UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Gas Transmission Northwest Corporation) Docket Nos. RP06- -000

Prepared Direct Testimony of Steven H. Levine

I. INTRODUCTION AND SUMMARY

Q: Please state your name, address, and position.

A: My name is Steven H. Levine. I am a Principal of The Brattle Group, an economic and management consulting firm with offices in Cambridge, MA, Washington DC, San Francisco, CA, London, England, and Brussels, Belgium. My office is located at 44 Brattle Street, Cambridge, Massachusetts 02138.

Q: What are your educational background and professional qualifications?

A: I have over 10 years of experience consulting to firms in the natural gas industry. My work in the natural gas industry has focused on financial modeling, valuation, ratemaking, damages estimation, regulatory economics, analysis of competition, and business strategy. I have been involved in several proceedings that have evaluated the structure of the California natural gas markets, including the merger proceedings between the parent companies of Southern California Gas Company and San Diego Gas & Electric before both the Federal Energy Regulatory Commission ("FERC" or "the Commission") and before the California Public Utilities Commission ("CPUC"), the California gas market restructuring proceeding before the CPUC, and the CPUC's complaint against El Paso Natural Gas before the FERC. I also testified before the CPUC during its investigation of the causes of the natural gas price spikes at the California border during 2000-2001. I hold an M.B.A. in finance from Columbia Business School and a B.A. in economics from Brandeis University. My background, publications, and prior testimony are described in my resume, which is included as Exhibit No. GTN-43.

Q: What is the purpose of your testimony in this proceeding?

A: I have been asked by Gas Transmission Northwest Corporation ("GTN") to review the business risks of GTN and evaluate how GTN's business risks compare to those of a proxy group of other U.S. gas pipelines that are also regulated by the Commission.

Q: What are your conclusions?

A: I conclude that GTN has well above-average business risk relative to the pipeline proxy group that I have selected. GTN faces well above-average supply risk due to its heavy dependence on gas supplies that are sourced from the Western Canadian Sedimentary Basin ("WCSB"), a basin where production appears to have plateaued and is projected to remain flat or decline in the coming years. In addition, GTN faces substantial competition for WCSB supplies, which are also transported to markets in the U.S. Midwest and Northeast. Those markets have offered better netbacks in recent periods, making GTN a less attractive choice for uncommitted WCSB gas supplies.

GTN also faces above-average market risk in its primary destination market in California. WCSB gas supplies transported to California via GTN compete with Rocky Mountain gas supplies transported to California via Kern River Pipeline Company and Southwest gas supplies transported by El Paso Natural Gas Company, Transwestern Pipeline Company, and Questar Southern Trails Pipeline. Since 2001, there have been several expansions of pipeline capacity to California, which have resulted in excess interstate pipeline capacity to the state.

As a result of the competitive conditions in GTN's supply and market areas, GTN's pipeline capacity has been devalued significantly. Specifically, relatively high prices in GTN's supply area and relatively low prices in GTN's market area have reduced the value of the pipeline corridor from the WCSB to California, including GTN's portion of the corridor from Kingsgate to Malin. GTN Witness Leslie Ferron-Jones describes how GTN has had difficulty selling its unsubscribed capacity at discounted rates due to these conditions. Moreover, GTN faces new competition from the entry of LNG in Baja California, Mexico. Specifically, Sempra Energy's Costa Azul LNG terminal is under construction and expected to become operational in 2008, providing new competition for GTN in the northern and southern California markets that GTN serves.

GTN is exposed to these changing market conditions due to recent and future contract expirations. GTN's largest customer, Pacific Gas & Electric ("PG&E") is currently a year-to-year transportation customer that has been extending its contract for one-year periods under the evergreen provisions of its contract. However, PG&E appears to be positioning itself to access new LNG supplies, making its commitment to pipeline capacity on GTN tenuous and significantly increasing GTN's business risk.

Q: How is your testimony organized?

A: In section II, I describe the nature of a pipeline's business risk, and specify the factors the Commission should consider in evaluating a pipeline's business risk. I also identify the pipelines in the proxy group that I use in my assessment of GTN's relative business risk.

In section III, I evaluate GTN's supply risk relative to the supply risk of the proxy group. In section IV, I examine GTN's market risks relative to the market risks of the proxy group. In section V, I evaluate GTN's contract profile relative to the proxy group.

II. FRAMEWORK FOR ANALYZING BUSINESS RISK

Q: What is business risk in the context of a regulated gas pipeline?

A: Business risk refers to the uncertainty in a pipeline's future cash flows that primarily results from the contractual and throughput uncertainty to which the pipeline is exposed. Pipeline investments typically entail large capital commitments that are sunk costs after they have been made. Since pipeline assets are not easily redeployed after they are constructed, pipelines attempt to create revenue certainty by entering into long-term contracts for capacity that in aggregate recover depreciation expenses, operating and maintenance costs, taxes, and a fair return on capital. In the absence of such long-term contracts, a pipeline's cash flows are exposed to uncertainty. An evaluation of a pipeline's business risk reviews the factors that create uncertainty in the pipeline's cash flows, including changing market conditions that may reduce the market value of (or level of demand for) the pipeline's capacity.

Q: How does the Commission use evidence concerning a pipeline's business risk?

A: The Commission considers evidence on business risk as part of its determination of a pipeline's allowed return on equity ("ROE"). Specifically, the Commission examines the ROE range suggested by a proxy group of publicly-traded companies, and then assigns the subject pipeline a return within this range based on its relative risk position. Although I am aware that the Commission has indicated that it will consider factors specific to the pipeline's markets in determining a pipeline's placement within the ROE range, I do not believe the Commission has articulated a standard set of criteria for evaluating the business risk of a pipeline.[1] Accordingly, I discuss below the factors that I believe the Commission should consider in performing such an evaluation.

Q: What factors should the Commission consider in analyzing a pipeline's relative business risk?

A: The Commission should review the market conditions and competitive forces faced by the pipeline in both its origin and destination markets. For example, the Commission should consider gas supply conditions in the pipeline's origin markets, including forecasts of gas production in the supply area, the ability of competing pipelines to access those supplies, and the diversity of supplies accessed by the pipeline.

The Commission should also consider the destination markets served by the pipeline, including the degree of competition in the market area. A pipeline that faces less competition in its market area will tend to have lower risk than a pipeline that faces substantial competition. This competition can include alternative pipeline transportation routes to the market area (from either the same supply basin or from different supply basins). It can also include new pipelines that access new sources of supply (*i.e.*, new supply basins or new LNG import terminals). The Commission should also consider factors that adversely affect the value of the pipeline's capacity, such as over-capacity conditions in a destination market that may diminish the value of regional pipeline capacity.

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[1] *See*, for example, the Commission's Opinion No. 414-A (84 FERC 61,084 (July 29, 1998)) in which the Commission noted it "will focus on the risks faced by the pipeline that are attributable to circumstances outside the control of the pipeline's management, such as factors specific to the pipeline's markets, which would include the degree and effectiveness of competition in the markets."

Q: Are there other factors that the Commission should consider in evaluating a pipeline's business risk?

A: Yes. The Commission should also consider the strength of the pipeline's contractual status. For example, a pipeline that is fully subscribed with long-term contracts will tend to have low business risk due to the resulting cash flow stability. Another factor is the credit quality of the shippers that hold a pipeline's capacity. In general, a pipeline with high credit quality shippers has lower risk than a pipeline with low credit quality shippers because the latter faces higher exposure to shipper default or bankruptcy (which can adversely affect the pipeline's cash flows).

Q: What pipelines do you use in your evaluation of GTN's relative business risk?

A: I compare GTN's business risk to a proxy group consisting of the major pipelines owned by the corporations that GTN Witness Paul R. Moul analyzes in his assessment of the appropriate return on equity for GTN. Specifically, the pipelines I consider are:

Equitrans: Owned by Equitable Resources, Equitrans transports gas from West Virginia to Western Pennsylvania (near Pittsburgh).

Natural Gas Pipeline Company of America ("NGPL"): Owned by Kinder Morgan, Inc., NGPL transports gas from the Gulf Coast, South Texas, Permian, and Mid-continent supply areas to Midwest U.S. markets. NGPL also transports gas from the WCSB via Northern Border.

National Fuel Gas Supply ("National Fuel"): Owned by National Fuel Gas Company, National Fuel transports gas in Western New York and Western Pennsylvania.

Questar Pipeline ("Questar"): Owned by Questar Corporation, Questar transports Rocky Mountain gas in Utah, Wyoming, and Colorado.

Transco: Owned by Williams, Transco transports gas from the Gulf Coast to the Southeast U.S., Mid-Atlantic, and New York.

Northwest: Owned by Williams, Northwest transports gas produced in western Canada, the Rocky Mountains, and San Juan Basin to markets in the Pacific Northwest.

El Paso Natural Gas ("EPNG"): Owned by El Paso Corporation, EPNG transports gas from Southwest U.S. producing basins to markets in Texas, New Mexico, Arizona, and California.

ANR: Owned by El Paso Corporation, ANR transports gas from Mid-Continent and Gulf Coast supply areas to markets in the U.S. Midwest.

Southern Natural: Owned by El Paso Corporation, Southern Natural transports gas from the Gulf Coast and Elba Island LNG import terminal in Georgia to markets in the U.S. Southeast.

Tennessee Gas Pipeline: Owned by El Paso Corporation, Tennessee transports Gulf Coast and WCSB gas supplies to the Midwest, Mid-Atlantic and Northeast.

III. SUPPLY RISK

Q: What is supply risk?

A: Supply risk refers to the risk that gas supplies will not be available in sufficient quantities for transportation on a pipeline. For example, supply risk can result from declining production in a specific supply basin, especially if the pipeline relies heavily on one production basin rather than having direct access to diverse gas supplies. Or, supply risk can result from competition for supply from competing pipelines.

Q: Where is gas transported by GTN produced?

A: Roughly 92% of the gas that is transported on GTN is sourced from the WCSB.[2] GTN accesses WCSB supplies through an interconnection with TransCanada's British Columbia system at the U.S.-Canadian border at Kingsgate. The British Columbia system in turn accesses WCSB supplies through an interconnection with TransCanada's Alberta system. The remaining 8 percent of volumes that flow on the GTN system are delivered via Northwest pipeline (at Stanfield, Oregon), which accesses Canadian supplies at Sumas and Rocky Mountain supplies. GTN itself does not directly access Rocky Mountain supplies.

Q: What is the supply outlook for the WCSB?

A: After a long period of increasing production during the 1990s, many forecasters now believe that the WCSB has plateaued and will remain flat or decline in the coming years. For example, a September 2003 study by the National Petroleum Council ("NPC") found:

> The WCSB is mature and its production has plateaued. The remaining undiscovered conventional resource (93 TCF) is located

[2] Prepared Direct Testimony of GTN Witness Leslie Ferron-Jones, Exhibit No. GTN-26 at p. 6.

> in increasingly smaller average pool sizes. Nonconventional resources are not as well assessed as in the United States and have a large uncertainty range.[3]

The NPC 2003 study forecasted a decline in WCSB production from roughly 5.3 Tcf/year (14.5 Bcf/d) in 2005 to roughly 4.1 Tcf/year (11.2 Bcf/d) in 2025.[4] GTN Witness Walter W. Haessel describes the supply outlook for the WCSB in greater detail in his testimony.

Q: What is your assessment of GTN's supply risk?

A: GTN faces well above-average supply risk due to the forecasted flat or declining production profile of the WCSB and GTN's heavy dependence on this supply area. GTN's supply risks are exacerbated by growing demand for natural gas in Canada and competition for supplies in the WCSB on competing pipelines.

Q: How does growing gas demand in Canada increase GTN's supply risk?

A: Growth in gas demand in Canada reduces the amount of WCSB gas supplies available for export to U.S. markets, including the Pacific Northwest and California markets that GTN serves. GTN Witness Haessel describes forecasted growth in Canadian gas demand in more detail. However, I note here that the combination of production declines in the WCSB and growing gas demand in Canada appear to have caused the U.S. Energy Information Administration ("EIA") to forecast significant declines in U.S. imports of natural gas from Canada. As shown in Figure 1, EIA's 2006 Annual Energy Outlook forecasts a decline in U.S. imports from Canada from 3.2 Tcf (8.8 Bcf/d) in 2004 to 1.5

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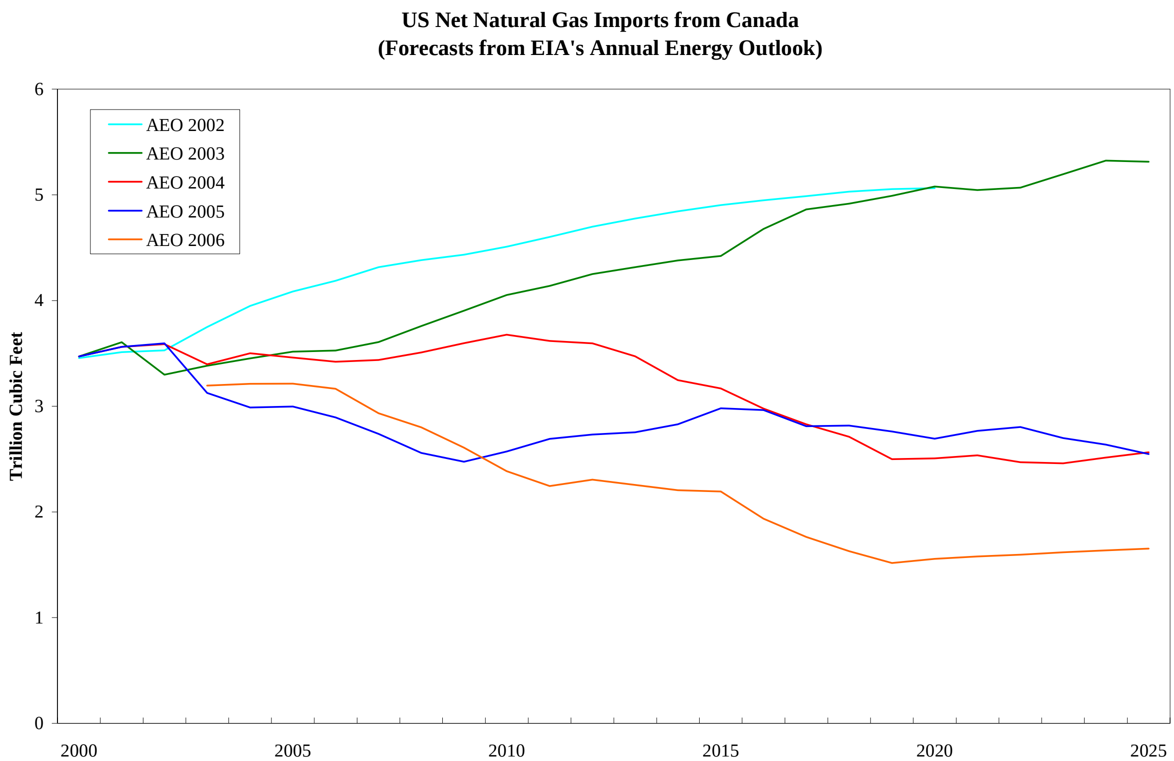
3 "Balancing Natural Gas Policy: Fueling the Demands of a Growing Economy," National Petroleum Council, September 2003, Volume IV (Supply Task Group Report), pp. 2-7.

4 *Id*., p. 2-20 (Figure S2-21).

Tcf (4.1 Bcf/d) in 2019. Figure 1 also shows the declining pattern of EIA's forecasts of imports from Canada in recent years.

Figure 1



Source: Energy Information Administration.

Q: Is the supply risk of the WCSB mitigated by new pipeline projects such as the Mackenzie Valley pipeline?

A: The Mackenzie Valley pipeline does not appear to significantly mitigate the production declines forecasted in the WCSB. The Mackenzie Valley pipeline is a proposed pipeline that would transport 1.2 Bcf/d of natural gas from the Mackenzie Delta in Canada's Northwest Territories to TransCanada's Alberta system. However, the EIA's 2006 Annual Energy Outlook's forecast of significant declines in U.S. imports from Canada (plotted in Figure 1 above) assumes entry of the Mackenzie Valley pipeline in 2011:

> A decline in Canada's non-Arctic conventional natural gas production is only partially offset by its Arctic and unconventional production. Although a MacKenzie Delta natural gas pipeline is expected to begin transporting natural gas in 2011 in the reference case, net imports from Canada fall from 3.2 trillion cubic feet [8.8 Bcf/d] in 2004 to 1.5 trillion cubic feet in [4.1 Bcf/d] in 2019. After 2019, net imports from Canada begin to increase, as unconventional production eventually offsets the decline in conventional production. Net imports of natural gas from Canada total 1.8 trillion cubic feet in 2030.[5]

One reason for this lack of mitigation is the potential demand for this new gas supply in Canada. In particular, EIA has explained how a portion of this gas is likely to be consumed in planned Canadian oil sands production activities, which would make that portion of the gas unavailable for export to the U.S.:

> While resources in the Delta are viewed as plentiful, the effect of the Mackenzie pipeline on natural gas supply to the United States is uncertain, with at least a portion of the incremental supplies likely dedicated to Canadian oil sands production, a process that requires large volumes of natural gas.[6]

Q: Please explain the competition GTN faces for supplies in the WCSB.

A: In addition to satisfying Canadian gas demand, gas produced in the WCSB can access several export markets in the Western, Midwest, and Northeast U.S. via several pipeline routes. WCSB gas supplies serve Western U.S. markets via GTN (and its interconnect with TransCanada's British Columbia system) and Northwest Pipeline (through its interconnect with Westcoast at Sumas). WCSB gas supplies serve Midwestern U.S. markets via Alliance pipeline, Northern Border (through its interconnection with Foothills at Monchy), Great Lakes Gas Transmission, and Viking Gas Pipeline (the latter two through interconnections with TransCanada's Mainline). Finally, WCSB gas

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[5] Annual Energy Outlook 2006, Energy Information Administration, p. 86.
[6] U.S. Natural Gas Imports and Exports: 2004, Energy Information Administration, December 2005, p. 4.

supplies serve Northeast U.S. markets via Iroquois Gas Transmission, Tennessee Gas Pipeline, and Empire Pipeline (which all interconnect with TransCanada's Mainline).[7]

Q: How does this competition for supplies increase supply risk to GTN?

A: As described by GTN Witness Ferron-Jones, there is currently excess pipeline capacity out of the WCSB.[8] In other words, there are not sufficient supplies of gas available to fill all the pipelines that access the WCSB. Moreover, as Ms. Ferron-Jones describes, WCSB gas supplies are transported to markets that have the highest netback. In recent periods, markets in the Northeast and Midwest have had more attractive netbacks than the Western markets served by GTN, which means that GTN is frequently the last transportation choice for uncommitted supplies.[9] If Northeast and Midwest markets continue to be the premium markets, this will tend to result in less throughput on GTN, and provide less incentive for parties to contract for capacity on GTN.

Q: What is your assessment of the supply risks faced by other pipelines in the proxy group?

A: Most of the pipelines do not face the same degree of supply risk that GTN faces. First, a few of the pipelines directly access the Rocky Mountain supply area, which is experiencing significant production growth, unlike the supplies in the WCSB. Pipelines that are connected to growing supply areas have lower risk, all else equal, than pipelines that are connected to declining supplies (since the former are more likely to remain fully utilized). Second, many of the pipelines in the proxy group depend on Gulf Coast gas

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[7] WCSB supplies also access Northeast markets through smaller interconnections with Vermont Gas, St. Lawrence Gas, and North Country Gas.

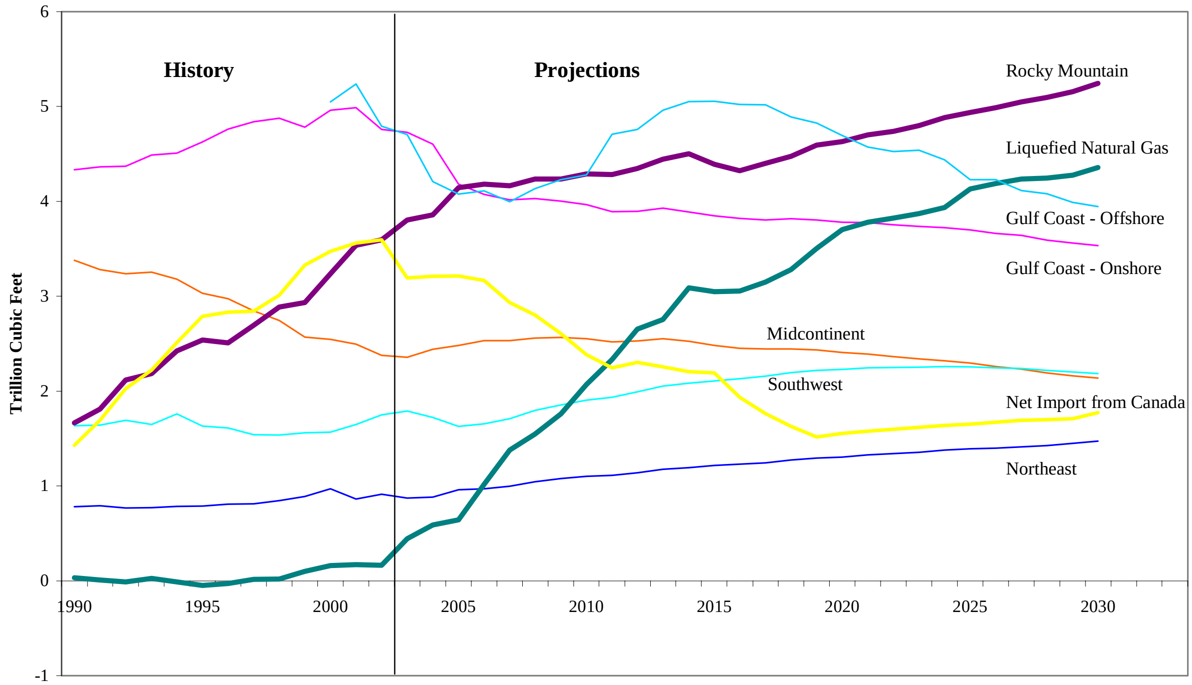
[8] Prepared Direct Testimony of GTN Witness Leslie Ferron-Jones, p. 8 (Exhibit No. GTN-26).

[9] *Id.*, p. 20 (Exhibit No. GTN-26). *See* also Prepared Direct Testimony of GTN Witness Paul R. Carpenter, Exhibit No. GTN-63, pp. 21-22 (Table 5).

supplies. As shown in Figure 2, EIA's 2006 Annual Energy Outlook contains a more favorable outlook for Gulf Coast supplies than it does for Canadian imports, which suggests lower supply risk for pipelines that depend on Gulf Coast supplies relative to a pipeline like GTN that depends heavily on Canadian supplies. Specifically, EIA's forecast for onshore Gulf Coast supplies does not decline as severely as its projection for Canadian imports and EIA projects growth in offshore Gulf Coast production between 2007-2015 before declining thereafter. Moreover, the supply risk of the Gulf Coast pipelines is mitigated by access to LNG supplies, which are also projected to be a growing source of gas supply for the United States. Third, several of the pipelines in the proxy group have direct access to multiple supply basins, which reduces risk relative to a pipeline like GTN, which depends so heavily on WCSB supplies.

Figure 2

Lower 48 Natural Gas Production by Supply Region and Net LNG Imports, 1990-2030



Sources: 1990-2002 EIA 2003 & 2005, Annual Energy Outlook,
2003-2030 EIA 2006, Annual Energy Outlook.

Q: Can you quantify the amount of growth that is expected from Rocky Mountain production and LNG imports?

A: Yes. Figure 2 shows the significant production growth in the Rocky Mountain supply area, as forecasted by EIA in its 2006 Annual Energy Outlook. As shown, EIA forecasts that the Rocky Mountain supply area will be the fastest-growing production area in the United States. Specifically, EIA forecasts that Rocky Mountain production will grow from roughly 3.8 Tcf/year (10.4 Bcf/d) in 2003 to 5.3 Tcf/year (14.4 Bcf/d) in 2030, an increase of nearly 40%. Figure 2 also shows EIA's forecast of growth in LNG imports, from 0.44 Tcf (1.2 Bcf/d) in 2003 to 4.36 Tcf (11.9 Bcf/d) in 2030.

Q: Which specific pipelines in the proxy group do you believe have lower supply risk than GTN?

A: Given that they are directly connected to the growing Rocky Mountain supply area, Questar and Northwest have relatively lower supply risk than GTN. Transco, NGPL, ANR, Southern Natural, and Tennessee also have lower supply risk given their access to Gulf Coast gas supplies. The supply risk of these Gulf Coast pipelines is also mitigated by the construction of several LNG import terminals in the Gulf Coast, which will rely on these pipelines for transportation of re-gasified LNG supplies. In fact, the Gulf Coast has become the location of choice for LNG developers, with LNG projects in the Gulf Coast advancing at a quicker pace than those in other locations in the United States. As EIA explained in a December 2005 report:

> The greatest number of proposed LNG terminal projects is slated for the Gulf of Mexico region. Nearly 20 LNG terminals are in various stages of planning, approval, construction, and operation on the U.S. Gulf Coast. Owing to extensive pipeline infrastructure through and out of the region, the Gulf region offers an opportunity for project sponsors to avoid some costs of new construction and take advantage of economies of scale. The projects include nine new projects that have been approved by FERC and MARAD . . .
>
> Of these approved projects, three have begun construction and several have plans to begin construction by year-end 2005.[10]

Moreover, Gulf Coast pipelines are starting to plan for increased LNG imports. For example, Transco recently announced an open season to provide customers access to growing LNG supplies. Transco's senior vice president recently explained the impetus for its open season:

> LNG is poised to become a much larger portion of our natural gas supply mix over the next several years. It is important that our

[10] U.S. Natural Gas Imports and Exports: 2004, Energy Information Administration, Office of Oil and Gas, December 2005, p. 10.

> Transco pipeline provide its customers with access to growing LNG and domestic supply options, particularly along the Gulf Coast . . . These pipeline projects represent Transco's unique solutions to ensure that its customers can take full advantage of these new supply alternatives . . .[11]

Likewise, Kinder Morgan has proposed the 137-mile, 3.2 Bcf/d Louisiana Pipeline to transport LNG supplies to NGPL, Tennessee, ANR, and others. Kinder Morgan's chairman described the need for the project:

> LNG is expected to be very important in meeting America's future energy needs and this project represents an exciting growth opportunity . . . Kinder Morgan's existing pipeline network, combined with our operating expertise, positions us well to provide needed infrastructure to transport regasified LNG to the marketplace.[12]

Q: How much LNG import terminal capacity is currently under construction in the Gulf Coast?

A: There is roughly 7 Bcf/d of incremental LNG import capacity currently under construction in the Gulf Coast.[13] Among the projects are 1) Sempra's Cameron LNG project near Hackberry, Louisiana (1.5 Bcf/d), 2) Cheniere Energy's Sabine Pass project in Sabine Pass, Louisiana (2.6 Bcf/d),[14] 3) Southern Union's Trunkline LNG expansion of its existing facility at Lake Charles, Louisiana (1.2 Bcf/d),[15] and 4) Freeport LNG in Freeport, Texas (1.5 Bcf/d).

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[11] Williams press release dated February 7, 2006. The press release provided details regarding the Production Area Mainline Expansion, which would "increase the company's ability to transport domestic supplies and imported liquefied natural gas from the Louisiana Gulf Coast area to aggregation centers along the Transco pipeline system . . . This proposed path-based expansion offers flexibility to shippers interested in accessing domestic supplies as well as supply from LNG import terminals currently under construction in southwest Louisiana."

[12] Kinder Morgan press release dated September 22, 2005.

[13] In addition, Excelerate Energy's Gulf Gateway deepwater LNG terminal went into service in 2005, with a capacity of 500 MMcf/d.

[14] In July 2005, Sabine Pass LNG filed to expand the terminal's capacity from 2.6 Bcf/d to 4 Bcf/d (CP05-396).

[15] Of this 1.2 Bcf/d, 570 MMcf/d went into service in April 2006, and the additional 600 MMcf/d was expected to be in service by mid-2006.

Some of these projects will provide supplies to pipelines in the proxy group. For example, Sempra's Cameron LNG project includes a proposed 35.4 mile pipeline that would interconnect with Transco in Beauregard Parish, Louisiana, and potentially interconnect with Tennessee Gas Pipeline, among others.[16] Likewise, Cheniere Energy's Sabine Pass LNG project includes a proposed pipeline that would interconnect with NGPL, and potentially interconnect with Transco and others.[17] Southern Union's Trunkline LNG expansion received FERC approval to increase metering capacity (to 500,000 Dth/d) at Trunkline Gas's existing delivery point with Transco, and to establish a new interconnection with Tennessee Gas Pipeline (metering capacity of 500,000 Dth/d).[18]

In addition, many other projects have been approved that would potentially provide LNG supplies to proxy group pipelines, including 1) Exxon's Vista del Sol project in San Patricio County, Texas (1.1 Bcf/d),[19] 2) Exxon's Golden Pass LNG project in Sabine Pass, Louisiana (1 Bcf/d),[20] 3) Cheniere Energy's Corpus Christi project in Texas (2.6 Bcf/d),[21] and 4) Occidental's Ingleside project in Texas (1 Bcf/d).[22] While it is not clear whether any of these projects will actually be constructed, if any of them are built they would provide additional capability for LNG imports beyond the capability that currently exists or is now under construction.

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[16] 101 FERC ¶ 61,294 (Docket No. CP02-374, December 18, 2002).
[17] 109 FERC ¶ 61,324 (Docket No. CP04-47, December 21, 2004).
[18] 108 FERC ¶ 61,251 (Docket No. CP04-64, September 17, 2004).
[19] 111 FERC ¶ 61,432 (Docket No. CP04-395, June 20, 2005). The FERC approved the associated Vista Pipeline, which has a proposed route that interconnects with Transco, NGPL, and Tennessee, among others.
[20] 112 FERC ¶ 61,041 (Docket No. CP04-386, July 6, 2005). The FERC approved the associated Golden Pass Pipeline, which planned to interconnect with Transco in Calcasieu Parish, Louisiana. Golden Pass Pipeline also envisioned up to 11 interconnections with existing pipelines.
[21] 111 FERC ¶ 61,081 (Docket No. CP04-37, April 18, 2005). The FERC approved the associated Cheniere Pipeline, which proposed to interconnect with Transco, NGPL, and Tennessee, among others.
[22] 112 FERC ¶ 61,101 (Docket No. CP05-13, July 22, 2005). The FERC approved the associated San Patricio Pipeline, which will potentially interconnect with Transco, NGPL, and Tennessee, among others.

Q: Do any of the proxy group pipelines have lower supply risk as a result of LNG terminals on the east coast of the United States?

A: Yes. Southern Natural and Transco are both well-positioned to transport LNG supplies from existing LNG terminals on the east coast. Southern Natural receives LNG supplies from the Elba Island LNG terminal, which is operated by Southern Natural's subsidiary Southern LNG.[23] Elba Island has proposed expansions of its LNG import terminal, and has also proposed the Elba Express Pipeline. Elba Express would interconnect with other pipelines, including Transco, to access markets in the southeast and eastern United States.[24] Transco also transports gas from Dominion's Cove Point LNG import terminal in Maryland.[25]

Q: Which pipelines in the proxy group have access to multiple supply areas?

A: NGPL has direct access to several gas supply areas, including gas supplies in Louisiana, South Texas, the Permian Basin, and the Mid-continent area. ANR has direct access to Gulf Coast and Mid-Continent supplies. This type of supply diversity lowers supply risk relative to a pipeline that has direct access to only one gas supply area. In addition, the supply risk of NGPL and ANR is mitigated by their potential ability to access LNG supplies in the Gulf Coast, as I discussed above.

Q: Are there any other pipelines in the proxy group that have lower supply risk than GTN?

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[23] Alabama Gas Corporation (Alagasco) entered into a 10-year gas purchase agreement with British Gas Services to purchase 30,000 MMBtu/d of LNG supplies at Elba Island for seven months of each year (October through April). Southern Natural delivers these supplies to Alagasco by displacement. *See* Alabama Gas Corporation's Response to Commission Staff Question 4 in Docket U-4708, dated January 23, 2006. Similarly, the Georgia Public Service Commission approved a proposal by Atlanta Gas Light for a two-year trial of LNG supply from Elba Island transported by Southern Natural segmented firm transportation capacity. *See* Amended Final Order and Order Denying Motions For Rehearing and Reconsideration dated October 19, 2004.

[24] El Paso press release dated December 21, 2005.

[25] FERC approved a 1 Bcf/d interconnection between Cove Point and Transco in Fairfax County, Virginia. *See* 97 ¶ FERC 61,043 (Docket Nos. CP01-76 and CP01-156, October 12, 2001).

A: Yes. Equitrans and National Fuel also face less supply risk than GTN. Both companies transport Gulf Coast gas supplies via interconnections with other pipelines. As discussed above, the outlook for Gulf Coast production is more favorable than the outlook for Canadian imports. Moreover, Equitrans and National Fuel will also benefit from the construction of LNG import terminals in the Gulf Coast area. Equitrans transports Gulf Coast gas supplies that it receives through interconnections with Texas Eastern, Tennessee, Columbia, and Dominion. Equitrans also transports substantial volumes of Appalachian-produced gas.[26] National Fuel transports Gulf Coast gas supplies through interconnects it has with Texas Eastern, Tennessee, Columbia, Dominion, and Transco. National Fuel also transports Appalachian production and WCSB gas supplies delivered via TransCanada's Mainline (at Niagara).

Furthermore, National Fuel's supply risk is mitigated significantly by virtue of its proximity to the Dawn Hub, which allows National Fuel to access diverse and liquid gas supplies.[27] In recent years, the Dawn Hub has become a significant and highly liquid market center because of the large storage capacity at Dawn and because of Dawn's centralized location in Ontario, which allows it to access WCSB, Gulf Coast, and Mid-Continent supplies.[28] Specifically, there is 240 Bcf of storage capacity located at the

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[26] Appalachian-produced gas delivered directly to Equitrans accounts for roughly 26% of the gas transported by Equitrans. The remainder of Equitrans' gas supplies are received from interconnects with Texas Eastern (41%), Tennessee Gas Pipeline (16%), Columbia Gas (7%), Dominion (7%) and National Fuel (3%). *See* Testimony of Andrew Murphy in Docket No. RP04-203 (March 1, 2004), Exhibit ELP-7, Schedule 2.

[27] Like National Fuel, Tennessee Gas Pipeline also benefits from its ability to access diverse and liquid gas supplies at Dawn. In addition, Tennessee also transports (1) WCSB supplies via an interconnection with TransCanada at Niagara, (2) Eastern-Canadian (Nova Scotia) gas supplies via an interconnection with Maritimes & Northeast Pipeline at Dracut, Massachusetts, (3) Appalachian-produced gas, and (4) Gulf Coast gas supplies, as described above.

[28] A 2004 Staff Report by FERC's Office of Market Oversight and Investigations recognized the supply diversity that is achieved at Dawn: "The Dawn Hub is an increasingly important link that integrates gas produced from multiple basins for delivery to customers in the Midwest and Northeast . . . Dawn has many of the attributes that

Dawn Hub, owned by Union (145 Bcf) and Enbridge (95 Bcf).[29] The Dawn Hub accesses WCSB gas supplies via the Alliance and Vector Pipelines and via the TransCanada Mainline and Great Lakes Gas Transmission systems. The Dawn Hub also accesses Gulf Coast and Anadarko/Mid-Continent supplies via the Panhandle Eastern and ANR pipelines.[30]

In addition to its access to the Dawn Hub, National Fuel also has access to (and is the administrator of) the Ellisburg-Leidy Hub. The Ellisburg-Leidy Hub is one of three market centers in the Northeast United States, with access to 33 storage fields with an estimated working gas capacity of 104 Bcf.[31]

Q: What are your conclusions regarding the supply risks facing GTN relative to the supply risks of the proxy group?

A: GTN faces well above-average risks due to it reliance on the WCSB as its primary source of supplies. Many forecasters believe that production in the WCSB has plateaued and will decline in the coming years. Moreover, increasing demand for gas in Canada will also make less gas available for import into U.S. markets. Other pipelines in the proxy group have lower supply risks due to more favorable supply outlooks for the production areas they access, their ability to access emerging LNG supplies, or greater supply diversity.

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customers seek as they structure gas transactions at the Chicago Hub: access to diverse sources of gas production; interconnection to multiple pipelines; proximity to market area storage; choice of seasonal and daily park and loan storage services; liquid trade markets and transparent pricing; and opportunities to reduce long-haul pipeline capacity ownership by purchasing gas at downstream liquid hubs." 2004 State of the Markets Report, p. 161.

29 *See* "What Makes Union Gas' Dawn Hub Market The Busiest On The Continent?," Power & Gas Marketing, November/December 2001.

30 *Id*.

31 *See*, for example, "Natural Gas Market Centers and Hubs: A 2003 Update," Energy Information Administration, October 2003, p. 7-8.

IV. MARKET RISK

Q: What is GTN's primary market?

A: GTN's primary market is California. While GTN also provides transportation to markets in Washington and Oregon, roughly 73% of volumes that are transported on GTN flow to California.[32] In 2004 GTN transported a total of 1.6 Bcf/d to California, of which 1.2 Bcf/d was transported to Northern California and the remaining 0.4 Bcf/d was transported to Southern California.[33]

Q: What are the characteristics of GTN's primary market?

A: California relies on out-of-state imports for roughly 85% of its gas requirements (with only 15% being provided by in-state production). These supplies are imported over 5 pipelines that access 4 supply basins. Specifically, southwest U.S. supplies from the San Juan and Permian basins are transported over the EPNG and Transwestern pipelines. San Juan Basin supplies are also transported over the Southern Trails pipeline. Rocky Mountain supplies are transported over the Kern River pipeline, and WCSB supplies are transported on GTN. Figure 3 shows the sources for the gas supplies delivered to California in 2004.

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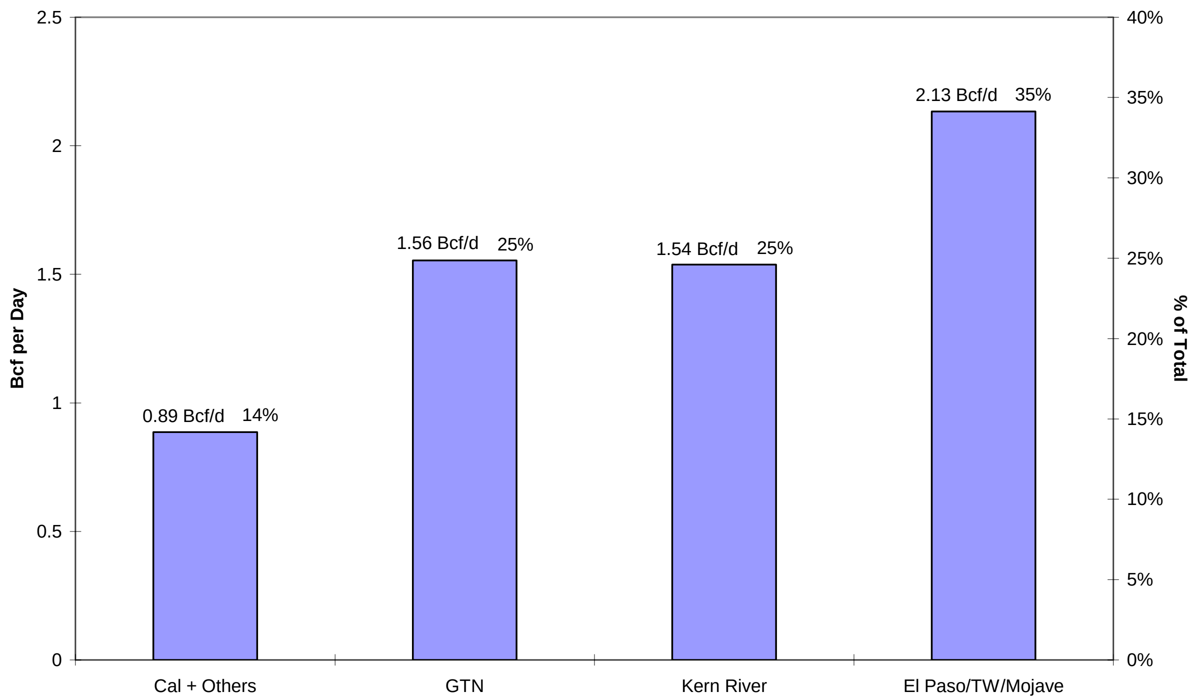
[32] Prepared Direct Testimony of GTN Witness Leslie Ferron-Jones, Exhibit No. GTN-26 at p. 6.
[33] California Gas Report, 2005 Supplement, p. 8.

Figure 3

Sources of California Gas Supplies in 2004



Source: California Gas Report 2005 Supplement.

Q: What recent changes have taken place in the California gas market?

A: In the 2001-2003 period there were several pipeline expansions that significantly increased the amount of transportation capacity to California. Kern River expanded its capacity to California by 135,000 Dth/d in July 2001, by an additional 10,500 Dth/d in May 2002, and by an additional 900,000 Dth/d in May 2003. Southern Trails pipeline converted a crude oil pipeline to natural gas that provided an incremental 80,000 Dth/d from the San Juan Basin to the California border starting in June 2002. Transwestern expanded its capacity to the California border by 150,000 Dth/d during 2002. GTN expanded capacity by 210,000 Dth/d from Kingsgate to Malin in 2002.

In addition to these pipeline expansions to California, there were expansions of the intra-state pipeline system that created additional receipt point capacity (thus allowing more gas to flow into the state). For example, SoCalGas expanded its backbone system by 375 MMcf/d in 2002, with expansions at North Needles (50 MMcf/d), Wheeler Ridge (85 MMcf/d), Kramer Junction (200 MMcf/d), and on Line 85 (40 MMcf/d). Likewise, PG&E's California Gas Transmission expanded the capacity of its Redwood path (which receives gas from GTN at Malin) by 180 MMcf/d in 2002.[34]

More recently, El Paso Natural Gas received FERC approval in June 2005 to acquire 88 miles of a crude oil pipeline from Ehrenberg, Arizona, to Cadiz, California, and convert it to natural gas service. The pipeline, known as Line 1903, was placed into service in December 2005. In conjunction with capacity on Mojave Pipeline, Line 1903 allows El Paso to deliver gas from its North system to its South system at Ehrenberg. At Ehrenberg, gas can be delivered into the SoCalGas system, the North Baja Pipeline, or eastward into El Paso's South system. As discussed below, Line 1903 may eventually allow LNG supplies from Baja California, Mexico, to flow into Northern California.[35]

Q: How have these changes affected GTN's business risk?

A: While some of the changes are beneficial to GTN (*e.g.*, increased access to the SoCalGas system resulting from the Wheeler Ridge expansion), other changes have clearly increased GTN's business risk. In particular, the increased amount of interstate pipeline

[34] PG&E California Gas Transmission press release dated August 28, 2002.

[35] In addition to the pipeline expansions described, there have also been expansions of gas storage capacity in California. For example, Wild Goose Storage expanded its underground storage facility in northern California in 2004. The expansion increased Wild Goose's storage capacity from 14 Bcf to 24 Bcf. In addition, the expansion increased the facility's injection rate from 80 MMcf/d to 450 MMcf/d, and its withdrawal rate from 200 MMcf/d to 480 MMcf/d.

capacity to the California border has significantly devalued pipeline capacity on all pipelines serving the state, including GTN. As discussed by GTN Witness Ferron-Jones, there is currently a significant amount of excess pipeline capacity to California, over 2 Bcf/d in the recent past.[36] GTN Witness Ferron-Jones also discusses how GTN has had difficulty selling its unsubscribed capacity at discounted prices in this environment. This unsubscribed capacity has become available as GTN shippers have decided not to renew expiring firm contracts. GTN currently has approximately 300,000 Dth/d of long-term firm capacity from Kingsgate to Malin that is unsubscribed on a long-term basis. This number is projected to grow to approximately 400,000 Dth/d by December 31, 2006.

Q: What other changes are contributing to increased business risk for GTN?

A: First, GTN's role in serving California has changed in recent years. While GTN historically operated as a baseload pipeline at very high load factors, its load factor has decreased in recent years as additional capacity has been built to California and relative prices in producing basins have changed. Second, GTN is facing additional contract expirations for capacity to its California destination market that increases its business risk significantly, especially in light of the current excess capacity situation into California and GTN's difficulty in selling its unsubscribed capacity at discounted prices. Third, a new LNG import terminal currently under construction in Baja California, Mexico will result in a new source of supplies to the California market as early as 2008, which also increases GTN's business risk.

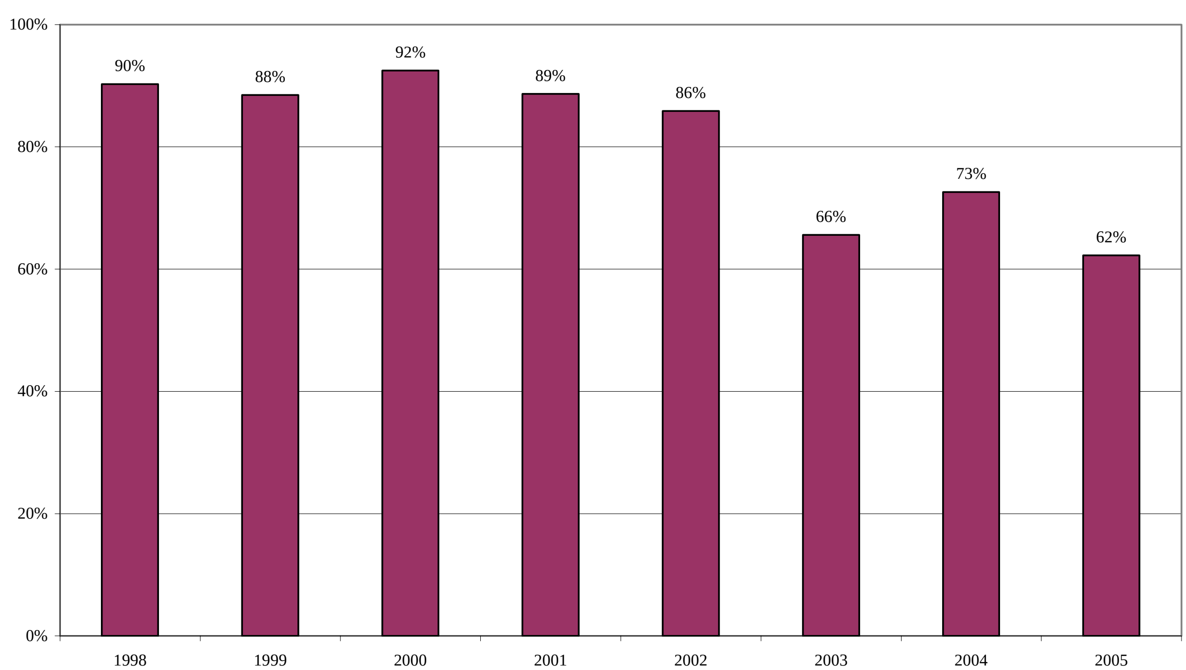
Q: How have load factors on GTN changed in recent years?

[36] Prepared Direct Testimony of Leslie Ferron-Jones, p. 11 (Exhibit No. GTN-26).

A: As shown in Figure 4, load factors on GTN frequently were near 90% historically, but have fallen from those levels in recent years, reaching a low of 62% in 2005. Contributing to these declining load factors have been the increase in pipeline capacity to the California border and changes in the relative prices for gas produced in the WCSB and gas produced in the San Juan Basin. As shown in Figure 5, the price differential between San Juan Basin and WCSB gas supplies has declined over time. Prior to 2001, San Juan Basin supplies were almost always priced higher than WCSB supplies. Since 2001, WCSB prices have frequently exceeded San Juan Basin prices, thereby allowing San Juan Basin supplies to more effectively compete in northern California markets (and making WCSB supplies transported via GTN less competitive).

Figure 4

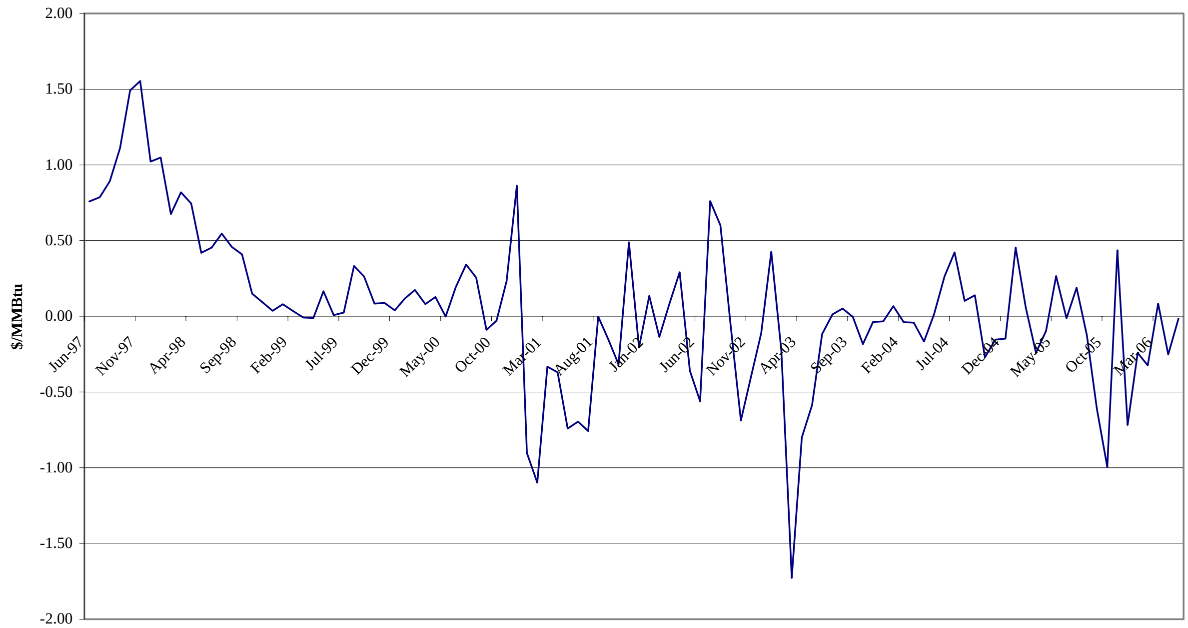
Load Factors on GTN
(at Malin)



Sources: Data provided by GTN.

Figure 5

Bidweek Price Differential between San Juan Basin and AECO



Note: Bidweek price differential is calculated as the San Juan Basin price minus the AECO price.

Source: Gas Daily.

Q: How much capacity is expiring on GTN in the next several years?

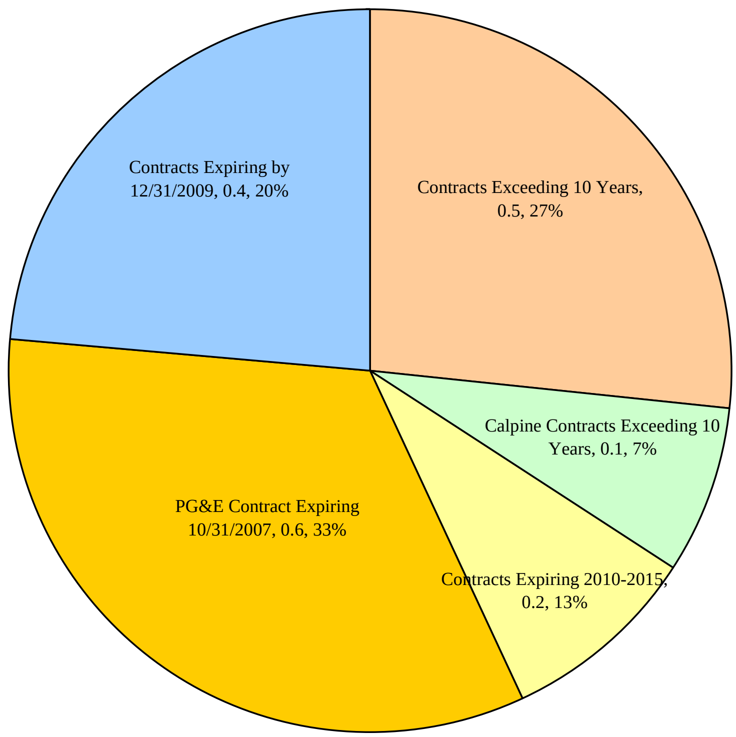
A: As shown in Figure 6, GTN is facing the expiration of a significant amount of its long-haul firm transportation contracts to California (from Kingsgate to Malin) in the next few years. Specifically, nearly 1,000,000 Dth/d of long-haul capacity will expire in the next 3.5 years.[37] Of particular significance is the expiration of GTN's contract with PG&E. PG&E is the single largest holder of pipeline capacity on GTN, holding a total of 610,000 Dth/d from Kingsgate to Malin (over 25% of GTN's capacity to Malin). PG&E held this capacity under a long-term contract that was effective in 1993. It expired in October

[37] GTN also faces the expiration of short-haul contracts in the next 3.5 years. Roughly 150,000 Dth/d of Kingsgate to Stanfield capacity and 100,000 Dth/d of Stanfield to Malin capacity is set to expire by December 31, 2009.

2005, but PG&E has elected to exercise the evergreen provisions of its contract to extend the contract on a year-to-year basis (it is currently set to expire on October 31, 2007).

Figure 6

GTN's Contracted Firm Capacity (Kingsgate to Malin, 1.8 Million Dth/d)



Source: GTN Index of Customers, 2nd Quarter 2006.

Q: Does PG&E have competitive alternatives to GTN for its gas supply?

A: Yes. PG&E's competitive alternatives to GTN include gas supplies from the U.S. Southwest (transported via Transwestern or EPNG) and gas supplies from the Rocky Mountains (transported via Kern River). LNG supplies will also become an alternative for PG&E in the coming years. PG&E described how it viewed LNG as a potential substitute for interstate pipeline capacity in comments it submitted (in February 2004) in a CPUC rulemaking:

> By the end of 2007, all of PG&E's core interstate and Canadian pipeline capacity contracts will expire or convert to year-to-year

> terms under the evergreen provisions. The expiration of these contracts presents PG&E with a significant opportunity to review its current portfolio of capacity holdings, as well as negotiate for any additional capacity that may be necessary to provide the needed level of reliability and price protection for PG&E's core customers. Depending on the location of potential LNG facilities, LNG may also be considered as a potential substitute for storage, interstate pipeline capacity or basin supplies.[38]

Q: Does PG&E currently hold firm capacity on pipelines other than GTN?

A: Yes. PG&E also holds transportation capacity on Transwestern pipeline (150,000 Dth/d) and on EPNG (200,000 Dth/d), and PG&E has requested CPUC approval for additional winter-only transportation capacity on EPNG and Kern River.[39] In April 2006, PG&E requested CPUC approval for a new transportation contract with Transwestern that would replace its existing contract which expires in March 2007. The new contract has the same capacity as the existing contract (150,000 Dth/d), a discounted reservation rate ($0.30/Dth versus $0.40/Dth under the existing contract), and an expiration date of March 2010. In its request to the CPUC, PG&E noted that a benefit of the new contract was:

> Continued access to the currently lower-cost supplies from the San Juan Basin. San Juan Basin supplies are expected to be competitively-priced through the term of the new [transportation contract].[40]

Likewise, in 2005 PG&E renegotiated its EPNG capacity at a discount to maximum tariff rates. Specifically, PG&E signed three new capacity contracts from the San Juan Basin to the California border with staggered expiration dates. The three

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[38] Phase I Proposals and Data Response of Respondent Pacific Gas & Electric Company in R.04-01-025, February 24, 2004, p. 9 (included as Exhibit No. GTN-44).

[39] *See* PG&E Advice Letter 2737-G, filed with the CPUC on June 16, 2006 (included as Exhibit No. GTN-45). PG&E proposes purchasing 50,000 Dth/d of EPNG capacity at a reservation rate of $0.12/Dth and 29,200 Dth/d of Kern River capacity at a reservation rate of roughly $0.40/Dth. The effective dates of both of the proposed capacity purchases would be from December 1, 2006 to February 28, 2007.

[40] *See* PG&E Advice Letter 2719-G, filed with the CPUC on April 5, 2006 (included as Exhibit No. GTN-46). PG&E's request also noted that "Supplies from the San Juan Basin have been, and are expected to continue to be consistently competitive with gas supplies from the Western Canadian Sedimentary Basin and the U.S. Rocky Mountain producing region."

capacity contracts are for 25,000 Dth/d (expiring 2007), 90,000 Dth/d (expiring 2008), and 85,000 Dth/d (expiring 2010). During PG&E's recent negotiations, PG&E explained in a letter to EPNG how it had numerous alternatives to El Paso capacity and that a discount to El Paso's maximum tariff rate was justified in light of market circumstances:

> In evaluating whether to renew PG&E's Contract 9Q7P firm transportation service arrangement with El Paso, PG&E evaluated historical and forward market indicators, as well as several competitive alternatives that were available to us at the time we started negotiating this new arrangement. As the data below indicate, recent San Juan to PG&E Topock historical price differentials have trended, with few exceptions, below El Paso's maximum California tariff rate, indicative of the lower value established by the market for such capacity.
>
> Perhaps even more significantly, forward monthly price quotations available to PG&E during the negotiation period were significantly below San Juan commodity prices plus El Paso's maximum rate to the Southern California border. Furthermore, Topock commodity gas transactions typically trade at discounts to the Southern California border, indicating that the market value of El Paso's northern pipeline system from San Juan to Topock is less than the market value of El Paso capacity to Southern California. Because of the numerous alternatives available for serving the PG&E service area, including the proposed development of LNG terminals on the West Coast as early as 2008, PG&E expects that the forward spreads for Topock will continue to trade below El Paso's maximum tariff rate for longer than the term of the proposed agreements.[41]

Q: In the letter you just cited, PG&E referred to the proposed development of LNG terminals on the West Coast as early as 2008. What LNG terminals are being proposed on the West Coast?

A: Several are proposed, but only one is in an advanced stage with construction underway.[42] Specifically, Sempra Energy has begun construction on the Energia Costa Azul LNG import terminal in Baja California, Mexico. The facility is expected to come on line in

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[41] *See* letter from Trista Berkovitz to Sean Kolassa dated April 13, 2005, included as Exhibit No. GTN-47.

[42] Aside from Sempra's Energia Costa Azul project, other LNG projects proposed to serve southern California include Woodside's Oceanway project, BHP Billiton's Cabrillo Port terminal, and Sound Energy Solutions' Long Beach project.

early 2008 with an initial capacity of 1.0 Bcf/d. In addition, the facility could be expanded to provide up to 2.5 Bcf/d of capacity, and Sempra recently announced an open season for the incremental 1.5 Bcf/d of expansion capacity.[43]

With respect to the initial 1.0 Bcf/d of terminal capacity, Sempra envisions 0.5 Bcf/d of LNG supplies being used to meet Mexican demand, and the remaining 0.5 Bcf/d being available to California and Southwestern gas markets. In fact, Sempra recently entered into a settlement agreement that contains a provision requiring Sempra to sell to SDG&E and SoCalGas "all regasified LNG from Energia Costa Azul up to 500 MMcf/d" not sold to CFE or other Mexican entities.[44]

Q: Is the State of California encouraging the development of LNG terminals on the West Coast?

A: Yes. The California Energy Commission's ("CEC's") 2003 Integrated Energy Policy Report ("2003 IEPR") recommended that California actively encourage infrastructure enhancements such as additional pipeline capacity, incentives for increased use of in-state storage, and access to LNG supplies.[45] In fact, the CEC specifically recommended that California encourage the construction of LNG facilities and infrastructure and coordinate permitting to facilitate the development of these facilities on the West Coast.[46]

In 2004, the CPUC established a rulemaking proceeding to establish policies and rules to ensure reliable long-term supplies of natural gas to California. The CPUC was concerned that, absent CPUC action, there may not be sufficient gas supplies and/or

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[43] *See* Sempra Energy press release dated March 13, 2006.

[44] *See* Attachment B of January 4, 2006 Settlement Agreement Between the Sempra Parties and the Settling Claimants in Natural Gas Antitrust Cases I, II, III, IV before the Superior Court of the State of California, County of San Diego, J.C.C.P. Nos. 4221, *et al*.

[45] 2003 Integrated Energy Policy Report, California Energy Commission, p. vi.

[46] *Id*., p. viii.

infrastructure in the long term to meet California gas requirements.[47] In establishing the rulemaking, the CPUC pointed to the CEC's 2003 IEPR recommendations, including promoting infrastructure enhancements such as access to LNG facilities on the West Coast. The CPUC also found that it needed to make certain decisions in 2004 so that "access to imported natural gas supplies (*e.g.*, from LNG facilities) will be available to meet the new challenges we face."[48] Another factor the CPUC pointed to in explaining the need for its rulemaking was the forecasted declines in Canadian imports.[49]

The CPUC rulemaking required that each California gas utility (PG&E, SDG&E and SoCalGas) submit a proposal concerning guidelines for how natural gas supplies from LNG facilities can access their intrastate pipelines and distribution facilities to the extent LNG terminals are constructed on the West Coast.[50] The CPUC specifically asked SoCalGas/SDG&E to address several issues regarding how LNG would access its system through Otay Mesa.[51]

Q: What risks are there to GTN from the CPUC's encouragement of LNG supply alternatives and specifically from Sempra's Energia Costa Azul LNG terminal?

A: The Energia Costa Azul LNG terminal increases GTN's business risk by introducing a new source of supply into the southern California market that GTN has historically served. Specifically, these LNG supplies will be transported to southern California through interconnects with the SoCalGas/SDG&E system at Otay Mesa, California, and at Ehrenberg, Arizona. The CPUC approved Otay Mesa as a receipt point in a September

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[47] Order Instituting Rulemaking to Establish Policies and Rules to Ensure Reliable, Long-Term Supplies of Natural Gas to California, R. 04-01-025, 1/27/2004, p. 2.
[48] *Id.*, pp. 2-3.
[49] *Id.*, pp. 7-8.
[50] *Id.*, p. 13.
[51] *Id.*, p. 14.

2004 decision in its rulemaking proceeding.[52] Otay Mesa is the interconnection between the TGN pipeline in Mexico and the SoCalGas/SDG&E gas transmission system at the U.S.-Mexico border. When the Energia Costa Azul LNG terminal becomes operational in 2008, LNG supplies will be available to California at Otay Mesa via the TGN pipeline and at Ehrenberg via the BajaNorte and North Baja pipeline systems.[53]

Q: Does Sempra's Energia Costa Azul LNG terminal increase business risk in GTN's northern California market?

A: Yes. The terminal potentially impacts GTN's northern California market either directly (in the event LNG supplies from the new terminal are transported into northern California) or indirectly (by potentially displacing gas supplies from the San Juan basin which would then be available for delivery to Northern California). PG&E has acknowledged these potential impacts in comments it made in the CPUC's rulemaking proceeding:

> LNG holds the promise of an additional supply source which will moderate prices as well as create additional opportunities to enhance diversity of supply. PG&E's core customers are likely to benefit from the arrival of LNG either through contracting directly for supplies or indirectly from the freeing-up of traditionally-sourced supplies that are displaced by LNG in other downstream markets.[54]

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[52] CPUC D. 04-09-022 (September 2, 2004).

[53] The North Baja and BajaNorte pipelines currently flow gas in a north to south direction (from the southwest U.S. to Mexico), as does the TGN pipeline. However, when Energia Costa Azul begins importing LNG in 2008, gas flow will be reversed to flow from south to north on the TGN pipeline and on the BajaNorte and North Baja pipelines. North Baja pipeline recently filed an application with the FERC (Docket No. CP06-61) to modify its existing Ehrenberg Compressor Station and Ogilby Meter Station to allow for gas flow in the opposite direction (south to north) from the existing configuration.

[54] Phase 1 Proposals and Data Response of Respondent Pacific Gas & Electric in R. 04-01-025, February 24, 2004, pp. 13-14 (Exhibit No. GTN-44). In its proposals, PG&E explained:

> PG&E supports the development of LNG facilities on the west coast. A new alternative supply source is likely to provide substantial gas commodity cost benefits to consumers in the PG&E service territory in much the same way as PG&E's expansion of the gas transmission Line 400/401 system from Canada benefits California consumers. Significant alternative gas supply sources help

Q: How could PG&E directly access LNG supplies in Baja California?

A: In its rulemaking comments, PG&E explained to the CPUC that it could access LNG supplies from LNG facilities proposed in southern California and Mexico in three ways. First, it could build an interconnection between its Line 300 and El Paso's Line 1903, and access LNG supplies from North Baja at Ehrenberg. Second, it could access Baja Mexico LNG supplies through a new pipeline along the Colorado River between Ehrenberg and Topock. Third, it could access these supplies if SoCalGas allowed nominations from a Los Angeles Citygate delivery point to an off-system connection with PG&E.[55] More recently, PG&E explained to the FERC that it foresees an interconnection between its Line 300 and El Paso's Line 1903:

> PG&E envisions that customers in PG&E's service area in central and northern California will be able to access LNG supplies that arrive via the [North Baja Pipeline] at the Ehrenberg trading point, by means of an interconnection between El Paso's Line 1903 and PG&E's Line 300. PG&E believes that this will increase the supply of natural gas flowing into California, to the benefit of all gas customers. PG&E recommends that the Commission approve [North Baja Pipeline's] application as a means of fortifying the gas

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> reduce price volatility by increasing available supplies and providing greater gas-on-gas competition.
>
> PG&E has two primary interests in the development of LNG facilities. The availability of a LNG regasification facility on the west coast will benefit PG&E's customers by providing an additional supply source and gas-on-gas competition. PG&E also has a role in the transportation of LNG supplies and the management of gas quality issues associated with LNG. Thus, PG&E's comments herein with respect to LNG are from the perspectives of a buyer, and a transporter and distributor of gas.

[55] *Id*., p. 20. In its rulemaking decision (D. 04-09-022), the CPUC recognized that PG&E could access LNG supplies if SoCalGas allowed nominations from a Los Angeles Citygate point to an off-system connection with PG&E and ordered SoCalGas/SDG&E to include a proposal for firm off-system deliveries into PG&E's service territory in its (then) upcoming application to establish an integrated transmission system and firm access rights. In its May 5, 2006, application to the CPUC, SoCalGas included a proposal for firm off-system deliveries into PG&E's system. *See* Testimony of Richard M. Morrow, Rodger R. Schwecke, and Stephen A. Watson dated May 5, 2006 in A. 04-12-004.

infrastructure in California and encouraging the development of LNG.[56]

Q: Is GTN exposed to increased business risk even in the absence of a direct interconnection between PG&E's gas transmission system and Line 1903?

A: Yes. As PG&E described, northern California customers may benefit if traditional supplies are displaced by LNG supplies. One possible scenario is that San Juan Basin supplies delivered to southern California could be displaced by new LNG supplies and be available for delivery to northern California, potentially displacing Canadian supplies delivered via GTN. Significantly, San Juan Basin supplies do compete for the northern California market, and have become more competitive in recent years, as I discussed above.

Q: Are there other possibilities for LNG supplies accessing Northern California?

A: Yes, although it is speculative at this point, PG&E may be able to access supplies from LNG import facilities that could be constructed in Oregon. In fact, PG&E, Williams' Northwest Pipeline, and Fort Chicago Energy Partners recently announced the development of the Pacific Connector Gas Pipeline, a new pipeline that would deliver LNG supplies from a proposed LNG import terminal in Coos Bay, Oregon, to West Coast markets, including California.[57] Specifically, the Pacific Connector would link the proposed Jordan Cove LNG terminal to Williams' Northwest Pipeline system near Roseburg, Oregon, and the Tuscarora and PG&E gas transmission systems near Malin, Oregon. The Pacific Connector is proposed as a 1.0 Bcf/d pipeline. Were it to be built, it

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[56] *See* March 13, 2006 intervention of PG&E in Docket No. CP06-61, p. 4. In its November 2004 intervention in the FERC certificate proceeding for EPNG's Line 1903 (Docket No. CP05-2), PG&E requested that the Commission condition its certificate authorization for Line 1903 on EPNG's construction of interconnection facilities with PG&E's gas system within California. PG&E's request was denied by the Commission in its Order dated June 16, 2005.

[57] Williams press release dated February 8, 2006.

would allow PG&E to access LNG supplies from the Jordan Cove terminal and substantially bypass GTN (GTN's capacity into California is roughly 2.1 Bcf/d).

Q: Are there any other factors that you believe are relevant to understanding the risk to GTN of the entry of LNG into California?

A: Yes. Decisions by the CPUC regarding the ratemaking treatment of potential expansions of the PG&E and SoCalGas intrastate pipeline systems could affect how much LNG is ultimately made available in California, which in turn could impact the demand for GTN capacity. Specifically, the CPUC may have to decide whether to price expansions on an incremental basis (paid for solely by the new shippers accessing the intrastate system, namely the LNG developers) or on a rolled-in basis (paid for by new and existing shippers, including core ratepayers). In the CPUC's rulemaking proceeding, both PG&E and SoCalGas proposed rolled-in rate treatment for expansions of their system that increased access to new sources of supply. For example, SoCalGas proposed a rule that rolled-in rate treatment apply to all projects that cost less than $100,000 per MMcf/d (with a maximum cost for all projects of $200 million).[58] Likewise, PG&E proposed that the costs of transmission capacity investments be shared proportionally with all customers.[59] To date, the CPUC has indicated a presumption that LNG suppliers will pay for actual system infrastructure costs associated with their projects, but that it will

58 Proposals of San Diego Gas & Electric and Southern California Gas Company in R.04-01-025, dated February 24, 2004, pp. 70, 78.

59 Prepared Testimony of Shaun E. Halverson in R. 04-01-025 (June 14, 2005), p. 2-4. Ms. Halverson stated, "This ratemaking principle is also important from a forward-looking perspective, as California looks towards new liquefied natural gas (LNG) supply sources to ensure adequate and reliable long-term natural gas supplies. If PG&E were to expand its Baja Path (Line 300) transmission system to access an LNG supply source from the South, for example, such an expansion would benefit all of PG&E's customers with new and potentially lower-cost gas supplies and increased gas-on-gas competition. For PG&E's backbone system to accommodate future LNG supplies and to facilitate increased gas-on-gas competition, it is essential that the costs of capacity expansions to access future gas supplies be allocated proportionally to all customers who will benefit from the supply access."

evaluate requests for rolled-in rate treatment on a case-by-case basis.[60] Were the CPUC to allow rolled-in rate treatment for intrastate expansions designed to increase access to LNG supplies, such a decision would increase GTN's business risk.

Q: What is your assessment of the market risks faced by GTN?

A: GTN faces market risks that are above average given the number of supply basins and interstate pipelines that serve California demand. These risks are exacerbated by excess pipeline capacity to California, recent contract expirations that have resulted in unsubscribed capacity (which GTN has had difficulty re-selling), additional contract expirations GTN faces in the next few years, the short-term contractual position GTN has with respect to PG&E, and the pending entry of LNG supplies on the U.S. West Coast, all of which create a unique situation for GTN relative to other proxy group pipelines.

Q: Which pipelines in the proxy group do you believe face lower market risks than GTN?

A: I believe several pipelines in the proxy group face lower market risks than GTN, including Northwest, Questar, Southern Natural, National Fuel and Transco. As I will discuss, some of these pipelines face limited competition in the markets they serve, and therefore, are demonstrably less risky than GTN. Other pipelines are closely integrated with affiliated LDCs, which significantly reduces their market risk. Finally, some of the pipelines operate in markets that are relatively capacity constrained, which makes them less risky than GTN whose capacity has been devalued due to excess capacity to California.

Q: Why does Northwest have lower market risk than GTN?

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60 CPUC Decision 04-09-022 (September 2, 2004), p. 68.

A: Northwest has a very strong market position in its Pacific Northwest markets. While it does face some competition from GTN in some parts of eastern Washington and Oregon, it is the only interstate pipeline serving Seattle, Tacoma, Portland and Salem. Thus, unlike GTN, Northwest faces little competition in its primary market area. Northwest itself has recognized its relatively strong market position in its 2005 10-K filing with the Securities and Exchange Commission:

> No other interstate natural gas pipeline company presently provides significant service to our primary gas consumer market area. However, competition with other interstate carriers exists for expansion markets.[61]

Q: Why does Questar have lower market risk than GTN?

A: Questar has a very strong market position in Utah, Wyoming and Colorado. Its transportation system provides market access for growing Rocky Mountain gas supplies. Specifically, Questar provides transportation from the Overthrust, Green River, Skull Creek, Sand Wash, Uintah, Piceance, and Ferron basins, as well as other basins in the Rocky Mountain area. Its primary market area is the Wasatch Front area of Utah (which includes Salt Lake City). Questar faces some competition in Utah (from Kern River pipeline), but has been able to expand its system significantly in recent years to provide growing Rocky Mountain supplies to growing markets in Utah. For example, in 2001, Questar expanded its southern system by 272,000 Dth/d, which was supported by seven contracts that allowed shippers to deliver gas from Price, Utah westward to the Wasatch Front and to an interconnection with the Kern River pipeline (also in Utah).[62] In 2005,

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[61] Northwest Pipeline 10-K dated December 31, 2005.

[62] 95 FERC ¶ 61,404 (Docket No. CP00-68, June 14, 2001). In its preliminary determination approving the expansion (December 14, 2000), the FERC found:

Questar again expanded its system by 102,000 Dth/d from various receipt points on its system to the Kern River system.[63]

Questar's service to its affiliated LDC, Questar Gas, significantly reduces its market risk.[64] Questar Gas is the largest shipper on Questar, holding roughly 900,000 Dth/d on a year round basis, of which roughly 800,000 Dth/d is under contract until 2017.[65] Questar Gas also holds an additional 50,000 Dth/d of winter-only capacity on Questar.[66]

In addition to its service to Questar Gas, Questar also provides transportation services to non-affiliated entities that transport gas to other pipelines. For example,

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> … there will be no adverse impact on TransColorado or other existing pipelines and their customers from Questar's proposed project. TransColorado is not a competing pipeline in this proceeding. Questar's proposal does not rely on volumes presently being shipped on TransColorado. Thus, TransColorado is not subject to loss of existing load. Further, TransColorado is not a competing pipeline since it does not appear from the record that TransColorado could provide the same services that Questar proposes to provide. Nor does any other pipeline exist that would compete with Questar's proposed service.
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> ****
>
> Nor is there any record evidence that Questar's proposal will result in load loss on any other pipeline systems, including TransColorado and Kern River. No evidence suggests that the identified expansion shippers (i.e., Questar Gas, Texaco, and CIG Resources) are relinquishing existing firm service and capacity on other systems in favor of service and capacity on Questar's proposed project. This project is essentially a supply project in that it is designed to make available new competitive gas supplies from the Price, Utah area and those connected to CIG; it does not propose to serve specific consuming markets apart from the Wasatch Front which is currently served by Questar Gas. As a result, Questar's proposed project may benefit existing shippers on Kern River by enabling them, via Questar's proposed interconnect, to access to additional supplies which may create price competition and more options in the event current supplies are interrupted. We conclude that no other pipeline or its existing customers will be adversely impacted by Questar's proposed project. (footnotes omitted)

[63] 110 ¶ FERC 61,035 (Docket No. CP05-5, January 21, 2005).

[64] Questar Gas is the LDC that serves Utah, including Salt Lake City and Provo.

[65] Questar Gas also holds 53,000 Dth/d on Kern River through a contract that expires in 2018. It uses this 53,000 Dth/d in the November-March period, and assigns 50,000 Dth/d to Nevada Power during the April-October period.

[66] Questar Corporation's 10-K dated December 31, 2005 reports that the 951,000 Dth/d of capacity held by Questar Gas represents 50% of Questar's reserved capacity (during the three coldest months of the year). Questar's 10-K also reports that Questar Pipeline's transportation system is nearly fully subscribed.

roughly 21% of the capacity on Questar is contracted by entities that transport gas to the Kern River pipeline. Another 10% is contracted by PacifiCorp for service to a new electric generation plant in Utah that went into service in 2005.

Q: Why does Southern Natural have lower market risk than GTN?

A: Southern Natural faces competition in its Alabama, Georgia, and South Carolina markets from one primary competitor, Transco. However, the competition from Transco appears to be quite limited, as two of the largest shippers on Southern Natural have explained. For example, Atlanta Gas Light recently explained how it will continue to rely on its interstate transportation contracts with Southern Natural Gas for the next 20 years:

> The large majority of [Southern Natural's] capacity will be needed today and 20 years from now. The Ex-Atlanta SNG, Rome, Augusta, Macon, Savannah, Brunswick, and South Georgia Pools (seven of [Atlanta Gas Light's] nine pool groups) are solely supplied by [Southern Natural]. Currently, there is no pipeline competition to serve these areas. It would be difficult for a new green-field pipeline to expand from the pipeline corridor east into [Atlanta Gas Light's] service territory with economical rates. The Atlanta Pool does have pipeline competition from Transco, and to a lesser degree East Tennessee Natural Gas Company.[67]

Similarly, Alabama Gas Company has also recently explained its dependence on Southern Natural's capacity, which is closely integrated with Alabama Gas Company's distribution system:

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[67] Pre-Filed Testimony of Steve Moore and Ernie Brake before the Georgia Public Service Commission, Docket Nos. 8516-U and 18437-U, July 1, 2004, p. 20. Their testimony also explained how Atlanta Gas Light assessed the market for transportation alternatives: "AGLC hosted meetings with [Southern Natural], Transco, and East Tennessee. These pipelines are directly connected to AGLC's distribution system and could potentially serve incremental demand in the Atlanta Pool Group. However, these pipelines are fully subscribed for traditional long haul transportation capacity. The construction of new green-field pipelines from other pipeline companies not currently serving AGLC would likely be cost prohibitive, require 15-20 year contract commitments, and take several years to construct." Their testimony continued, " . . . based on the information currently available, the Southeast capacity market and associated pipeline infrastructure is fully subscribed and therefore offers very limited flexibility to make meaningful capacity contract changes."

> Alagasco's service territory is served primarily by one interstate pipeline—Southern Natural Gas Company—and to a lesser extent by Transcontinental Gas Pipe Line Company (Transco), which serves a portion of Alagasco's service territory in the central part of the state. Alagasco's system spans Alabama from the northwestern-most corner of the state to as far south as Choctaw County, and from there as far east as the Georgia state line in Russel County. Although Alagasco has constructed lines to tie together the portions of its distribution system that are near to Southern Natural and Transco, our LDC system is not fully integrated. In fact, Alagasco's service area consists of over 1,000 separate distribution systems constructed around gas delivery points on the Southern Natural pipeline. The only interstate pipeline that ties the entirety of Alagasco's distribution system is Southern Natural.
>
> The Southern Natural and Transco pipelines serve markets well beyond Alabama. Both pipelines flow gas through Alabama into Georgia and South Carolina. Transco gas continues up the East Coast all the way into New York. Of particular importance is the fact these two pipelines provide, in effect, the only source of gas for the rapidly growing markets in the Georgia, the Carolinas, and Southern Virginia. Capacity along this pipeline corridor is utilized at some of the highest load factors of any pipeline system in the country. As a result, discounted firm capacity due to excess capacity is not generally available.[68]

Furthermore, even Southern Natural has described itself (in its 10-K) as the "principal natural gas supplier to the growing southeastern markets of Alabama and Georgia."[69] Southern Natural has placed three expansions into service since 2001, with total capacity of 700 MMcf/d.[70]

Q: Why does National Fuel have lower market risk than GTN?

A: National Fuel faces competition in its service territory from Tennessee Gas Pipeline, Dominion Transmission, and Columbia Gas Transmission, but (like Questar) also

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68 Alabama Gas Corporation's Response to Commission Staff Question 2 in Docket No. U-4708, January 23, 2006.

69 Southern Natural 10-K dated December 31, 2004.

70 *Id.*

provides service to an affiliated LDC, National Fuel Gas Distribution, which significantly reduces its market risk. In fact, National Fuel Gas Distribution has noted the close integration between its system and National Fuel's, commenting that National Fuel "holds" the distribution system together by delivering gas at over 300 points and that National Fuel is, in effect, an extension of the distribution system.[71]

National Fuel Gas Distribution holds 1.1 Bcf/d of firm transportation capacity on National Fuel, which is 50.7% of the total contracted firm transportation capacity on National Fuel.[72] National Fuel reported in its 10-K that it faced contract expirations (that would not be renewed) of 17.2% of its total contracted capacity (5.9% representing affiliate contracts and 11.3% representing unaffiliated contracts) in 2006.[73] However, National Fuel noted that it "has been successful in marketing and obtaining executed contracts for such transportation service previously (at discounted rates when necessary), and expects to continue to do so."[74] National Fuel's view that it expects to be able to sell its capacity suggests it is in a better competitive position than GTN. As discussed by GTN Witness Ferron-Jones, GTN has had difficulty selling capacity that has become

71 Order concerning assignment of capacity dated March 24, 1999, Case 97-G-1380 *et. al.*, at 5.

72 National Fuel Gas Company 10-K dated September 30, 2005. National Fuel Gas Distribution also holds 40.7% of the total firm storage capacity on National Fuel.

73 *Id*. In its 10-K, National Fuel explained how the amount of its capacity that could have expired was higher, (*i.e.*, indicating that most shippers were renewing their capacity): "At the beginning of 2006, 52.9% of Supply Corporation's contracted transportation capacity was committed under affiliate contracts that could have expired or been terminated effective before the end of 2006. Based on contract expirations and termination notices received before the deadline for termination effective within 2006, affiliate contracts representing 5.9% of contracted transportation capacity will actually expire or be terminated effective during 2006. Similarly, 30.7% of contracted transportation capacity was committed under unaffiliated shipper contracts that could have expired or been terminated effective before the end of 2006. Based on contract expirations and termination notices received before the deadline for termination effective within 2006, unaffiliated contracts representing 11.3% of contracted transportation capacity will actually expire or be terminated effective during 2006."

74 *Id*.

available because of contract expirations, even at steeply discounted rates, in light of its market conditions.[75]

Q: Are there other factors that are important to understanding National Fuel's market risk?

A: Yes. It is widely-accepted that gas markets in the U.S. Northeast are relatively capacity constrained relative to other U.S. market areas, including GTN's market area (which is in an excess capacity situation). FERC staff has recognized the tight capacity situation into the U.S Northeast in several recent analyses. For example, in its 2004 State of the Markets Report (published in June 2005), FERC staff noted that the Northeast is vulnerable to natural gas price spikes, especially in the winter when there can be high demand from both residential customers (for space heating) and from electric generators.[76] It also noted more recently in its 2005 Winter Energy Market Assessment that high Northeast prices were expected due to capacity constraints.[77]

National Fuel benefits from the tight market conditions that exist in the U.S Northeast. For example, National Fuel's 68 Bcf of storage capacity is fully subscribed.[78] National Fuel owns and operates 28 natural gas storage fields as well as 4 other storage

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75 Prepared Direct Testimony of GTN Witness Leslie Ferron-Jones, Exhibit No. GTN-26 at pp. 2, 30-31.

76 2004 State of the Markets Report, p. 165. The study further noted that price spikes will continue in the Northeast until additional pipeline and LNG capacity is added, but also described the challenges of developing gas pipeline capacity in the region. *Id*. at p. 172.

77 Winter Energy Market Assessment 2005-2006, Federal Energy Regulatory Commission, October 20, 2005.

78 National Fuel Gas Company 10-K dated September 30, 2005. In its 10-K, National Fuel explained that most of its storage contracts were short-term, but that it expected most contracts to be renewed, "At the beginning of 2006, approximately 86.3% of Supply Corporation's total firm storage capacity (including 44% of Supply's total firm storage capacity contracted for by affiliated shippers) was committed under contracts that could have expired or been terminated before the end of 2006. Based on contract expirations and termination notifications received before the deadline for termination effective within 2006, contracts representing less than 0.5% of Supply Corporation's total firm storage capacity will be terminated during 2006. Supply Corporation has been successful in marketing and obtaining executed contracts for storage service (at discounted rates when necessary) as it becomes available and expects to continue to do so."

fields that it owns and operates jointly with other pipeline companies.[79] National Fuel provides transportation service to and from its natural gas storage facilities for customers in the northeast United States. Moreover, demand for storage is growing. In its 2003 study, the National Petroleum Council found that the New England and Middle Atlantic markets will require an additional 135 Bcf of storage capacity between 2005-2025.[80]

Q: Do the tights markets affect any other pipelines in your proxy group?

A: Yes, Transco is also affected by these market conditions. Transco serves major markets along the eastern seaboard of the United States, including major metropolitan areas in Georgia, North Carolina, Pennsylvania, New Jersey, and New York. Transco does face competition in its markets, including competition from Southern Natural (in Georgia), from Columbia Gas and Texas Eastern (in the mid-Atlantic), and from Texas Eastern and Iroquois Gas Transmission in New York City. Nonetheless, an important distinction between Transco and GTN is that Transco's pipeline terminates in New York City, which is relatively capacity constrained compared to the excess capacity situation in California where GTN terminates.

The tight supply-demand balance in the U.S. Northeast can be seen by looking at the basis differentials between New York City and Henry Hub. These basis differentials have averaged over $1.00/Dth in the 2003-2005 period, well in excess of Transco's maximum tariff rate plus fuel in this period (*See* Figure 7). This is much different than the low basis differentials that exist between Malin and Alberta, Canada, which have

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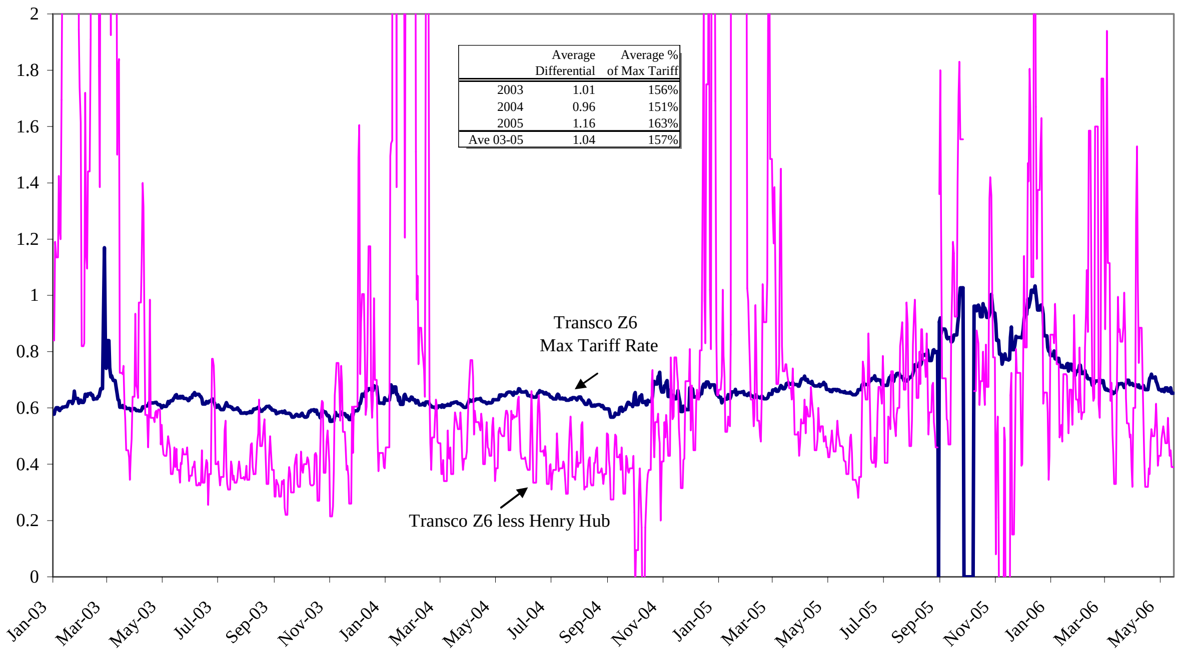
79 *Id.*

80 "Balancing Natural Gas Policy: Fueling the Demands of a Growing Economy," National Petroleum Council, September 2003, Volume IV (Transmission & Distribution Task Group Report), pp. T-8, T-61.

been well below the maximum tariff rate along that corridor. GTN Witness Ferron-Jones describes those low basis differentials in her testimony.[81]

Figure 7

Transco Zone 6 (NY) - Henry Hub Price Differential



Note: Transco Zone 6 Maximum Tariff Rate includes fuel.

Sources: Gas Daily and Transco Tariff.

V. CONTRACT PROFILE

Q: What is the contract expiration profile of pipelines in the proxy group?

A: I show the contract expiration profile of GTN and the proxy group pipelines in Figure 8. As I discussed in Section II, pipelines that are fully subscribed with long-term contracts generally tend to have lower business risk because they are more insulated from changing market conditions and are likely to have more stable cash flows. As shown, GTN faces substantial near-term expirations that (on a percentage basis) are similar to the contract

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[81] Prepared Direct Testimony of Leslie Ferron-Jones, pp. 23-24 (Exhibit No. GTN-26).

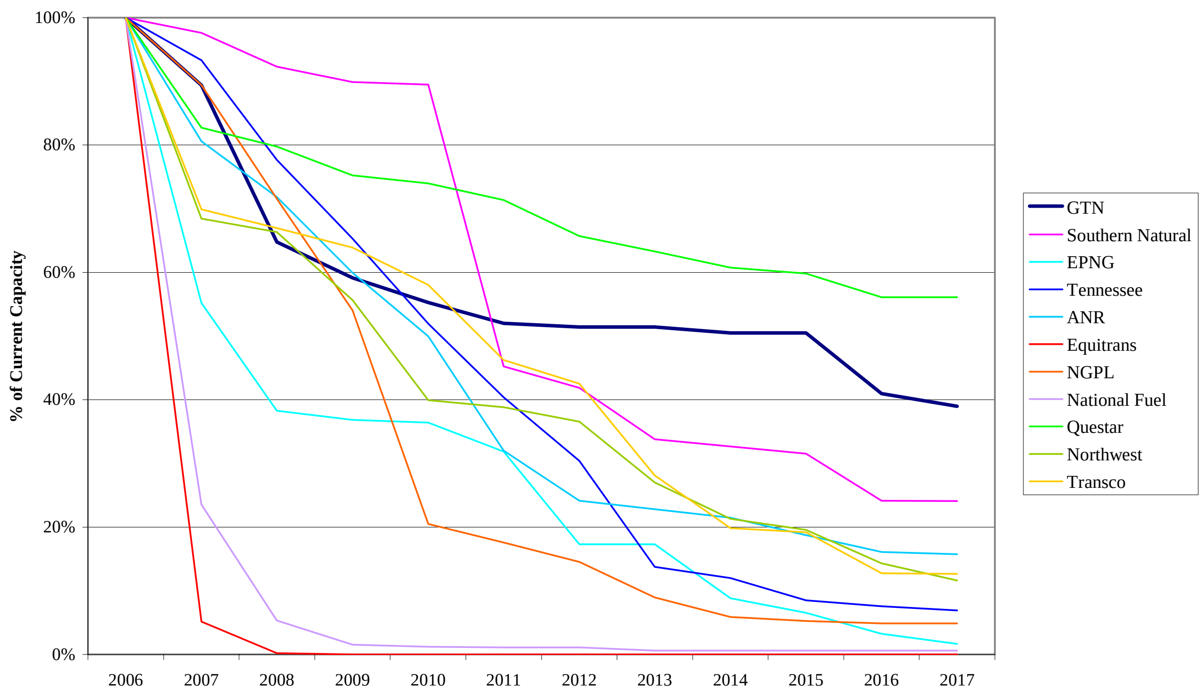
expirations faced by most of the proxy group pipelines, but GTN has a relatively high percentage of its capacity under long-term contracts compared to the pipelines in the proxy group.

In general, nearly all of the pipelines, including GTN, face expiration of roughly 40% of their contractual volumes in the next several years, except for Questar which has a strong contract expiration profile (in part due to the long-term contract it has with its affiliate Questar Gas). None of the pipelines in the proxy group, including GTN, has contract expiration profiles that fully insulate them from changing market conditions in the way that a fully-subscribed pipeline with long-term contracts would be insulated. As I have already discussed, GTN's contract expiration profile is particularly risky given the competitive alternatives available to PG&E and the low capacity values on the Alberta-Malin corridor. Moreover, as I discuss next, a large percentage of GTN's contracts are held by shippers with low credit quality, which makes GTN's contract profile even riskier than is displayed in Figure 8.

In general, Figure 8 is not particularly helpful in determining which pipelines face the highest business risk since almost all of the pipelines in the proxy group have such a significant amount of contract expirations in the coming years. Moreover, the contract expiration data is not informative because it does not capture other important factors. For example, Figure 8 shows Equitrans and National Fuel as having virtually all of their contracts expire in the next two years, but it ignores the fact that a significant amount of the capacity on those pipelines is held by affiliated LDCs that are likely to renew their contracts.[82] Likewise, while 60% of Northwest's capacity will expire by 2010, many expiring contracts will likely be renewed since Northwest does not face significant competition in its primary markets (as described above). Moreover, other shippers are likely to renew due to the access that Northwest provides to Rocky Mountain gas supplies.

Figure 8

% of Capacity under Contract by Year as Proportion to Current Capacity



Sources: Index of Customers, 2nd Quarter, 2006.

Q: Are there other important considerations related to GTN's contract profile?

82 Like National Fuel and Questar, Equitrans is another pipeline that is characterized by a close affiliation with an affiliated LDC. Specifically, Equitable Gas Company is the largest shipper on Equitrans, holding roughly 80% of the contracted transportation capacity. In its most recent 10-K, Equitable Resources reported (with respect to Equitrans) that "In 2005, approximately 76% of transportation volumes and approximately 80% of transportation revenues were from affiliates . . . While all of Equitrans' firm transportation contracts are currently set to expire in either 2006 or 2007, the Company anticipates that the majority of the related volumes will be fully subscribed, and therefore, any resulting decrease in operating income is not expected to be significant."

A: Yes. The credit quality of a pipeline's shippers is another factor to consider in evaluating the risk position of a pipeline. Pipelines with low credit quality shippers are more exposed to shipper bankruptcies. In fact, GTN currently is facing exposure as a result of Calpine's bankruptcy. Calpine holds roughly 160,000 Dth/d of GTN's capacity, and has indicated its intent to repudiate roughly 75,000 Dth/d of that capacity (from Kingsgate to Malin).[83] GTN Witness Kenneth Nichols describes how a large amount of GTN's firm contracted capacity is held by shippers that are not creditworthy,[84] which suggests significant contractual risk for GTN, despite the contract expiration profile that is shown in Figure 8.

VI. CONCLUSION

Q: What are your conclusions regarding GTN's business risk?

A: The evidence demonstrates that GTN has well above-average business risk, resulting from its significant supply and market risks. GTN's supply risk results from the projected flat or declining production profile of the WCSB as well as growth in Canadian gas demand, which together will result in lower U.S. imports from the WCSB. GTN's market risk results from competition to serve California demand from multiple existing basins and pipelines, as well as the pending entry of LNG into California in 2008. These supply and market conditions have significantly devalued GTN's pipeline capacity, making it difficult for GTN to sell pipeline capacity that has become available as shippers have elected not to renew expiring firm transportation contracts. Also factoring into this market risk is the fact that GTN's largest shipper (PG&E) is no longer committed to GTN

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[83] *See* Prepared Direct Testimony of GTN Witness Benjamin K. Johnson, Exhibit No. GTN-12 at pp. 7-8.
[84] *See* Prepared Direct Testimony of GTN Witness Kenneth W. Nichols, Exhibit No. GTN-15 at p. 2.

for the long term and has the ability to explore competitive alternatives to transportation on GTN, including potentially accessing new LNG supplies.

Q: Does that conclude your testimony?

A: Yes.