XIII. NEW GAS SUPPLY-SIDE RESOURCE OPPORTUNITIES

Chapter XII provided an overview of PSE's existing natural gas supply-side resources. This chapter examines potential new gas resource opportunities for PSE. Gas resource portfolio opportunities exist when PSE can vary the structure of its existing capacity resource portfolio. These opportunities arise either when capacity contracts expire or additional capacity opportunities become available. Under some situations, it might also be desirable for PSE to buy out of an existing capacity contract in order to meet PSE's least cost objectives. Over the forecast period, PSE has a number of opportunities to modify the structure of its gas resource portfolio.[1] Although the Northwest Pipeline (NWP) transportation contracts expire over the next 10 years, sponsors are considering new pipeline projects, underground storage expansions are proceeding, conservation continues, and peak shaving resource options could be expanded.

A. Pipeline Capacity

PSE has a number of opportunities to modify its capacity position on interstate pipelines. As detailed in Chapter XII, portions of the NWP contracts expire in 2008, 2009 and 2016. PSE retains the unilateral right to cancel these contracts upon one year's notice. Otherwise, the contracts renew automatically. In essence, the pending expirations, coupled with PSE's renewal rights, create opportunities for PSE to make alternative resource decisions.

Direct-Connect Pipeline Capacity

NWP is the only pipeline connecting directly to PSE's city gates. However, other pipeline projects have developed initial plans to offer transportation alternatives, some of which might connect directly with PSE. To date, those pipeline projects have not generated enough interest to make a project feasible, which leads PSE to believe that a new pipeline delivering into the Company's service area is not likely to happen for some time. However, PSE continues to monitor their progress toward aggregating load, as PSE has some flexibility with respect to the expiration of transportation contracts with NWP and the roll-over terms of those contracts.

[1] These opportunities are permanent capacity changes, as opposed to capacity optimization techniques such as capacity release, interruptible sales, off-system sales, and other portfolio management activities used by PSE to minimize the average cost of gas to its customers.

New pipeline capacity tends to be more expensive than existing capacity. Even expansions of existing pipeline systems tend to be more expensive than the vintage capacity. For example, NWP's recent incrementally-priced Evergreen expansion had a 15-year levelized cost of approximately $0.42 per dth/day, vs. NWP's vintage rate of $0.31. The Federal Energy Regulatory Commission (FERC) has instituted a policy of pricing pipeline expansions incrementally, unless benefits to existing shippers can be demonstrated, with only minor rate impacts.

Even with the higher rates resulting from the completion of the Capacity Replacement Project, PSE expects that NWP will remain the most cost-effective solution for reliable firm service to western Washington. Future expansions of NWP, even though they will be incrementally priced, will also likely be the most cost-effective alternative, until such time as incremental demand aggregates into a single location to justify a new pipeline alternative.

PSE's exclusive reliance on NWP for connection to all supplies of natural gas is a matter of geography, not preference. Understandably, it is difficult for a new pipeline sponsor to compete with the inherently lower cost of expanding or rebuilding infrastructure in an existing right of way. It is especially difficult when the new pipeline must build around or over such hurdles as the Cascade Range or the Columbia River Gorge to access anything but BC-sourced gas.

PSE will evaluate the cost of incremental capacity, weighing other transportation alternatives from a cost and reliability perspective, with economic diversity benefits from access to other supply basins. PSE will be especially mindful of the "reliability in diversity" benefits to be enjoyed by sourcing gas that can get to its system along multiple alternate routes. For threshold economic reasons, PSE may need to rely on NWP to move incremental gas supplies from Sumas to the city gate, but perhaps there can be diversity in how the gas gets to Sumas. To the extent that core loads and/or incremental capacity costs change, PSE believes it is important to maintain this analytical perspective in order to structure its gas resource portfolio on a least cost basis.

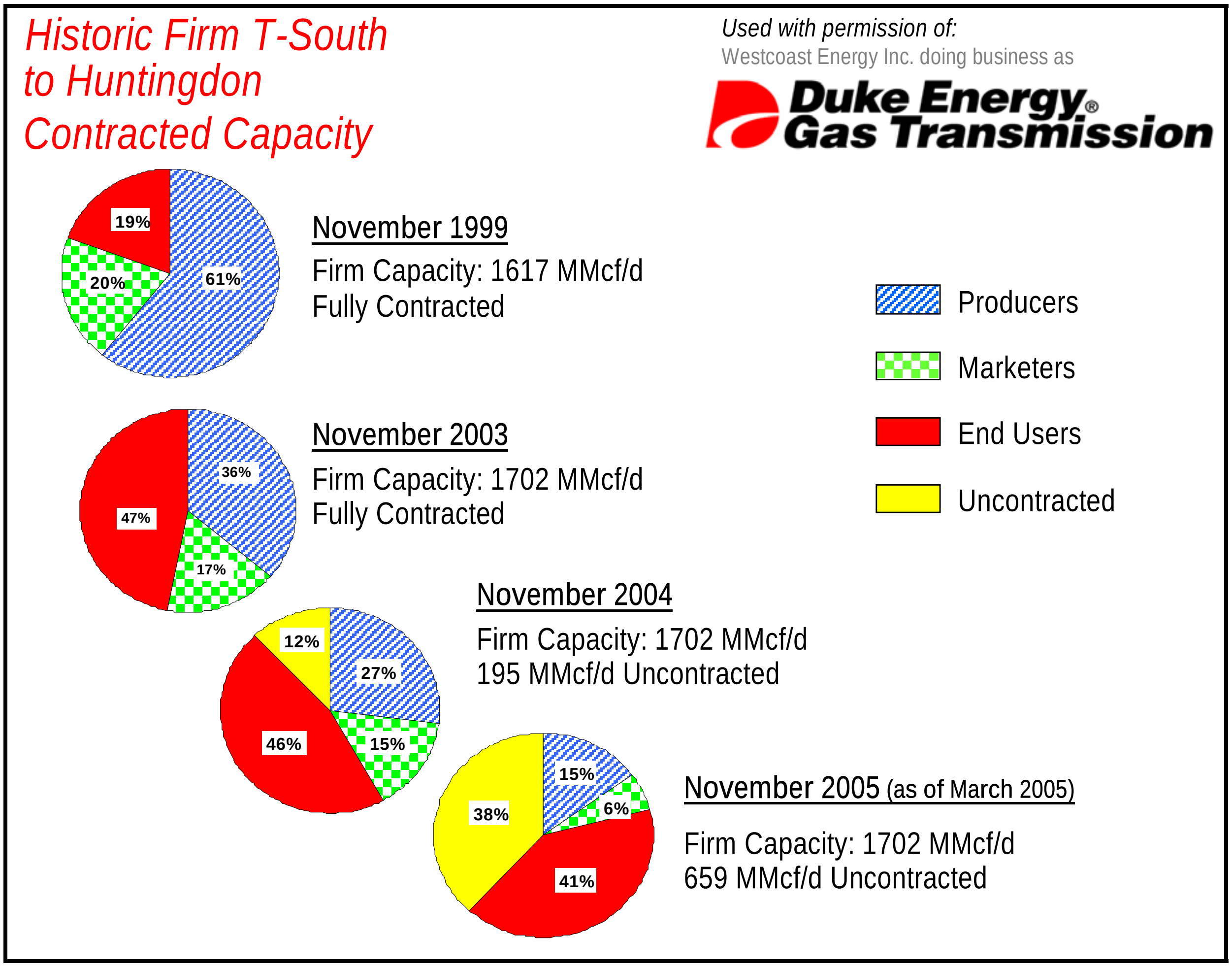
Upstream Pipeline Capacity

In some cases, a trade-off exists between buying gas at one point and buying capacity to enable the purchase of gas at another upstream point closer to the supply basin. PSE has faced this situation with its traditional purchases of gas at the Canadian import points of Sumas and Kingsgate.

PSE holds Gas Transmission Northwest (GTN) capacity from Kingsgate (Canadian border) south to NWP. The Company has had a long-term supply arrangement, through aggregators, with the Alberta Pool at Kingsgate. Transportation costs for upstream pipelines Alaska Natural Gas (ANG) and Nova had been included in the pricing formula. That supply contract terminated in late 2004. In anticipation of the aggregator's decision against renewing or extending the agreement, PSE explored acquiring a) firm supply arrangements at Kingsgate or b) firm supplies at the Alberta Energy Trading Company (AECO), and the acquisition of upstream transportation capacity on ANG and NGTL, if available, or c) some combination of options a and b. In making those decisions, the Company considered a host of factors including price risk, currency risk, pricing and other contract conditions, fixed cost exposure, market liquidity, security of supply issues, other transaction costs, and counterparty creditworthiness. Ultimately, PSE found a very illiquid market at Kingsgate and little or no interest by suppliers in providing firm supply commitments at that point. PSE found that capacity on ANG and Nova was available such that PSE could transport gas from AECO to its city gates. The analysis ultimately led to PSE's acquisition of upstream capacity on both ANG and Nova to allow the Company to acquire gas directly from suppliers at the very liquid trading hub at AECO.

PSE's experience in viewing the Kingsgate market is similar to recent trends on the Westcoast Pipeline system and the probable impact on the Sumas market. In the past two years of annual contract renewals on the Westcoast system, capacity holders (primarily suppliers—Producers/ Marketers of supply) have increasingly allowed their contracts for T-South capacity to expire. It is expected that, as of Nov. 1, 2006, as much as 659,000 Mcf/day or 38 percent of T-South capacity will be uncontracted. See Exhibit XIII-1 below.

Exhibit XIII-1



The producers and marketers of gas supply at Sumas have concluded that it is not in their economic interest to hold T-South capacity, as the cost of such capacity is rarely recouped in the selling price at Sumas. In other words, the spread between Station 2 market price and Sumas price is smaller than the cost of transporting from Station 2 to Sumas. While PSE believes that some producers/marketers will ultimately recontract for T-South capacity, they are only likely to do so if parties commit to new firm supply agreements with pricing terms that remove the risk in holding T-South capacity. As a result, PSE expects that the new pricing norm for long-term firm gas at Sumas will be "Station 2 Index plus the cost of T-South." Short-term gas will likely still be sold at Sumas Index, but that index is likely to be quite volatile due to a much more thinly traded market. During cold spells, selling prices are likely to capture value far greater than the cost of T-South capacity. If this becomes the norm, we would expect that

LDCs—including PSE—would be driven to acquire the unsold T-South capacity and contract for supplies at Station 2 to ensure the continued reliability of access to firm supply.

PSE initiated its response to this market development by acquiring 40,000 Dth/d of capacity on Westcoast Pipeline from Station 2 to Huntingdon, BC (Sumas), starting November 2003. PSE can take advantage of a growing supply market at Station 2 with this transportation capacity, minimizing its cost and risk by contracting for a portion of this upstream transportation, and serving as a hedge against potential price spikes at the Sumas market.

As the availability of gas at Sumas declines, PSE expects it will acquire additional T-South capacity to access firm supplies at Station 2. In addition, PSE will explore other opportunities to access firm gas supply that can be delivered to the city gate through the Sumas interconnect.

Terasen Gas, formerly known as BC Gas, is offering firm bundled capacity from the interconnection point of their facilities in south-eastern BC to the ANG/Nova system through the southernmost portion of the Westcoast system to the Sumas interconnect with NWP. This route, along with additional ANG and Nova capacity, could be used to move incremental supply from the liquid trading hub at AECO to the PSE system. While not inexpensive, such an alternative would increase geographic diversity of supply and reduce reliance on BC-sourced supply from what it would otherwise be.

PSE will continue to evaluate its upstream transportation requirements and opportunities, and evaluate its position to ensure a balance of market diversity, liquidity, volatility and least cost.

B. Storage Capacity

PSE has a number of opportunities to modify its storage capacity positions over the next eight years. As detailed in Chapter XIII, the Jackson Prairie leased capacity expires in 2006. The Clay Basin contract continues through 2013 and 2020.

A capacity expansion is currently underway at Jackson Prairie, anticipated to add an additional 900,000 Dth of storage capacity to the facility each of the next eight years, eventually expanding the total capacity by 10,500,000 Dth by the summer of 2012. Of this capacity, 40 percent will be cushion gas—gas that is injected and used to maintain reservoir pressure. The remaining 60 percent—or 540,000 Dth each year for a grand total of 6,300,000 Dth—will be used to provide working storage capacity. PSE holds the right to use one-third of this working capacity or 2,100,000 Dth when complete.

While the exact timeframe for the expansion of the Jackson Prairie deliverability has not yet been determined, PSE anticipates the owners will expand the deliverability of the project by as much as 300,000 dth/day (100,000 dth/day for PSE) before the winter of 2012-2013. PSE is also analyzing the benefits of expanding deliverability as early as 2008. Jackson Prairie deliverability is likely to be the least cost way of meeting PSE's firm load growth.

C. Peaking Resources

PSE's recent experience with the development of its Gig Harbor Liquified Natural Gas (LNG) peaking facility has provided insight into the new technology, operational efficiency and cost effectiveness of satellite LNG peaking. LNG is easier to blend into the natural gas stream than propane-air mix.

PSE will study the potential to incorporate satellite (using trucked-in LNG) LNG technology and conventional (using LNG liquefied on-site from pipeline gas) LNG peaking into the long-term resource mix.

PSE will also consider contracting for conventional LNG peaking service from a third-party provider, which recently received preliminary authorization to construct a plant in the region. LNG peaking and a cost-effective firm redelivery/exchange service will be available for an interim period beginning in 2007 (or 2008 depending on the timing of final authorizations) to serve as a bridge to other long-term resources.

D. Gas Supplies

The Company manages its supply portfolio to maintain supply diversity, and the pricing terms reflect at least three regional markets: the U.S. Rockies, British Columbia, and Alberta. Over long periods of time, a tendency exists toward equilibrium pricing among the three regions. Over shorter timeframes, however, one basin will be lower in cost than the others—a difference that can be more pronounced on a daily basis. PSE's capacity rights on NWP provide some flexibility in buying from the lowest cost basin. This arbitrage opportunity can mitigate price volatility, and serves to mediate prices between the various supply basins.

PSE has always purchased its supply at market hubs or pooling points. In the Rockies, the transportation receipt point is Opal, but alternate points, such as gathering system interconnects with NWP, allow for some purchases directly from producers as well as from gathering and processing firms. In fact, PSE has a number of supply arrangements with major producers in the Rockies, giving the Company the ability to purchase supply at or close "to the wellhead," or point of production.

The addition of capacity on Westcoast and ANG/Nova to the PSE portfolio have increased PSE's ability to access supply "at the wellhead" in Canada as well.

From a supply-planning perspective, continued diversification of its natural gas purchases among the three supply basins provides some measure of reliability and price protection for PSE by avoiding a concentration in any single market. For this reason, PSE expects to maintain this approach to contracting for gas supplies in the Rockies, British Columbia and Alberta.

Pipeline projects add capacity in a stepwise fashion, while load growth and supply production increases tend to happen more gradually. New pipeline projects can suddenly increase the take-away capacity from one supply basin, shifting the supply-demand dynamic across the network. As a result, large price shifts can result from a pipeline expansion project. While the pricing data illustrates the relative equilibrium among the western basins, the imbalance lies between these basins and the market areas. When that differential becomes large enough and persists over time, market participants contract for new capacity, and the new pipeline capacity is built. This tends to re-balance the market.

Commercial Relationships, Market Trends and New Resources

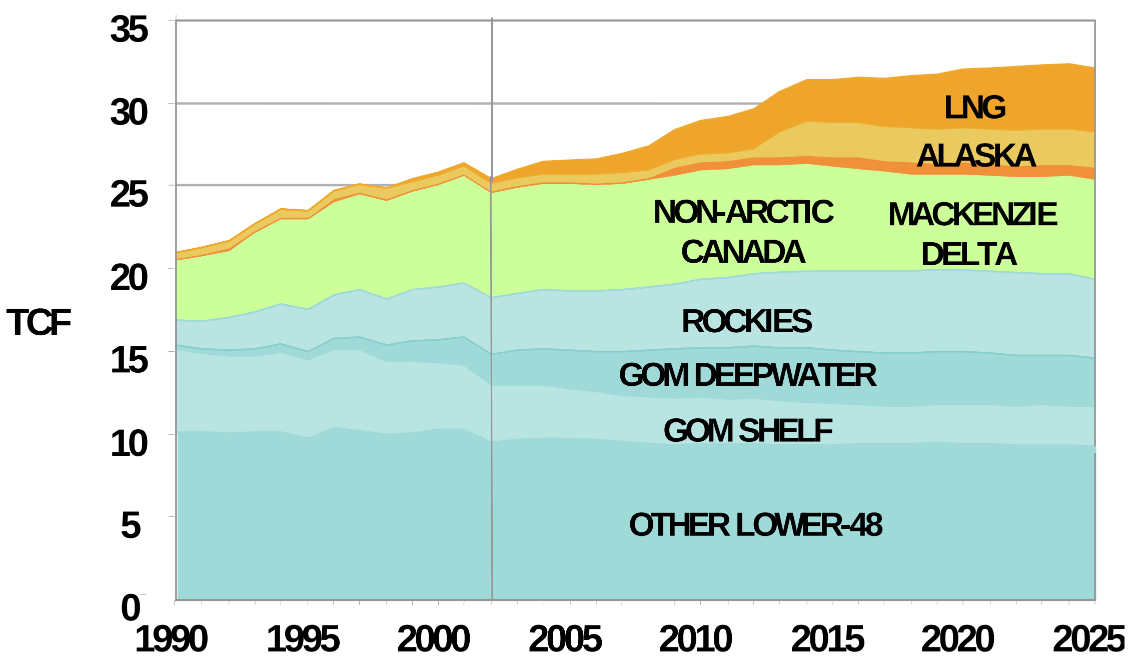
The variables associated with managing PSE's natural gas supply portfolios include physical supply security, commodity pricing (including volatility), and commercial relationships. Historically, PSE has sought to diversify its overall supply portfolios by dividing its supplies among its three primary supply regions – Rockies, Alberta, and British Columbia – and further dividing its commercial relationships among as many creditworthy counterparties as possible. The growing economy (demand for natural gas) and the fear of flat to declining year-on-year domestic and Canadian natural gas production creates significant concern for both supply security and pricing certainty. It is generally believed that the current supply scarcity in the

North American market will continue and possibly become worse before new sources of natural gas can be developed. It is generally believed that this shortfall—absent contributions from Arctic or Alaskan gas, or from LNG imports—will reach between 8 and 10 Bcf per day by 2010. Therefore, it is very likely that the price of natural gas will remain high and be subject to significant market volatility.

Supply Overview

From a supply standpoint, the major oil and gas companies have moved their exploration activities offshore. These companies, along with others, have developed large, “stranded” gas reserves for which they are seeking markets. The United States is the largest market, where the addition of new gas-fired electrical generation, along with other load growth has created a projected 2010 natural gas shortfall of 8 to 10 Bcf/d.

Exhibit XIII-2
AGA’s Forecast of New Resources



Whether real or perceived, an anticipated supply shortage has driven natural gas prices to high levels, created a great deal of pricing volatility in the market, and prompted conservative market pricing practices. Further, it must be remembered that costs do not establish market prices until there is an oversupply. Major suppliers and producers are moving their planning prices upward, but not above $4.00/MMBtu. Instead, they are improving their balance sheets by reducing debt and buying back stock.

Marketplace Trends

In response to increases in demand and supply uncertainty, the natural gas marketplace has experienced high prices coupled with pricing volatility. Combined with the increased counterparty credit requirements (an outcome of the energy crisis), the majority of suppliers and producers have consistently avoided long-term fixed price supply arrangements in favor of short-term sales arrangements. For the most part, only producers with secure sources of production have been willing to consider agreements of up to 5 years, but only if sales agreements have “market mean reverting” price structures, and any term beyond 3-4 years must have corporate approvals. The most prevalent of these pricing mechanisms incorporate indexing to published monthly market indices.

Until recently, only a handful of suppliers and financial institutions, wanting to “lock in” the current high gas prices, were willing to discuss the development of long-term, “fixed price” contracts. Even tentative discussions about fixed pricing mechanisms were very infrequent. No supplier was willing to sell its gas at below its forward-market price curves, and even then a healthy risk premium was required. Only recently have a handful of the largest producers been willing to explore long-term fixed price contracts.

In the past 12 months, two potential counterparties have expressed a willingness to enter into discussions of long-term fixed priced supply arrangements on an exploratory basis. Both counterparties suggested that their willingness to discuss long-term arrangements was a manifestation of a desire to “hedge” their LNG and/or their Alaskan or Frontier pipeline projects. A concern that they and others have is that the introduction of new supplies of natural gas into the currently constrained North American marketplace may drive the current market price downward and they are anxious to lock-in today’s prices.

Along with the willingness to explore longer-term contracts came an implicit willingness to modify current industry credit requirements. To date, PSE has seen no relaxation or modification of industry credit requirements. Without this, our long-term, fixed-price natural gas discussions will remain only “exploratory” in nature and the natural gas marketplace will remain focused on relatively short-term natural gas transactions.

New and Alternate Supply Resources

Recognizing that the current high and volatile pricing is largely a function of the supply scarcity, PSE has and continues to carefully monitor projects and resources that will provide for gas supply surplus. To this end, the two areas of major focus include new Alaskan and frontier gas pipelines and the importation of LNG.

Two major pipelines have been proposed to transport gas from the Arctic to the North American markets. The Alaska Natural Gas Transmission System is intended to transport natural gas 3,500 miles from the North Slope through Canada and on to Chicago. This $20 billion project is designed to provide 4.5 Bcf/d of natural gas between 2013 and 2015. The second major pipeline, the Mackenzie Valley Pipeline is intended to transport natural gas 1,300 kilometers from the Tablus, Parsons Lake and Niglintgak fields to the northern border of Alberta. This $3.6 billion project is designed to deliver 800 million cubic feet per day as early as 2010. Unfortunately, both of these attractive projects are too far out into the future to provide relief to the current supply-scarce marketplace.

The most promising of the identified supply scenarios is the utilization of existing and the development of incremental LNG regasification terminals. At today's prevailing gas prices, LNG can be competitively transported, stored, and marketed. There are four major existing LNG regasification terminals operating in the United States (Everett, Trunkline LNG, Elba Island, and Cove Point). Throughout 2004 these terminals averaged a throughput of approximately 2.5 Bcf/d. They have the ability to provide approximately 4Bcf/d, and are capable of providing between 3 and 4 percent of the current natural gas requirement.

Major oil and gas companies recognize that LNG can provide a significant contribution to alleviating the current supply scarcity, and they see an opportunity to market their "stranded" reserves. In response, these companies are pursuing the development of additional regasification terminals. To date, over 50 terminals have been proposed, with at least seven to be located in Oregon, Washington and British Columbia. However, given the existing anticipated 8 to 10 Bcf/d shortfall, it is likely that only 4 to 6 additional regasification terminals will be needed in the near future.

The LNG Value Chain is made up of four discreet parts: Exploration and Production (feedstock), Liquefaction, Transportation, and Regasification. An approximate breakdown of the capital and production costs for a 1 Bcf/d LNG Value Chain is shown in Exhibit XIII-3.

Exhibit XIII-3
LNG Value Chain

Value Chain Component	Capital Cost/Bcf/d ($Billions)[2]	Market Cost Required ($/MMBtu)[3,4]
E & P (Feedstock)	1.5	$0.5 to $1.0
Liquefaction	2.0	$0.8 to $1.2
Transportation	2.0	$0.3 to $1.8
Regasification	0.5	$0.3 to $0.65
Total	$6.0	$2.10 to $4.65/Mcf

The estimated cost of LNG production is well within the current and anticipated market price range of natural gas. The development of individual trains is typified by low exploration and technology risks, and by high capital cost. These projects are best described as financial transactions that will require the following:

- An experienced sponsor with a strong balance sheet
- A secure source of natural gas
- A large immediate market or an extensive infrastructure that is capable of consuming the entire output of an LNG regasification plant
- Long-term off-take agreements that will support the project financing costs

The siting of domestic regasification terminals will be challenging. To capture the economies of scale, the terminals must be large. These large "supply building blocks" will require bigger markets that can swallow the design output "whole." Ideal sites include the Gulf of Mexico (with its takeaway transportation hub), Southern California, and parts of the Eastern Seaboard. Fundamentals models of the North American gas market all indicate that the introduction of incremental imported LNG at any location will tend to lower or at least stabilize prices

[2] Turkelson, Don. "LNG to North America's Gulf Coast" (SRI).
[3] Foss, Michelle Michot. "LNG Development in a Post 9/11 World" (SRI 2004). Ms. Michot is the Executive Director of the Institute for Energy, law & Enterprise at the University of Houston Law Center.
[4] Second set of numbers came from a Ziff Presentation "North American Gas Strategies 1st Quarter 2005" made in PSE's offices on 3 March, 2005. The Ziff numbers are expressed in US $/Mcf

throughout the market as the supply growth rebalances the market. Additionally, depending on location, imported LNG could have the effect of displacing some of the current supply for a given region—freeing up that supply to serve other markets. For example, it is generally assumed that LNG imports into the southern California market would displace some supplies from Alberta, thus causing a relative decline in pricing of Alberta supplies as they attempt to find a home in other markets. Irrespective of location, import LNG regasification projects hold the greatest potential for providing supply scarcity and price volatility relief in the near term.

For analysis purposes, PSE has considered two hypothetical regional LNG import regasification terminals: "South LNG Import"—connected to the NWP system south of PSE's service territory and assumed to require incremental NWP capacity construction north to PSE's service territory, and "North LNG Import"—connected to the Westcoast system in BC and requiring utilization of Westcoast T-South capacity and NWP capacity to provide delivery to the PSE system. In each case it has been assumed, absent more definitive information from project developers, that the LNG supply itself would be priced at the AECO index plus a small demand charge (at the regasification plant outlet/pipeline interconnect).

With respect to planning future gas purchases from the various supply basins, PSE will diversify its portfolio to match the transportation take-way capacity it holds at the primary receipt points in its long-term pipeline transportation contracts. Over time, as the market differentials spur pipeline capacity expansions, PSE could have an opportunity to diversify to other supply basins. However, the expansions might also serve to bring prices closer together.

In summary, the pipeline transportation contracts held by PSE position it well to maintain access to adequate gas supplies in producing areas well-positioned for further development. These supplies will likely remain price competitive due to the focus on development of these reserves. PSE finds itself in a strong position to seek additional pipeline capacity when needed to meet incremental load requirements with reliable and economical gas supplies.

Therefore, PSE's long-term natural gas acquisition strategy is as follows:

- Establish master enabling agreements with as many creditworthy entities as possible.
- Improve supply security by entering into long-term, index-based contracts across multiple supply regions and with a diversity of index-based pricing structures.

- Explore the potential development of long-term “fixed price” contracts and incorporate them into PSE’s portfolio as appropriate.
- Monitor the development of new or alternative natural gas resources (e.g., coal bed methane, LNG importation, landfill gas, new pipelines, etc.).