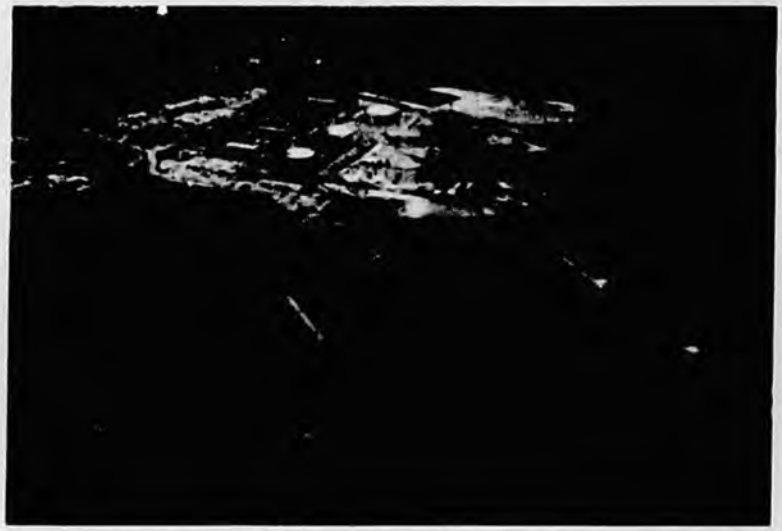


Source : BG Group

BG LNG

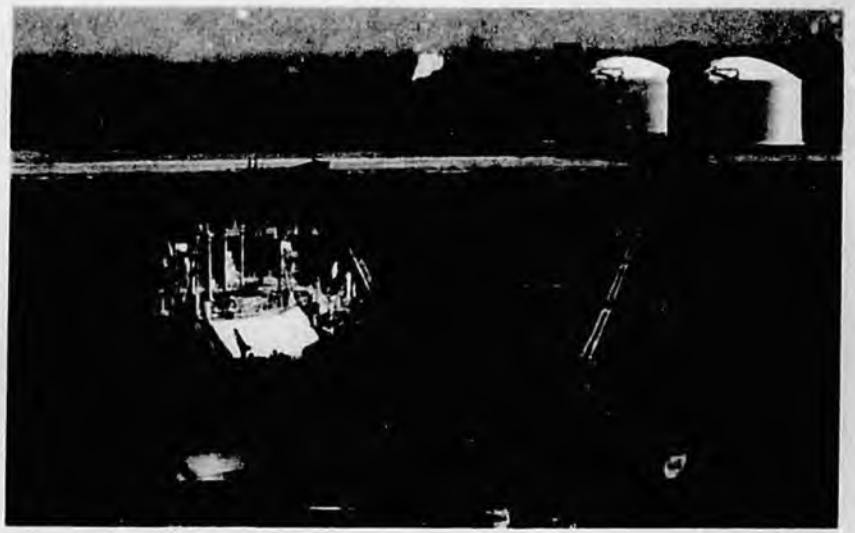
Supply projects

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

Market summary
US

- 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

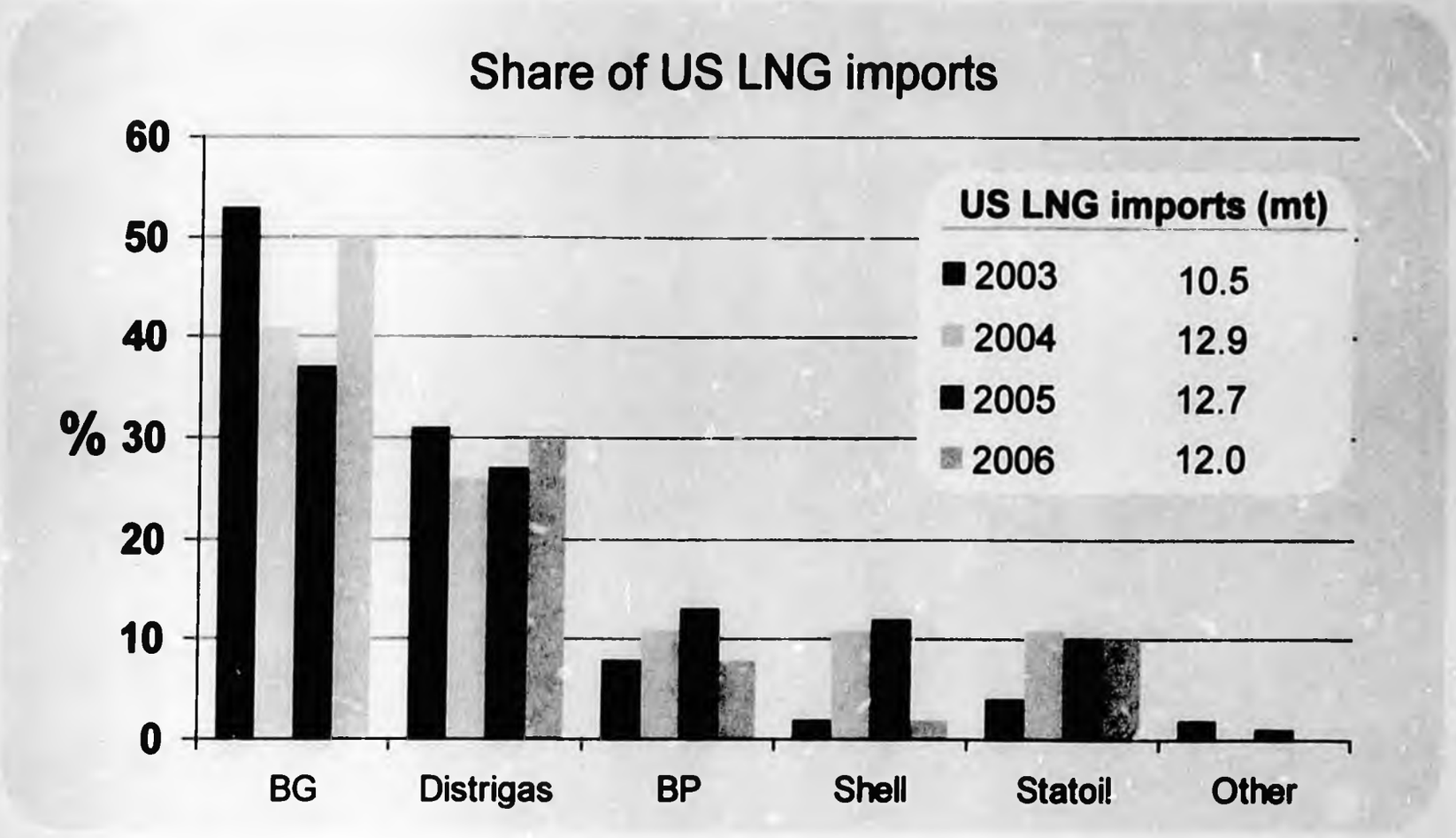
Lake Charles

Elba Island

Capacity in two of the four existing US onshore terminals

US LNG imports

2003 to present



Source : DOE

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

BG LNG Shipping

BG shipping capacity

- 4 Golar ships (chartered)
- Methane Princess (20-year charter)
  - Golar new-build delivered early 2004
- Methane Kari Elin (long-term lease)
  - Samsung new-build delivered mid 2004
- Methane Rita Andrea, Methane Jane Elizabeth & Methane Lydon Volney
  - Samsung new-build delivered April, June and August 2006
- 3 new ships scheduled for delivery
  - Samsung new-builds delivery 2007
- 2 new ships scheduled for delivery
  - Samsung 170,000 m^3
  - Delivery 2010

Methane Rita Andrea

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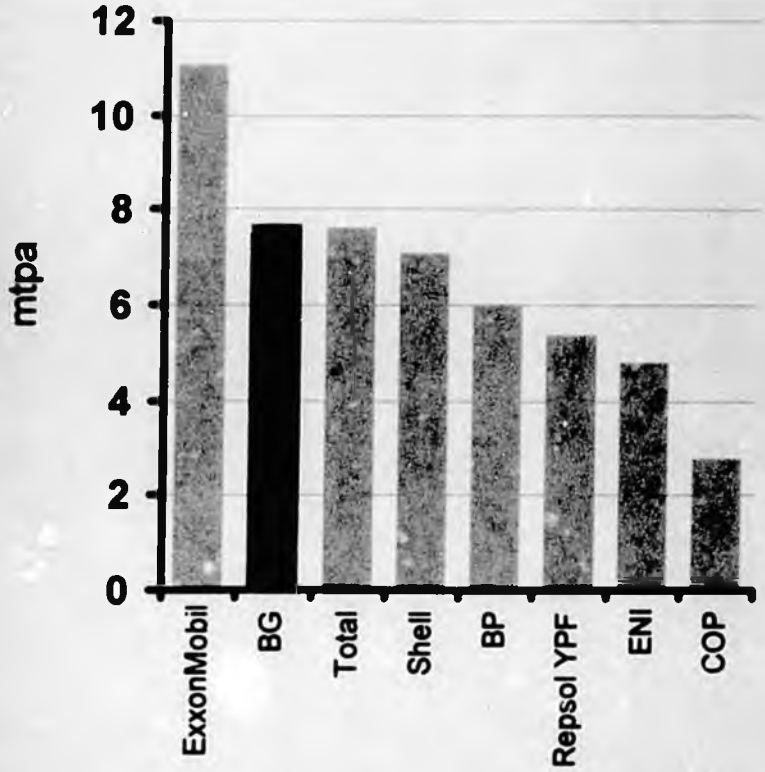
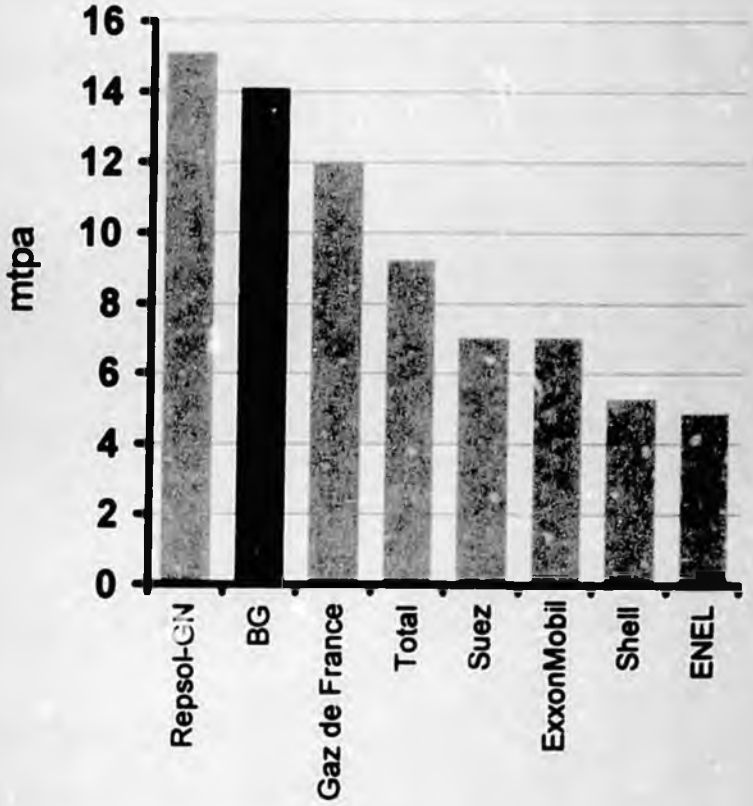
Atlantic Basin position – 2010

Liquefaction capacity 2010



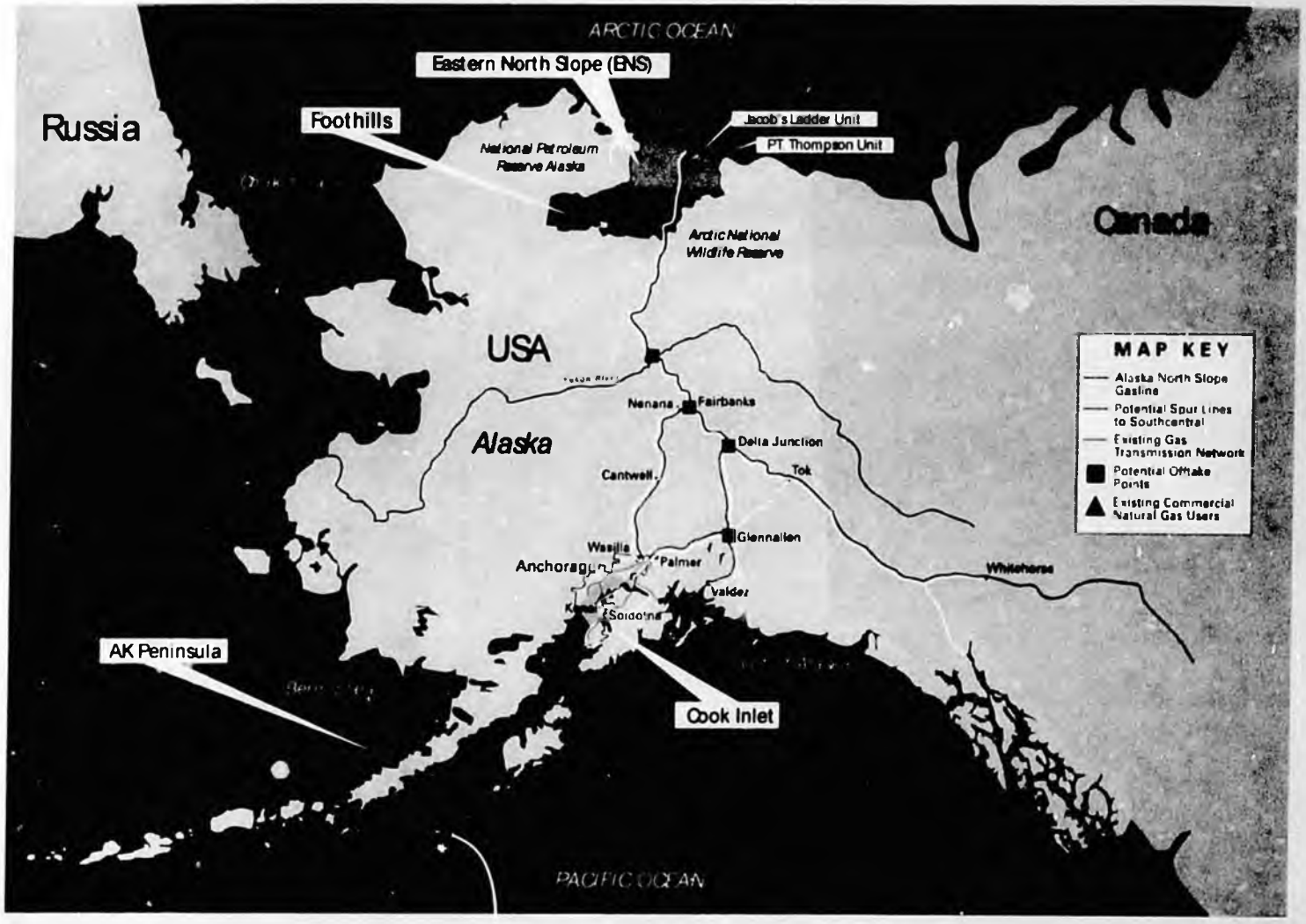
LNG contracted for purchase – 2010



Source: BG based on WoodMcKenzie data – June 2006

BG has the largest combined liquefaction and purchase position

Alaska
Overview



2.1 million acres in the Foothills of ANS

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Key messages

- BG is investing in Alaska
  - Signed agreements to explore along North Slope and ENS
- BG is a leading player throughout the natural gas value chain
  - Leading player in LNG - BG is interested in exploring the LNG option
- BG supports a pipeline contract, but:
  - Had serious concerns about the previous draft contract
  - Contract must provide a level playing field for all participants
  - Contract must provide reasonable certainty that when we discover gas, we will have access to pipeline capacity
  - BG encourages the State to enter into discussions with independent pipeline companies

ALASKA STATE LEGISLATURE

Sen. Charlie Huggins, Chair
Sen. Bert Stedman, Vice Chair
Sen. Lyda Green
Sen. Gary Stevens
Sen. Lesil McGuire
Sen Bill Wielechowski
Sen. Thomas Wagoner

State Capitol, Room 119
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Senate Resources Committee

Senate finance Room 532

Thursday, March 22, 2007

AGENDA

- **SB 104 – Natural Gas Pipeline Project**
  "An Act relating to the Alaska Gasline Inducement Act; establishing the Alaska Gasline Inducement Act matching contribution fund; providing for an Alaska Gasline Inducement Act coordinator; making conforming amendments; and providing for an effective date."

4:15-6:15

Continuation of 3/21/07 Meeting

Chevron

By Teleconference

Vince LeMieux, New Ventures Alaska, Manager

Tim Houston, Commercial Manager Alaska

Testimony By Invitation

Greenberg Traurig

Memorandum

TO: Commissioner Pat Galvin (Department of Revenue) and Commissioner Tom Irwin (Department of Natural Resources)

FROM: Donald C. Shepler

DATE: March 21, 2007

RE: Lower-48 examples of pipeline companies taking risk for cost overruns

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The attached memo and accompanying chart shows that in *today's* world, pipeline companies in the Lower-48 and their shippers are working out mutually agreeable terms for *sharing* the risks of cost overruns associated with major expansions and new pipeline projects.

Rockies Express ("REX") is the most recent example. REX is estimated to cost $4 billion and carry 2 Bcf/day 1,600 miles from the Rockies to pipeline interconnections in the East. The first leg of the pipeline went into service in February, and the final environmental impact statement for the second leg was issued by FEC on March 16.

REX offered shippers three rate options in its open season:

1) Regulated, cost-based recourse rates;
2) Fixed negotiated rates; or
3) Negotiated rates that are adjustable between a floor and a ceiling depending on the cost of steel.

By selecting one of the negotiated rate options shippers are insulated from the effect of cost overruns on the project whereas the regulated, recourse rate shippers may be exposed to higher rates if the project costs are higher than planned.

As shown on the chart attached to the memo, all three North-slope producers have some fixed rate contracts for transportation on Lower-48 pipelines. This is further confirmation of the point that shippers can insulate themselves from cost overruns as well as future rate increases due to other factors.

Greenberg Traurig

Memorandum

TO: Antony Scott cc: Donald C. Shepler

FROM: Kenneth M. Minesinger

DATE: March 20, 2007

RE: Examples of New Pipeline Projects That Have Used Negotiated Rates To Allocate the Risk of Potential Cost Overruns

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Introduction and Summary of Conclusions

This memorandum provides a summary of how a number of pipelines and their shippers have agreed contractually to share or otherwise allocate the risk of cost overruns for new pipeline projects and expansions. Reported decisions of the Federal Energy Regulatory Commission ("FERC" or "Commission") contain several examples of risk-sharing agreements, although relatively few that expressly address the risk of increases in the price of steel and other specific factors that can affect the cost of constructing a new pipeline. Thus, in addition to reviewing relevant FERC orders, we also reviewed open season notices, precedent agreements, and other publicly available materials. Our review disclosed a number of examples of pipeline/shipper risk sharing agreements, enabling us to reach the following conclusions:

- The recent Rockies Express project gave shippers several contracting options, including the option of negotiating a contract that required the pipeline and shipper to share the risk of cost overruns with a certain range, or a contract that required either the pipeline or the shipper to bear the risk of overruns above or below a fixed rate level.

- The Alliance project also negotiated a cost sharing arrangement with its shippers, with the pipeline agreeing to bear the risk of cost overruns that would have reduced its return on equity to 10 percent if fully realized.
- In the early 1990s, the Mojave Pipeline project, constructed contemporaneously with Kern River to serve customers in south-central California, negotiated contracts with its shippers that, prior to the in-service date, were linked to the price of steel, and capped shippers' exposure to cost overruns above a fixed rate ceiling.
- As discussed in our prior memorandum dated March 12, 2007, FERC strongly encourages pipelines to negotiate agreements with their shippers allocating the risk of cost overruns for major construction projects. There are a number of examples where pipelines and shippers have negotiated *fixed rate contracts*, which allocate the risk of cost overruns above a rate cap to the pipeline, thereby insulating the shippers from the risk of cost overruns above the agreed-upon rate cap. The prevalence of situations where shippers bear the risk of cost overruns, by agreeing to pay whatever FERC ultimately approves based on the final costs of a particular project, has significantly diminished in recent years.

Discussion

1. Rockies Express

The recent Rockies Express ("REX") project provides an interesting, timely insight into how pipelines and shippers can choose to allocate the risk of cost overruns on a major new pipeline

project. REX is a "Greenfield" project that will ship growing supplies of Rockies gas to markets in the Eastern U.S., from receipt locations in Wyoming and other Rockies supply areas to the terminus of the pipeline in Ohio, where it will interconnect with downstream interstate pipelines. Upon completion of the western and eastern segments of the pipeline, REX will have a capacity of approximately 2 Bcf/day, and more than 1,600 miles of pipeline facilities. It is estimated that REX will cost approximately $4 billion.[1] In terms of capacity, length, and cost, REX is probably the single largest new long-haul, natural gas pipeline project constructed in the U.S. since the Alliance project. Thus, while it is not nearly the size of an Alaska natural gas pipeline to Canada or Chicago, the REX project offers some interesting points of comparison.

In its open season posting, REX offered all open season bidders the opportunity to elect from three rate options, which would apply for the entire term of the service agreement, with a minimum term of ten years. First, shippers could elect to pay the maximum recourse rate determined by FERC, under which the shippers would essentially bear the risk of any prudently incurred cost increases. Under this first option, and unlike the other two rate options, REX would have the discretion to propose changes in this rate at FERC during the term of a shipper's contract, based on the actual cost of the project. In its open season materials, REX estimated that the initial recourse rate to go to the furthest downstream delivery points on REX would be $1.427 Dth/day.

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[1] Information available on Kinder Morgan's website at: http://www.kindermorgan.com/business/gas_pipelines/rockies_express/; *see also* February 28, 2006 Press Release of Kinder Morgan available at http://www.kindermorgan.com/business/gas_pipelines/rockies_express/NewsRelease_0228_REX_Commitments.pdf.

(2) Second, for this same end-to-end service, REX offered Anchor shippers a fixed negotiated rate of $1.074 Dth/day.[2] This is significantly less than the estimated recourse rate of $1.427, indicating REX was willing to take a lower return on equity than that approved by FERC in order to attract sufficient load for its project, and that REX's estimated recourse rate may, from REX's standpoint, have been conservative by building in some projected increases in the cost of construction. REX also may be gambling that in future years its recourse rate will decline below the level of its negotiated rates, providing it with the opportunity to earn a higher effective rate of return on its negotiated rate service in future years.

(3) Third, for end-to-end service REX also offered Anchor shippers an adjustable negotiated rate. While the starting rate under this option was $1.074 Dth/day, it was subject to a floor rate of $1.024 and a ceiling rate of $1.124. Adjustments were tied to fluctuations in the price of steel. In an appendix to the draft precedent agreement included in its open season posting, REX described this option as follows:

> The Adjustable Negotiated Rate Option recognizes that the steel costs of the Project could change substantially between the time of execution of this Precedent Agreement and the time when the Project is placed in-service. The following rate adjustment mechanism ("Steel Price Adjustment") shall apply to Shippers electing the Adjustable Negotiated Reservation Rate Option. Any adjustment that results from this formula shall be communicated to Shipper by Transporter when all steel related Project costs have been determined.
>
> Shipper's Adjustable Negotiated Reservation Rate will be adjusted to reflect actual total steel related project costs by using the Steel Price Adjustment and is subject to the rate floors and rate caps set forth in the tables below. The negotiated rates for

[2] For each of the three options, "Anchor" shippers – shippers who agreed to firm contracts for 200-500 MMcf/day, and "Foundation" shippers – shippers who agreed to firm contracts of more than 500 MMcf/day – received slightly lower rates than non-Anchor shippers, and somewhat more favorable contract rights (such as contractual right-of-first-refusal and rollover rights).

Certificate Segments, 1, 2, and 3, including Interim Service rates, may be increased or decreased from the Starting Rate as described in the formula below:

Steel Price Adjustment =

(actual realized steel cost per ton - $ 1,275 per ton) * (actual tons of steel) / $ 1,000,000 * $ 0.0002 /Dth

The Steel Price Adjustment will be added to or subtracted from the Starting Rate(s), however the final adjusted rate will be neither higher than the Ceiling Rate nor lower than the Floor Rate ....

Thus, REX's adjustable rate option offered some protection to shippers if the price of steel went below $1,275/ton, and also gave some protection to REX if the price went above $1,275/ton. The adjustable rate option also required REX to assume the risk of steel price increases in excess of the ceiling rate, and shippers to assume the risk of steel price decreases below the floor rate. Between those levels, however, the adjustable rate option effectively results in a sharing of the risk between the pipeline and the shipper. The open season materials do not explicitly address whether either REX or its customers could void the precedent agreement if steel prices either increased above or decreased below the ceiling and floor rates, respectively. However, it appears that the parties agreed to assume the risk of changes in steel prices above and below the ceiling and floor rates.

The REX project also provides an example of how the three major producers in Alaska -- BP, Conoco, and Exxon ("Producers") -- have been able to insulate themselves, in whole or in part, from the risk of construction cost overruns on other pipeline projects. Both BP and Conoco have entered into long-term, negotiated rate precedent agreements with Rockies Express. While the agreements themselves are not publicly available, some of the key terms of the agreements are reflected in the Statement of Negotiated Rates contained in the tariff filed with the initial

application for the REX-West part of the project.[3] The BP and Conoco contracts both provide for a reservation rate of $23.5425/Dth/month, for the duration of their respective agreements. Although the tariff sheets are silent on whether BP and Conoco elected a fixed or adjustable negotiated rate (the second and third options discussed above), it would appear that they choose the fixed rate option. In either case, this rate helps to protect BP and Conoco from cost overruns above the fixed rate, which also represents a significant discount from the otherwise applicable maximum recourse reservation rate of $27.4297/Dth/month. A chart reflecting the BP and Conoco fixed rate contracts with REX, and examples of other fixed rate contracts held by the Producers, is attached to this memorandum at Appendix A.[4]

2. Alliance

The Alliance pipeline project was built in the late 1990s with a capacity of approximately 1.5 Bcf/day from supply areas in British Columbia to delivery points near Chicago, Illinois. Although the subject of steel prices was not explicitly discussed either by Alliance in its certificate application or by FERC in its orders authorizing construction of the project, a risk sharing arrangement tied to Alliance's construction costs is described in the certificate application. The Alliance case thus provides another example of how a major pipeline project and its shippers have allocated the risk of cost overruns.

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[3] *See* Rockies Express Pipeline LLC, FERC Gas Tariff, Pro Forma Second Revised Volume No. 1, Original Sheet Nos. 8-9A.

[4] We forwarded this same chart to you yesterday along with a separate cover memo, but are including it here as well because it lists various fixed rate contracts held by the Producers on the REX and Alliance projects discussed herein.

By way of background, Alliance was one of the first pipelines constructed after the implementation of the Commission's negotiated rate policy in 1996. We will provide a detailed explanation of the origin of and rationale for negotiated rates in a subsequent memorandum. Importantly, negotiated rates, as authorized by FERC, permit pipelines and shippers to agree to rates that, either now or in future years, may exceed the maximum rate approved by FERC, or differ from the rate design approved by FERC.[5] Negotiated rates gave pipelines and shippers the ability to craft creative rate agreements that, among other things, allocated the risk of cost overruns in a way that would not be possible if they were required simply to pay the maximum FERC-approved recourse rate.

Alliance and its shippers contractually agreed to negotiated rates that were predicated on a 12 percent return on equity ("ROE") for the life of the shippers' contracts. The core of the risk sharing agreement was that the 12 percent ROE was subject to adjustment for changes in construction costs. The base ROE of 12 percent was subject to an incentive mechanism under which each 10 percent deviation from the estimated capital costs to construct the pipeline would result in a 0.5 percent inverse adjustment to the base ROE. The incentive adjustment was limited to a plus or minus 2.0 percent (200 basis points) adjustment in the 12.0 percent base ROE.[6] In

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[5] *Alternatives to Traditional Cost-of-Service Ratemaking for Natural Gas Pipelines: Regulation of Negotiated Transportation Services of Natural Gas Pipelines*, 74 FERC ¶ 61,076, *order on clarification*, 74 FERC ¶ 61,194, *reh'g denied*, 75 FERC ¶ 61,024 (1996) ("1996 Negotiated Rate Policy Statement").

[6] *See* Alliance certificate application, FERC Docket No. CP97-168, at p. 20 (filed December 24, 1996); *Alliance Pipeline L.P.*, 80 FERC ¶ 61,149, at 61,592 (1997).

essence, therefore, Alliance assumed the risk of a two percent reduction in its ROE due to steel price increases, from the base ROE of 12 percent to a floor ROE of 10 percent.[7]

3. Mojave

Not surprisingly, efforts by pipelines and shippers to allocate the risk of constructing new projects predated the advent of negotiated rates at the Commission in 1996. Perhaps the best reported example involves the construction of the Mojave Pipeline Company facilities in the early 1990s. Mojave was constructed at the same time as Kern River Gas Transmission Company. Both Kern River and Mojave were built largely to serve enhanced oil recovery loads located near Bakersfield, California. Mojave constructed a 400 MMcf/day pipeline originating at the Arizona/California border at interconnections with two upstream pipelines, where Mojave receives gas produced in the southwestern U.S. Kern River's original facilities had a capacity of 700 MMcf/day, and originate in Rocky Mountains production areas. The facilities of Kern River and Mojave, which each commenced service in early 1992, merge at a point near Daggett, California to form a common, "undivided interest" pipeline which ships a commingled stream of gas to each pipeline's customers near Bakersfield. Although they share the same, common pipeline facilities downstream of Daggett, both pipelines compete for customers just as if they operated physically separate pipeline facilities.

FERC's orders certificating the Mojave project discuss how Mojave and its shippers contractually allocated the risk of cost overruns, including potential increases in the price of steel,

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[7] It also should be noted that Alliance agreed to calculate the negotiated rates based on a 70/30 debt/equity ratio, regardless of the actual capitalization of the project or the capital structure approved by FERC for purposes of calculating recourse rates. *See* Alliance certificate application, FERC Docket No. CP97-168, at p. 20; *Alliance Pipeline L.P.*, 80 FERC ¶ 61,149, at 61,592 (1997).

providing an example of how a pipeline and its shippers addressed this issue in the pre-negotiated rate era. Although not required to do so, Mojave submitted its executed firm transportation service agreements ("TSAs") to the Commission for approval. In order to secure financing, Mojave had to know whether the Commission would approve or object to the agreements. *Mojave Pipeline Co.*, 56 FERC ¶ 61,282, at 62,097 (1991).

Mojave had six firm shippers, including Texaco (now part of ChevronTexaco), Meridian Oil (which became Burlington Oil, which was recently acquired by Conoco), and Mobil Natural Gas Inc. (now part of ExxonMobil). To allocate the risk of cost overruns, Mojave and its shippers agreed to discounted rates that were linked to the price of steel. As summarized by the Commission:

> Mojave negotiated a cap on its transportation charge with each customer in order to allocate the risk of construction cost overruns. In general, Mojave negotiated a cap with each customer that then would escalate pursuant to an index intended to reflect increases in the price of steel, which is expected to be the chief variable in the cost of construction of the pipeline. The exact cap and escalation factor that Mojave negotiated with each customer varies somewhat, but all are expressly subject to the maximum rate levels prescribed by the Commission.

Id. at 62,100.

Later in the order, the Commission describes Mojave's firm TSAs in more detail. For example, Meridian Oil's rate was subject to a monthly adjustment based on the applicable increase, if any, in the Pipe and Oil Country Tubular Goods, Carbon Index of the Producer Price Index, calculated from the March 1, 1990 through the date Mojave's facilities were placed in service. Texaco's rate cap could be adjusted by between 3 and 5 percent annually but no less than 3 percent

based on the applicable increase in the Steel Pipe and Tubes, Line Pipe sub-index of the Producer Price Index. Mobil's rate cap appears to have been subject to similar adjustment. *Id.* at 62,102.

In sum, while the Mojave contracts varied somewhat according to each individual shipper, the Mojave case provides another example how a pipeline and its shippers allocated the risk of cost overruns, with the parties sharing the risk within the range of certain floor and ceiling rates. *See also Mojave Pipeline Co.*, 57 FERC ¶ 61,300, at 61,958-59 (1991).

4. Other Pipelines

Our prior memorandum dated March 12, 2007 (a copy of which is attached hereto as Appendix B), discussed several pipelines that have agreed to negotiated rates pursuant to the Commission's policy which strongly encourages pipelines and shippers to negotiate cost-sharing agreements that allocate the risk of cost overruns. As discussed in our March 12 memo, pipelines which have agreed to bear the risk of cost overruns above a negotiated rate cap, with the shipper bearing overruns below the cap, include: (1) Millennium; (2) Iroquois; (3) Cheyenne Plains; (4) Rockies Express (also discussed above); (5) Gulfstream; and (6) Guardian. Several other pipelines have also negotiated cost sharing arrangements, including North Baja, which also entered into negotiated rates with its shippers.[8] We also found two instances -- the Empire and Islander East pipelines -- which had not negotiated cost sharing agreements at the time of the Commission's

[8] *North Baja Pipeline, LLC*, 95 FERC ¶ 61,259, 61,916 (2001) ("North Baja entered into long-term precedent agreements with its six shippers. All of the shippers have elected to pay negotiated rates. North Baja has filed copies of the agreements but redacted the rate information as commercially sensitive. North Baja states that it will disclose these terms through posting on its Internet web site on the first day of service, in keeping with section 284.13 of the Commission's regulations. To comply with the Alternative Pricing Policy Statement, North Baja is being required, as discussed below, to file additional information on its negotiated rates when it begins providing such service."). (Internal citations omitted).

certificate order.[9] Clearly, however, the trend is for pipelines and shippers to negotiate how to allocate the risk of cost of overruns as part of the process of entering into a firm transportation agreement.

[9] *See Empire State Pipeline*, 116 FERC ¶ 61,074, P 116 (2006) ("The Certificate Policy Statement found that the responsibility for cost overruns should be apportioned between the pipeline and the new customers that have subscribed for the new capacity, so that the overruns will not become the responsibility of the existing shippers. EPI admits that its agreement with KeySpan does not contain this risk-sharing provision. In the application, however, EPI reserves the right to revise its initial rates prior to the commencement of service to reflect the changes in construction costs, unless the parties agree otherwise.") (Internal citations omitted); *Islander East Pipeline Co.*, 97 FERC ¶ 61,363, P 105 (2001) ("The Policy Statement asserts that the risks of construction cost overruns should be apportioned between the pipeline and the new customers in their service contracts. Thus, in pipeline contracts for service on newly constructed facilities, pipelines should not rely on standard "Memphis clauses," but should reach agreement with new shippers concerning who will bear the risks of underutilization of capacity and cost overruns associated with the new construction. Islander East's precedent agreements do not contain any risk-sharing language on construction costs. If the parties agree to risk sharing agreements, Islander East must file those agreements with the Commission as non-conforming service agreements with negotiated terms and conditions. The Commission will review those agreements to ensure that they are not unduly discriminatory or preferential."). (Internal citations omitted).

Appendix A

Examples of Fixed Rate Firm Capacity Agreements Held by BP, Conoco, and Exxon[1]

Producer	Pipeline/Project	Term[2]	Negotiated Rate	Capacity
BP				
BP Energy Company	**Cheyenne Plains Gas Pipeline Co.**[3] Contract No. 21002000 Rate Sched: FT (New Pipeline)	12-1-04 to 1-31-15	$10.3417/Dth/month	40,000 Dth/d
BP Energy Company	**Rockies Express Pipeline**[4] Contract No. Unknown Rate Sched: FT (New Pipeline - "REX-West")	1-1-08 to 12-31-17	$23.5425/Dth/Month	100,000 Dth/d[5]
BP Energy Company	**Tennessee Gas Pipeline Company**[6] Contract No. 40102 Rate Sched: FT-A	7-1-02 to 6-30-07	$3.07/Dth/month	4,700 Dth/d
BP Energy Company	**Transwestern Pipeline**[7] Contract No. 100050 Rate Sched: FTS-1	6-15-02 to 6-14-17	$0.3800/MMBtu/d	15,000 MMBtu/d
BP Energy Company	**Transwestern Pipeline**[8] Contract No. 100926 Rate Sched: FTS-4 (San Juan Lateral 2005 Expansion)	5-1-05 to 4-30-15	Yrs 1-3 $0.2620 MMBtu/d Remainder of term: Max rate capped at $0.2370 MMBtu	100,000 MMBtu/d

BP Energy Company	**Transwestern Pipeline**[9] Contract No. 101079 Rate Sched: FTS-4	6-1-05 to 5-31-08	$0.2620/MMBtu/d	8,000 MMBtu/d
ConocoPhillips				
ConocoPhillips Company	**Alliance Pipeline**[10] Contract No. US5024P-01 Rate Sched: FT1	11-1-06 to 11-30-16	15.4864/Dth/month	75 MMcf/d
ConocoPhillips Company	**Alliance Pipeline**[11] Contract No. US5010P-01 Rate Sched: FT1	11-1-06 to 11-30-16	15.4864/Dth/month	51.1 MMcf/d
ConocoPhillips Company	**Alliance Pipeline**[12] Contract No. US5014 Rate Sched: FT1	12-1-00 to 11-30-15	15.4864/Dth/month	50 MMcf/d
ConocoPhillips Company	**Questar Pipeline Co.**[13] Contract #2419 Rate Sched: T-1	8-1-00 to 7-31-15	$2.96045/Dth/month	5,000 Dth/d
ConocoPhillips Company	**Rockies Express Pipeline**[14] Contract No. Unknown Rate Sched: FT (New Pipeline)	1-1-08 to 12-31-17	$23.5425/Dth/month	400,000 Dth/d
ConocoPhillips Company	**Transwestern Pipeline**[15] Contract No. 100922 Rate Sched: FTS-4 (San Juan Lateral 2005 Expansion)	5-1-05 to 4-30-15	Yrs 1-3: $0.2620 MMBtu/d Remainder of term: Max rate capped at $0.2370	100,000 MMBtu/d

ConocoPhillips Company	**Transwestern Pipeline**[16] Contract No. 100925 Rate Sched: FTS-4	6-1-05 to 5-31-09	$0.2620 MMBtu/d through 5-1-08	8,000 MMBtu/d
ExxonMobil				
ExxonMobil Gas & Power Marketing Company	**Alliance Pipeline**[17] Contract No. US5011 Rate Sched: FT1	12-1-00 to 11-30-15	$15.4864/Dth/m	30 MMcf/d
Mobil Natural Gas, Inc.	**Mojave Pipeline Co.** Rate Sched: FT-1	12-19-90 to 12-19-05	$0.3075/MMBtu[18]	20,000 MMBtu/d

[1] The information contained in this chart was compiled from a variety of publicly available sources. The principal sources of information were each listed pipeline's most recent Index of Customers Report filed with the Federal Energy Regulatory Commission (report information current as of the last quarter of 2006) and the relevant pipeline's currently effective FERC Gas Tariff. Additional information was obtained from the listed pipelines' certificate applications, FERC certificate or rate orders and other pipeline rate or tariff filings. A more detailed description of the source for the information contained in each chart entry is included in the endnotes that follow. The information in the chart reflects a review of material concerning about 20 of more than 150 FERC-regulated natural gas pipelines. It is also important to note that the producers considered here have entered into fixed discount rate agreements with various pipelines that are not contained in this chart, except when specifically noted.

[2] Information concerning Contract Term was taken from the pipeline's Index of Customers Report or as it is currently listed in the pipeline's FERC Gas Tariff. The contracts described herein may have been terminated or the Contract Term altered from as it is listed in the original contract or precedent agreement. Review of the actual contracts or precedent agreements between the producer and pipeline was limited, as they are typically treated as confidential and not made available to the public. *See, e.g.*, 18 C.F.R. § 388.112.

[3] Transportation Service Agreement, Rate Schedule FT, between Cheyenne Plains Gas Pipeline Co. and BP Energy Co., as contained in Cheyenne Plains Gas Pipeline Company's Implementation of Tariff filing , FERC Docket No. CP03-302-004 (filed Sept. 23, 2004). Much of this information is also included in Cheyenne Plains' most recent Index of Customers Report form January 2007.

[4] Information derived from the Original FERC Gas Tariff included with the Rockies Express Pipeline certificate application filed on May 31, 2006, in FERC Docket CP06-354-000. Rockies Express Pipeline, FERC Gas Tariff, Pro Forma Second Revised Volume No. 1, Original Sheet Nos. 8-9A. As noted in the chart, the contract does not become effective until January 2008.

[5] BP Energy Company's commitment on the Rockies Express Pipeline will increase to 300,000 Dth/day as of the in-service date of the REX-East portion of the pipeline. This agreement to ramp up its capacity resulted in BP being classified as an Anchor Shipper on the Rockies Express system. *See* Rockies Express Pipeline LLC, Certificate Application, Vol. 1, Docket No. CP06-354-000, page 51 (filed May 31, 2006).

[6] Gas Transportation Agreement between Tennessee Gas Pipeline Company and BP Energy Company, included in Negotiated Rate Tariff filing, FERC Docket No. RP96-312-072 (filed May 30, 2002). Information also contained in TGP's 1/1/07 Index of Customers.

[7] Transwestern Pipeline Company, FERC Gas Tariff, Third Revised Volume No. 1, First Revised Sheet Nos. 6-7, Second Revised Sheet Nos. 8-13.

[8] Transwestern Pipeline Company, FERC Gas Tariff, Third Revised Volume No. 1, First Revised Sheet Nos. 6-7, Second Revised Sheet Nos. 8-13.

[9] Transwestern Pipeline Company, FERC Gas Tariff, Third Revised Volume No. 1, First Revised Sheet Nos. 6-7, Second Revised Sheet Nos. 8-13.

[10] Alliance Pipeline L.P., FERC Gas Tariff, Original Volume No. 1, Twelfth Revised Sheet No. 11, Sixth Revised Sheet No. 12-14.

[11] Alliance Pipeline L.P., FERC Gas Tariff, Original Volume No. 1, Twelfth Revised Sheet No. 11, Sixth Revised Sheet Nos. 12-14.

[12] Alliance Pipeline L.P., FERC Gas Tariff, Original Volume No. 1, Twelfth Revised Sheet No. 11, Sixth Revised Sheet Nos. 12-14.

[13] Questar Pipeline Company, FERC Gas Tariff, First Revised Volume No. 1, Fortieth Revised Sheet No. 7, Twelfth Revised Sheet No. 7A.

[14] Information derived from the Original FERC Gas Tariff included with the Rockies Express Pipeline certificate application filed on May 31, 2006, in FERC Docket CP06-354-000. Rockies Express Pipeline, FERC Gas Tariff, Pro Forma Second Revised Volume No. 1, Original Sheet Nos. 8-9A. As noted in the chart, this contract does not become effective until January of 2008.

[15] Transwestern Pipeline Company, FERC Gas Tariff, Third Revised Volume No. 1, First Revised Sheet Nos. 6-7, Second Revised Sheet Nos. 8-13.

[16] Transwestern Pipeline Company, FERC Gas Tariff, Third Revised Volume No. 1, First Revised Sheet Nos. 6-7, Second Revised Sheet Nos. 8-13.

[17] Alliance Pipeline L.P., FERC Gas Tariff, Original Volume No. 1, Twelfth Revised Sheet No. 11, Sixth Revised Sheet Nos. 12-14.

[18] Because Mobil's contract on Mojave predated the advent of FERC's "negotiated rate" policy, the rate for Mobil on Mojave was more accurately described as a discounted rate and was subject to escalation up to the maximum recourse rate (with special "banking provisions"). Mobil's rate cap was approximately $0.30 prior to full in-service, but increased to $0.35/MMBtu (subject to the pipeline's maximum recourse rate) once the pipeline was fully in-service. Historical contract information derived from Mojave Pipeline Company Index of Customers Report for the quarter ending April 1, 1996. Other information obtained from *Mojave Pipeline Co.*, 56 FERC ¶ 61,282, at 61,099 and 61,102 (1990). *See also Kern River Gas Transmission Co.*, 50 FERC ¶ 61,069, at 61,152 (1990).

Appendix B

Greenberg Traurig

PRIVILEGED AND CONFIDENTIAL ATTORNEY/CLIENT COMMUNICATION AND ATTORNEY WORK PRODUCT

Memorandum

TO: Donald C. Shepler
FROM: Kenneth M. Minesinger
DATE: March 12, 2007
RE: Cost Overruns

Introduction and Summary of Conclusions

This memorandum responds to a question posed yesterday by the State about responsibility for cost overruns on major pipeline construction projects. The question is whether, as suggested by the three major producers (Exxon, BP and Conoco, hereinafter the "Producers"), shippers would be expected to bear the risk of any cost overruns that occur in constructing an Alaska natural gas pipeline, if the project were constructed by an independent pipeline company instead of by the Producers. Specifically, the Producers have suggested that the initial shippers will bear all of the project risk, including the risk of cost overruns, and that an independent pipeline company is 100 percent indifferent regarding project cost. In other words, cost overruns mean nothing to the pipeline because they are passed through completely to the shipper.

As discussed below, the short answer is that, while we of course cannot predict with certainty the precise terms of the contracts that ultimately will be agreed to between an Alaska pipeline and its shippers, it is clear that the Producers' assertion regarding pipeline indifference to cost overruns does not reflect Federal Energy Regulatory Commission ("FERC") policy. FERC strongly encourages pipelines to negotiate agreements with their shippers allocating the risk of cost overruns for major construction projects. There are a number of examples where pipelines and

shippers have negotiated fixed rate contracts, which allocate the risk of cost overruns above a rate cap to the pipeline, thereby insulating the shippers from the risk of cost overruns above the agreed-upon rate cap. Several of those examples are discussed below.

Introduction and Summary of Conclusions

In the Commission's 1999 *Policy Statement Concerning Certification of New Interstate Natural Gas Pipeline Facilities*, 88 FERC ¶ 61,227 (1999), *order on clarification*, 90 FERC ¶ 61,128 (2000), *order granting further clarification*, 92 FERC ¶ 61,094 (2000), the Commission encouraged pipelines to negotiate risk sharing agreements with shippers participating in a new project regarding the rate impact of cost overruns (and underutilized capacity). The Commission stated:

> [T]he risks of construction cost overruns should not be the responsibility of the pipeline's existing customers but should be apportioned between the pipeline and the new customers in their service contracts. Thus, in pipeline contracts for service on newly constructed facilities, pipelines should not rely on standard "Memphis clauses", but should reach agreement with new shippers concerning who will bear the risks of underutilization of capacity and cost overruns and the rate treatment for "cheap expansibility."[1]

Although this statement was made in the context of an expansion of an existing pipeline in connection with FERC's policy of protecting existing shippers from cost overruns, subsequent cases have cited the same principle in the concept of new, "greenfield" pipelines.

Consistent with the 1999 Certificate Policy Statement, the clear trend in recent years has been for pipelines and shippers to enter into negotiated rate agreements that allocate the risk of cost overruns for major construction projects, including new pipelines and pipeline expansions. Very

[1] 88 FERC ¶ 61,128, at 61,747 (emphasis added). A "Memphis clause" refers to contractual provision that permits the pipeline to change the rate during the term of the contract by making rate filings under Section 4 of the Natural Gas Act.

recently, in its December 2006 order certificating the Millenium pipeline project, a new pipeline project serving the Northeast U.S., FERC addressed this precise issue. *Millenium Pipeline Co.*, LLC, 117 FERC ¶ 61,319 (2006). There, FERC approved an agreement between Millenium and its shippers that allocated the risk of cost overruns above an agreed-upon rate cap to Millenium -- not to the shippers. FERC stated:

> In the Certificate Policy Statement, we urged pipelines and project customers to use their business expertise and negotiating skills to apportion the risks of construction cost overruns in their service contracts, noting that the parties are in the best position to allocate such risks at the time of contracting, rather than leaving such issues for litigation at the Commission.
>
> Millennium has addressed the issue of cost overruns, with Millennium and its shippers agreeing to rate caps over a ten-year term as set forth in an amendment to section 3 of the *pro forma* firm transportation service agreements. To the extent the negotiated rate methodology would yield a rate above the cap due to project cost overruns, Millennium will bear the cost of such overruns. When Millennium files its statement on construction costs within six months after the facilities are constructed in compliance with section 157.20(c)(3) of the regulations, Millennium will be required to compare the projected construction costs to the actual costs and explain any significant differences. Thus, we find that Millennium has adequately addressed the issue of cost overruns.[2]

Later, in the same order, FERC found that a second pipeline (Iroquois), which was also constructing new facilities in association with Millenium's project, had also agreed to bear the risk of cost overruns:

> We find that Iroquois and Consolidated Edison have addressed the issue of cost overruns in their negotiated rate agreement, since the agreement provides for a rate cap for the firm transportation service tied to the cost of the new facilities, which protects Iroquois' other customers from cost overruns. Further, if the facilities exceed a given cost, the rate charged to Consolidated Edison will not go

[2] *Id.* at PP 110, 111 (footnotes omitted).

above the cost specified in the negotiated rate agreement and Iroquois will bear the cost of the overruns.[3]

The Millennium and Iroquois projects are by no means the only examples where the risk of cost overruns on a major pipeline construction project has been allocated to the pipeline. The issue of cost overruns is not an issue which FERC has been required to address in a large number of orders regarding new construction projects. We have, however, researched the negotiated rate filings for several major new construction projects, and have found several instances where pipelines have agreed to negotiated, fixed rates that effectively allocate the risk of cost overruns above a rate cap to the pipeline. Examples include: (1) Cheyenne Plains, which involved the construction of a major new pipeline connecting Rockies gas supplies with Mid-Continent pipelines; (2) Rockies Express, a major new pipeline which will connect Rockies gas supplies to pipelines in the Mideast U.S.; (3) Gulfstream, a major pipeline serving Florida, constructed in the

[3] *Id.* at P 112 (footnotes omitted). *See also Empire State Pipeline*, 116 FERC ¶ 61,074, at P 116 (2006) ("We believe that the potential exists for cost overruns here because the pipeline facilities are to be constructed more than two years after the filing date. We addressed this issue in the Certificate Policy Statement, finding that pipelines should reach an agreement with their new shippers concerning who will bear the risk of cost overruns. The Certificate Policy Statement found that the responsibility for cost overruns should be apportioned between the pipeline and the new customers that have subscribed for the new capacity, so that the overruns will not become the responsibility of the existing shippers. EPI admits that its agreement with KeySpan does not contain this risk-sharing provision. In the application, however, EPI reserves the right to revise its initial rates prior to the commencement of service to reflect the changes in construction costs, unless the parties agree otherwise. If EPI seeks to change the proposed rates prior to placing the facilities into service, it must file a section 7(c) amendment to this filing. If EPI seeks a change after the facilities are placed into service, we will require EPI to make a section 4 rate filing.") (footnotes omitted); *Iroquois Gas Transmission System, L.P.*, 100 FERC ¶ 61,275, P 35 (2002) ("Under the Policy Statement, the Commission urges pipelines and project customers to apportion the risks of construction cost overruns in their service contracts. While the contracts between Iroquois and each ELI Project shipper do not currently contain the cost sharing language encouraged by the Policy Statement, Iroquois indicates that it intends to finalize its contracts with the ELI Project shippers on either January 1, 2003 or March 1, 2003, depending on the shipper. It states that at that time it will enter into a mutually agreeable cost sharing structure with the shippers that will be in a manner consistent with the Policy Statement. The Commission strongly urges Iroquois and the ELI Project shippers to enter into a cost sharing agreement on cost overruns.") (citations omitted).

1990s; and (4) Guardian, a significant pipeline serving Wisconsin, also constructed in the 1990s.[4] We expect this list will grow after further research (which will also include an analysis of negotiated, fixed rate contracts held by the Producers themselves on Lower 48 pipelines).

Even before FERC's 1999 Certificate Policy Statement, and well before the advent of negotiated rates, pipelines sometimes agreed to bear the risk of cost overruns. For example, in the early 1990s, Mojave Pipeline Company and its shippers entered into firm contracts with fixed rate caps that allocated the risk of cost overruns to Mojave. *See Center Point Energy Gas Transmission Co.*, 112 FERC ¶ 61,223 (2005) (discussing how Mojave entered into risk sharing agreements with its initial shippers which " provided the shippers rate certainty by capping their rates at levels which could be less than Mojave's maximum rates, depending upon its actual cost of constructing the pipeline and its cost of operating the pipeline."); *see Mojave Pipeline Co.*, 57 FERC ¶ 61,300, at 61,958 (1991) ("Mojave states that these contract rate caps provide rate certainty and protect Mojave's customers from overruns in the cost of the construction of Mojave's pipeline, as well as excesses in the cost of operation, resulting in increases beyond negotiated levels.") (emphasis added).[5]

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[4] *See, e.g.*, Cheyenne Plains Gas Pipeline Company, LLC, FERC Gas Tariff, Original Volume No. 1, Effective Sheet Nos. 22 - 28A; Rockies Express Pipeline, LLC, FERC Gas Tariff, Original Volume No. 1, Effective Sheet Nos. 22 - 24; Gulfstream Natural Gas System, LLC, FERC Gas Tariff, Original Volume No. 1, Effective Sheet Nos. 8 - 8Z; Guardian Pipeline, LLC, FERC Gas Tariff, Original Volume No. 1, Seventh Revised Sheet No. 6.

[5] Although beyond the scope of this memorandum, it should be noted that, in addition to FERC's statements about allocating the risk of cost overruns, there may be other reasons why a pipeline would not be indifferent to the cost of constructing an Alaska pipeline. For example, even though it can be expected that only one pipeline will be built from Alaska to destination markets in Canada or the Lower 48 States, that pipeline will still be required to compete to some degree with other existing pipelines serving those same markets. While the level of pipeline competition in such markets may not be as robust as what one would see in a highly competitive market (thus, the continued need for regulation of natural gas pipelines), nevertheless the level of competition between pipelines has increased as a result of FERC regulatory initiatives over the past two decades. This would likely provide an independently-owned Alaska pipeline at

Conclusion

FERC has encouraged pipelines and shippers to allocate contractually the risk of cost overruns for new construction projects. The clear trend has been for pipelines to agree to negotiated, fixed rate contracts that allocate the risk of cost overruns above a rate cap to the pipeline. Assuming this form of contractual arrangement is used in Alaska, the suggestion by the Producers that an independently-owned Alaska pipeline would be indifferent to cost overruns is incorrect.

least some incentive to control costs, even in the absence of negotiated fixed rate contracts. This may be an issue which the State may wish to ask one of its economic consultants to analyze further, although based on our experience in the natural gas industry the development of increased competition among natural gas pipelines generally over the past twenty years cannot be disputed, particularly in certain parts of the U.S. A related issue is whether an independent pipeline, experienced in building pipeline projects, is better equipped than the Producers to construct an Alaska pipeline in a cost-efficient manner. That issue also is beyond the scope of this memorandum.

SB
104
(FILE 2)

ALASKA STATE LEGISLATURE

Sen. Charlie Huggins, Chair
Sen. Bert Stedman, Vice Chair
Sen. Lyda Green
Sen. Gary Stevens
Sen. Lesil McGuire
Sen. Bill Wielechowski
Sen. Thomas Wagoner

State Capitol, Room 119
Juneau AK 99801-1182
907-465-3878
Fax: 907-465-3265
800-862-3878

Senate Resources Committee

Butrovich Room 205

Friday, March 23, 2007

AGENDA

- **SB 104 – Natural Gas Pipeline Project**
  "An Act relating to the Alaska Gasline Inducement Act; establishing the Alaska Gasline Inducement Act matching contribution fund; providing for an Alaska Gasline Inducement Act coordinator; making conforming amendments; and providing for an effective date."

1:30-5:30

ExxonMobil US
Martin W. Massey, Joint Interest Manager

Anadarko
Mark Hanley, Public Affairs Manager

BP
David Van Tuyl, Commercial Manager Alaska Gas

ConocoPhillips
Wendy King, Director, State Negotiations

AGIA Testimony

INTRODUCTION

Good morning Senator Huggins and members of the Senate Resources Committee. My name is Marty Massey. I am the U.S. Joint Interest Manager for ExxonMobil, a position I have held since November 2001, and I am responsible for the commercialization of ExxonMobil's gas resources in Alaska

ExxonMobil has been in Alaska for over 50 years and has been a key player in Alaska's oil industry development. We hold the largest working interest at Prudhoe Bay (36.4%) and our current net production in Alaska is approximately 150,000 barrels of hydrocarbons per day.

We have benefited from our involvement in the State of Alaska, and we believe that Alaska has benefited from this long-term relationship as well. Commercializing Alaska's North Slope gas will allow us to continue this relationship for another 50 years or more.

EXXONMOBIL READY TO PROGRESS PROJECT

With that introduction, I would like take a moment to emphasize the importance of the Alaska Gas Pipeline project to Alaska, to ExxonMobil, and to our nation. The Project has the potential to generate billions of dollars in revenues for the State of Alaska, the U.S. federal government, and Canada, and could provide a stable and secure source of clean energy for Alaska and North America for decades to come. ExxonMobil supports efforts to advance a pipeline project and we are ready to work with Governor Palin and her cabinet and with the Legislature to move forward the Alaska gas pipeline project.

Let me demonstrate the importance of this project to ExxonMobil. It has the potential to add over 1 billion cubic feet per day (EM share) of gas sales, which would be more than a 10% increase to our current worldwide daily gas production. Given the significant impact this project could have on our business, we are obviously very interested in progressing it.

As an illustration of our commitment, EM has spent more than $180 million studying ways to commercialize Alaska gas. Since the 1970's we have evaluated LNG, gas to liquids and gas pipeline alternatives. Based on these studies we have determined that a Producer gas pipeline project will result in the best value for the State, the Producers and the nation. It is important for me to say ExxonMobil is aligned with the Governor, the legislature and the people of Alaska regarding the overall objective—we are committed to moving the Alaska Gas pipeline project forward.

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PROJECT RISK / PRODUCER CAPABILITIES

Because there is a perception this is "simply" a gas treating / gas pipeline project, the tendency exists for many to underestimate the size, magnitude and risks associated with this undertaking. The Alaska Gas Pipeline Project is a world-scale undertaking with significant risks. In fact, the Project would be the largest private investment in North America – significantly larger than most "model" worldwide oil and gas "mega" projects. There is not really another project that compares.

Because of this size, many factors impact commercial viability.

First there is cost:

Our previous estimate of $20 billion ($2001) is now substantially higher. Since 2001, steel prices have nearly doubled. Industry and construction labor costs are experiencing hyperinflation. In addition, world-wide mega-projects are placing pressure on pricing and availability of global materials, and skilled manpower.

Next there is gas price:

Despite recent increases, natural gas prices remain highly volatile. The price of natural gas before 2000 was less than currently estimated gas treating and transportation costs.

Finally, there are many other risks.

These include cost overruns, schedule delays, construction conditions, and regulatory and State fiscal uncertainties. It is also important to note that project investments would have to be made 10 or more years before gas flows down the pipeline and is sold at the marketplace.

With size comes complexity, and an even greater premium on getting the design concept, contracting and marketing plans right...and then executing these plans efficiently and effectively. Most importantly, size also amplifies the consequences of poor execution. If a mistake is made on this project it would cost us all dearly.

HOW PIPELINES ARE FINANCED AND WHO BEARS PROJECT RISKS

Let me now make a few comments on how projects are financed and who bears the risks. Commercially-sound oil, gas, and pipeline projects traditionally have been able to obtain financing if they have strong sponsors with proven track records and the financial strength to both provide sponsor equity and to backstop key project commitments. For the Alaska gas pipeline project, key project commitments take the form of firm, long-term gas transportation commitments. Firm transportation commitments (often abbreviated and called FT) are binding obligations made by companies (known as "shippers") to pay for the cost of reserving a quantity of gas capacity on a pipeline over a specified period of time, typically many years. These commitments are made during an "open season", which, according to FERC Order 2005 for the Alaska gas pipeline, is a period of at least 90 days during which any and all prospective gas shippers can make binding commitments for a specific volume of transportation capacity.

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Financial institutions generally require substantial, long-term, firm transportation commitments to provide funding for a gas pipeline project. These commitments must be provided by creditworthy shippers. In this case, the shippers will be the Producers, and, directly or indirectly, the State or the State's shipper. These firm transportation commitments are substantial, in the tens of billions of dollars and must be paid whether the shipper making those commitments actually transports gas through its reserved transportation capacity. The shipper is also required to pay this commitment regardless of the price of gas in the market place.

Pipeline investors use these firm transportation commitments from shippers to show creditors they have capacity confirmed over a sufficient duration to secure financing and must rely on the financial strength of the companies backing the transportation commitments to secure project financing. Thus, the development costs and the associated over-run risk are ultimately borne by the shipper via this commitment. In other words, shippers must make long-term ship or pay transportation commitments and agree to pay transportation and treating rates that are based on the ultimate cost of the pipeline and treating facilities. The only information known in advance of making these commitments will be a projection based on each project entity's initial estimate of costs.

For that reason, the parties taking the risks need to be able to manage those risks. The Producers, as shippers, cannot make firm transportation commitments during an open season unless they are confident the gas pipeline project can be built cost effectively and operated on a long-term, commercially viable basis, including being competitive with other sources of gas supply. This is especially true for a project of this magnitude.

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

Maximizing the value to the State of Alaska and the resource holders means selecting the right design concept for this mega-project and then executing the project to deliver the lowest possible cost.

On a mega-project of this size and magnitude, project construction and operating experience should be a significant consideration. Only a limited number of companies have demonstrated the capabilities and financial strength to effectively participate in and manage world-scale mega-projects.

The Producers have mega-project experience on numerous projects world-wide and have demonstrated success in meeting project objectives. For example, ExxonMobil operates in nearly 200 countries and territories and on every continent except Antarctica. We are the world's largest non-government producer of both oil and natural gas. ExxonMobil's global project development company is unique within industry. This global development company leads the industry in project cost and schedule performance. Over time, development costs are 25% lower than industry average on a $/barrel basis. Nearly 90% of ExxonMobil projects with costs greater than $1 billion are delivered within 15% of estimated costs at the time of project funding and nearly 80% of those were delivered within 15% of the funding schedule. ExxonMobil's superior performance was independently validated in a report (dated September 21, 2005)

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published by Sanford C. Bernstein and Co. On the topic of project delays, the report stated "ExxonMobil came out on top of this analysis, with the lowest slippage rates, despite undertaking some of the largest projects. We believe this to be a direct result of its highly competent internal development company, which assumes full responsibility for monitoring a new project from idea to profit." Combining our capability with BP and ConocoPhillips will provide the best chance of delivering a successful project.

The Producers also have Arctic experience in Alaska and throughout the world. ExxonMobil's arctic experience is extensive - over 40 years – with developments in multiple types of arctic environments. Our Arctic offshore activity started in 1968 with the installation of the ice resistant Granite Point platform in Alaska's Cook Inlet, which is still producing oil. In the 1970's we provided a significant amount of research and engineering for the Prudhoe Bay project, where our completion designs for permafrost were of key importance to the project. We also developed the combined hydraulic flow model and thermal simulator on which the design of TAPS was based. In 1984, we installed the Concrete Island Drilling System (CIDS) to drill exploration wells in the Alaska Beaufort Sea. This was the first mobile drilling platform to operate in the ice covered waters of the Beaufort. In addition to our Arctic experience in Alaska, ExxonMobil also has extensive Arctic experience in Canada, developing the Norman Wells Field in the Mackenzie River area near the Arctic Circle. Offshore Newfoundland, we completed the Hibernia platform, the first and only iceberg resistant offshore structure in the world. In Russia, we recently started up the Sakhalin 1 development which involved an offshore drilling platform where CIDS was reused and renamed Orlan, an onshore drillsite where we have set new industry limits for extended reach drilling, an onshore oil and gas plant with a capacity of 250,000 barrels per day, and purpose built tankers which are used year-round. All of this work is being done in an arctic and seismically-active area. At Sakhalin we are currently producing 250,000 barrels of oil per day.. I hope you see from these examples that large projects with significant complexity are what we do and we are extremely qualified to take on this work.

These successful efforts were the result of a long-term commitment to technology development which has played an important role in the advancement of oil and gas development in Alaska. ExxonMobil believes innovation is the key to meeting the world's energy challenges. Technology is the lifeblood of our industry, and it always has been. We are the leader in our industry in technology development. In 2006, we spent $730 million on technology development and we have spent more than $3 billion since 2002.

In addition, ExxonMobil has demonstrated world-class leadership in safety, health and environmental performance. ExxonMobil is a leader in operating efficiency and a pacesetter in operating safety. Our total recordable incident rates for employees and contractors are substantially below the average of US Petroleum Industry benchmark of participating American Petroleum Institute companies. We believe a company's commitment to the highest standards of safety, health and environmental care manifests itself in superior performance in all aspects of its operations.

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