

# Dynamic Pricing Model: Study of Natural Gas Alternatives for the Pacific Northwest as they may be met by the Jordan Cove Energy Facility

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# 1 Executive Summary

## Introduction

ICF was retained by the Jordan Cove Energy Project (JCEP) to provide an assessment of the market dynamics influencing natural gas prices in the Pacific Northwest<sup>1</sup>, and the potential impact of the proposed Jordan Cove LNG import facility on regional prices. This report discusses Pacific Northwest price relationships to the North American market as a whole and among pricing points within the region.

The Base Case projection, which excludes the Jordan Cove facility, is used as a starting point for scenario analysis in a study of the potential impacts. The report also includes a discussion contrasting prices under five alternate Pacific Northwest gas market infrastructure scenarios. The scenarios examine the potential impact of the Jordan Cove facility, several proposed new gas pipelines, and various Jordan Cove and pipeline combinations.

## Review of the Pacific Northwest Natural Gas Market

Annual Pacific Northwest gas consumption has fluctuated in the last 10 years ranging from a high of 521 Bcf in 2001 to a low of 420 Bcf in 1997 and 2002. Industrial demand decreased in 2000 and 2001 in response to increases in natural gas prices corresponding with the California Energy crisis. As of 2006, total end-use natural gas consumption in Washington and Oregon was approximately 470 Bcf. Currently, core gas consumers (which includes residential and commercial customers) account for about 40 percent of the market, while industrial and electric power consumers account for about 30 percent each.

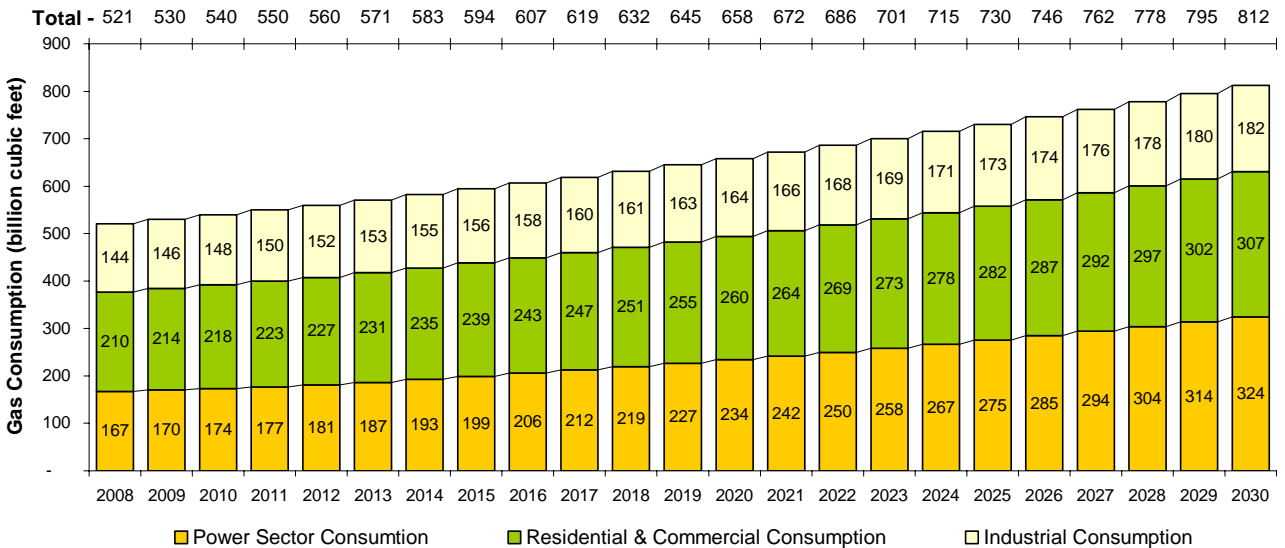
Based on forecasted growth rates from the Northwest Gas Associated (NWGA), extrapolated out to 2030, total consumption in the Pacific Northwest is projected to increase at a rate of about 2 percent per year, from 521 Bcf in 2008 to 812 Bcf by 2030 (Exhibit 1.1). While consumption in all sectors is expected to increase, over half of the increase is from increased gas-fired generation. Core consumption accounts for about one-third of the consumption growth, while increases in industrial gas consumption are relatively modest.

The Pacific Northwest imports essentially all of its natural gas supplies via two interstate pipelines: Northwest Pipeline and Gas Transmission Northwest (GTN). Most of the region's gas consumption is served by Northwest Pipeline. Historically, Oregon and Washington have been dependent upon gas from the Western Canada Sedimentary Basin (WCSB) and the U.S. Rockies. Canadian gas can be imported into the region via either the Northwest or GTN pipelines. Rockies supplies are accessible via Northwest Pipeline. In 2006 the Pacific Northwest imported over 1,000 Bcf of natural gas or an average of about 2.8 Bcf per day. About 88 percent of these imports came from Canada, while the remaining 12 percent came from the Northern Rockies. As a percentage of Pacific Northwest imports, Rockies supplies have been growing since 2000. Much of the gas imported on GTN is simply "flowing through" the Pacific Northwest, on its way to California and Nevada markets. Historically, between 50 and 55 percent of all gas imported into the region was subsequently exported.

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<sup>1</sup> Throughout this report, the states of Oregon and Washington are collectively referred to as the Pacific Northwest.

## Exhibit 1.1: Projected Natural Gas Consumption for the Pacific Northwest (Bcf per Year)



### Key Assumptions for the Base Case and Alternate Projections

In order to analyze natural gas price and basis impacts of various gas supply infrastructure options for the Pacific Northwest, ICF created a complete North American natural gas market Base Case projection, based on the Gas Market Model (GMM) March 2008 Base Case, with modifications to match the Pacific Northwest consumption trends discussed above. ICF's GMM modeling framework projects gas supply, demand, transport and prices on a monthly basis from 2008 through 2030. The Base Case did not include any new pipelines or LNG facilities for the Pacific Northwest.

In addition to the Base Case, ICF developed five alternate scenarios to help quantify market impacts and potential benefits to Pacific Northwest consumers of various gas infrastructure supply options. The five alternate scenarios are:

- (1) **Jordan Cove LNG Import Terminal and the Pacific Connector Gas Pipeline. (*Jordan Cove 100*)** This case adds the Jordan Cove Energy Project LNG import terminal with a regasification capacity of 1 Bcf per day in June 2012. This scenario also adds the Pacific Connector from Coos Bay, Oregon to Malin, Oregon in-service in June 2012 at a capacity of 1 Bcf per day. This case limits direct deliveries to Oregon consumption markets to 100 MMcf per day to reflect current pipeline capacities.
- (2) **Jordan Cove LNG Import Terminal and the Pacific Connector Gas Pipeline. (*Jordan Cove 300*)** This is identical to scenario (1) except capacity to deliver directly to Oregon markets are increased to 300 MMcf per day representing enhancements to Northwest Pipeline's Grants Pass Lateral south of Eugene, Oregon.
- (3) **Ruby Pipeline (*Ruby*).** This case adds the Ruby Pipeline from Opal to Malin at a capacity of 1.2 Bcf per day with in-service June 2011. There is no Pacific Northwest LNG terminal in this scenario.

- (4) **Ruby Pipeline and Palomar Pipeline (*Ruby / Palomar*)**. This case adds the Ruby Pipeline under the same size and timing as in scenario 2 above, plus the Palomar Pipeline from an intersection with Gas Transmission Northwest near Kent, Oregon to Molalla, Oregon, in-service in June 2013 at a capacity of 1 Bcf per day. There is no Pacific Northwest LNG terminal in this scenario.
- (5) **Jordan Cove LNG Import Terminal, the Pacific Connector Gas Pipeline, and Ruby Pipeline (*Jordan Cove / Ruby*)**. This case adds the Jordan Cove LNG terminal, the Pacific Connector Pipeline, and the Ruby Pipeline with the same size and timing as scenarios 2 and 3 above.

## Impacts on Gas Price and Basis Trends

The North American natural gas market has undergone a fundamental shift that started at the beginning of this decade. Throughout most of the 1990s, an excess of productive capacity created a “gas bubble” in the North American natural gas market. As a result, gas prices were relatively low and stable during the 1990s, with prices at Henry Hub (considered the benchmark pricing point for the U.S.) generally ranging between \$2 and \$3 per MMBtu. Since 2000, the surplus of productive capacity has disappeared and the supply and demand balance for natural gas has become much tighter, creating a new pricing regime. Since 2005, Henry Hub prices have averaged over \$6.50 per MMBtu.

In general, the Pacific Northwest gas price indices (Kingsgate, Sumas, Stanfield, and Malin) have followed the same upward trend as North American gas prices. Exhibit 1.2 and Exhibit 1.3 show the historic and projected average annual gas prices at Sumas and Malin for the Base Case and the five alternate scenarios. Sumas is a close proxy for natural gas price trends in the Pacific Northwest population centers along the West Coast, between Seattle and Portland. With the exception of 2005, when prices spiked due to Hurricanes Rita and Katrina, gas prices at both Sumas and Malin have been moving up steadily since 2002.

The Base Case projection has prices at both Sumas and Malin climbing to about \$12 per MMBtu by 2020<sup>2</sup>. All of the alternate scenarios reduce prices at Sumas below the Base Case levels. The Jordan Cove / Ruby case has the lowest prices for both Sumas and Malin, reducing prices by an average of about 60 cents per MMBtu between 2011 and 2020, compared to the Base Case. Adding Ruby Pipeline alone has relatively little impact on Sumas prices; this case lowers Sumas prices by an average of only 24 cents between 2011 and 2020. Sumas prices drop by much more in the cases where natural gas infrastructure is added directly into western Oregon or Washington such as the cases when either Jordan Cove LNG or the Palomar Pipeline is added.

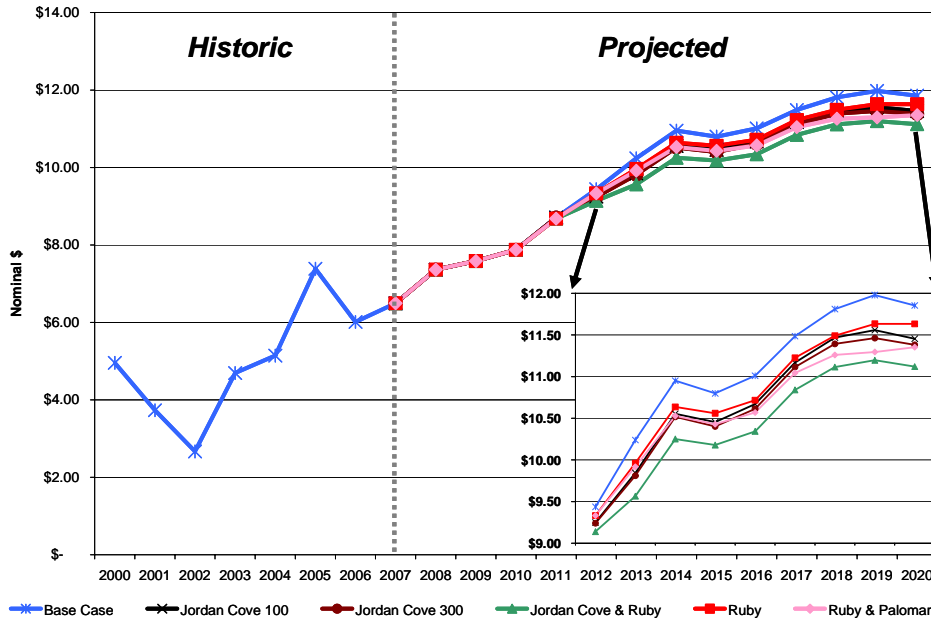
Another way to examine gas prices is to look at the difference in prices, or “basis”, between the Pacific Northwest and Henry Hub. The basis between Henry Hub and the Pacific Northwest indices have been negative (that is, Pacific Northwest have been lower than Henry Hub) since 2002. However, since 2006 the basis differential between the Pacific Northwest indices and Henry Hub has been narrowing, as Pacific Northwest prices rise closer to those at Henry Hub, as shown in Exhibit 1.4 and Exhibit 1.5. In the Base Case, which assumes no additional natural gas infrastructure to the Pacific Northwest, the increasing basis trend continues through to 2020. In the Base Case, basis to the Pacific Northwest turns positive (that is, prices are higher than at Henry Hub) by 2012 and reaches 30 to 40 cents per MMBtu by 2020.

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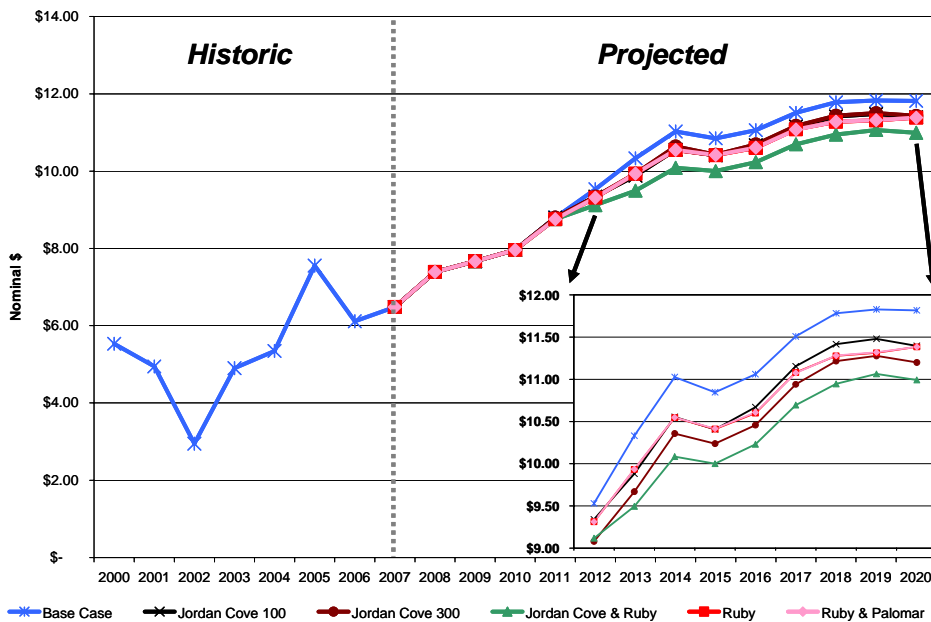
<sup>2</sup> Long-term price projections to 2030 are discussed in the Appendix. Beyond 2020 a variety of other factors, most notably the development of arctic gas supplies, strongly influence regional price and basis. The price graphs were limited to 2020 for clarity. Tabular results for all time periods are in the Appendix.

All five other alternate scenarios reduce the Pacific Northwest to Henry Hub basis relative to the Base Case. The greatest reduction is in the Jordan Cove / Ruby case, where basis averages 20 to 35 cent per MMBtu below the Base Case between 2011 and 2020. While the case with Ruby Pipeline alone has significant impact on Malin basis, it has very little impact on Sumas.

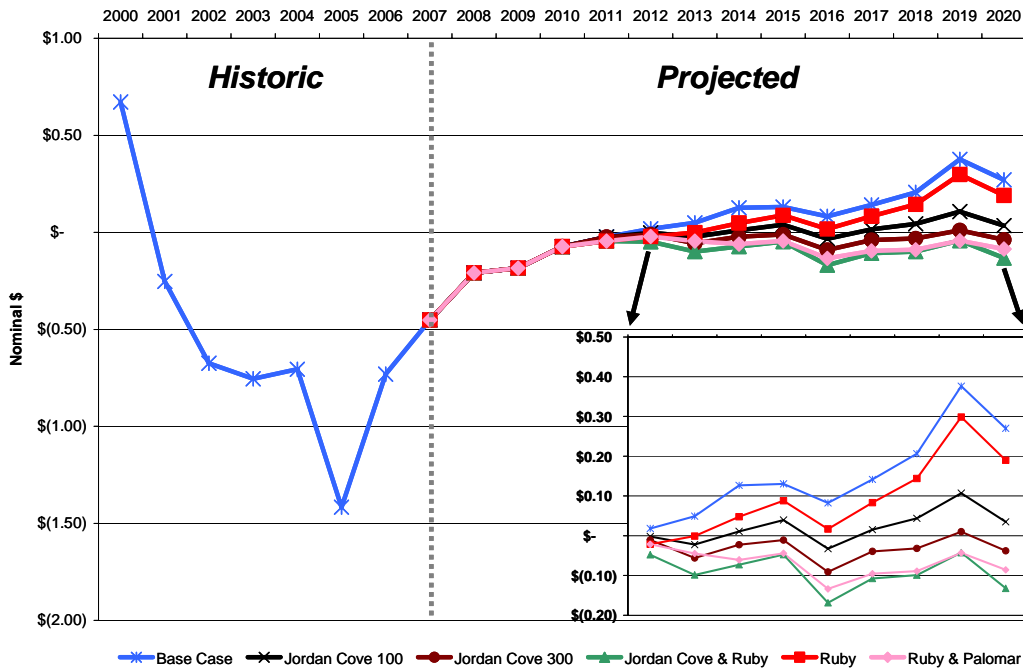
**Exhibit 1.2: Historic and Projected Sumas Natural Gas Price by Scenario 2000-2020 (\$'s per MMBtu)**



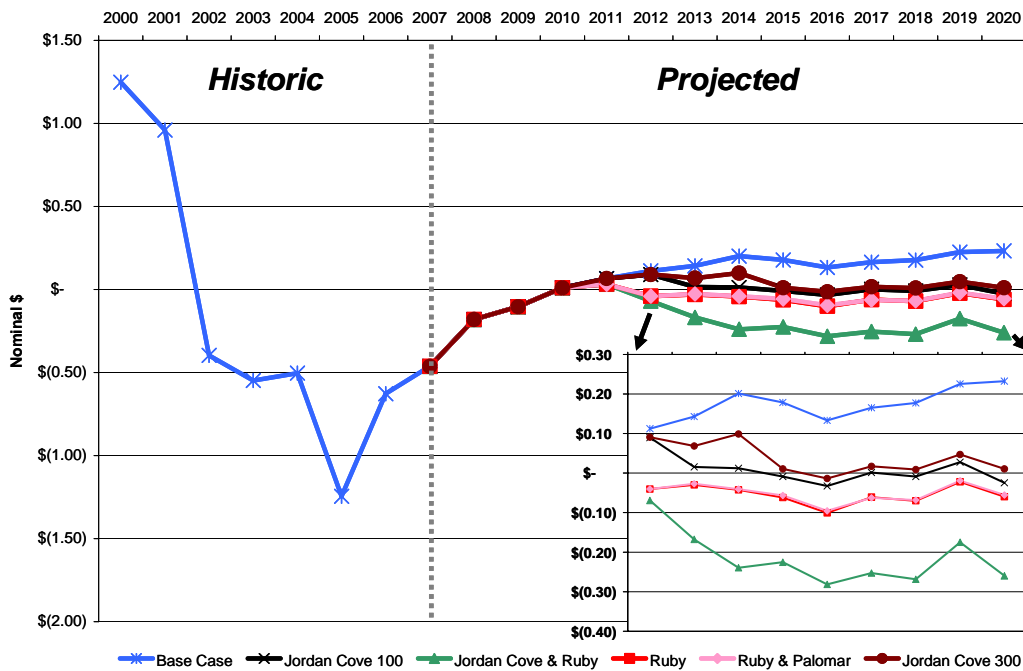
**Exhibit 1.3: Historic and Projected Malin Natural Gas Price by Scenario 2000-2020 (\$'s per MMBtu)**



**Exhibit 1.4: Historic and Projected Sumas to Henry Hub Average Annual Basis by Scenario 2000-2020 (\$'s per MMBtu)**



**Exhibit 1.5: Historic and Projected Malin to Henry Hub Average Annual Basis by Scenario 2000-2020 (\$'s per MMBtu)**



## 2 Review of the Pacific Northwest Natural Gas Market

### Introduction

This section provides a brief overview the Pacific Northwest<sup>3</sup> natural gas market. Current natural gas pipeline and storage infrastructure,<sup>4</sup> historical gas consumption, and regional imports/exports are discussed.

### Existing Natural Gas Market Infrastructure

The Pacific Northwest imports essentially all of its natural gas supplies via two interstate pipelines: Northwest Pipeline and Gas Transmission Northwest (GTN) (Exhibit 2.1). Most of the region's gas consumption is served by Northwest Pipeline. GTN is mainly a conduit for gas supplies to California and Nevada; however some gas supplies are delivered off of GTN to serve regional consumption either directly or through interconnects with Northwest Pipeline.

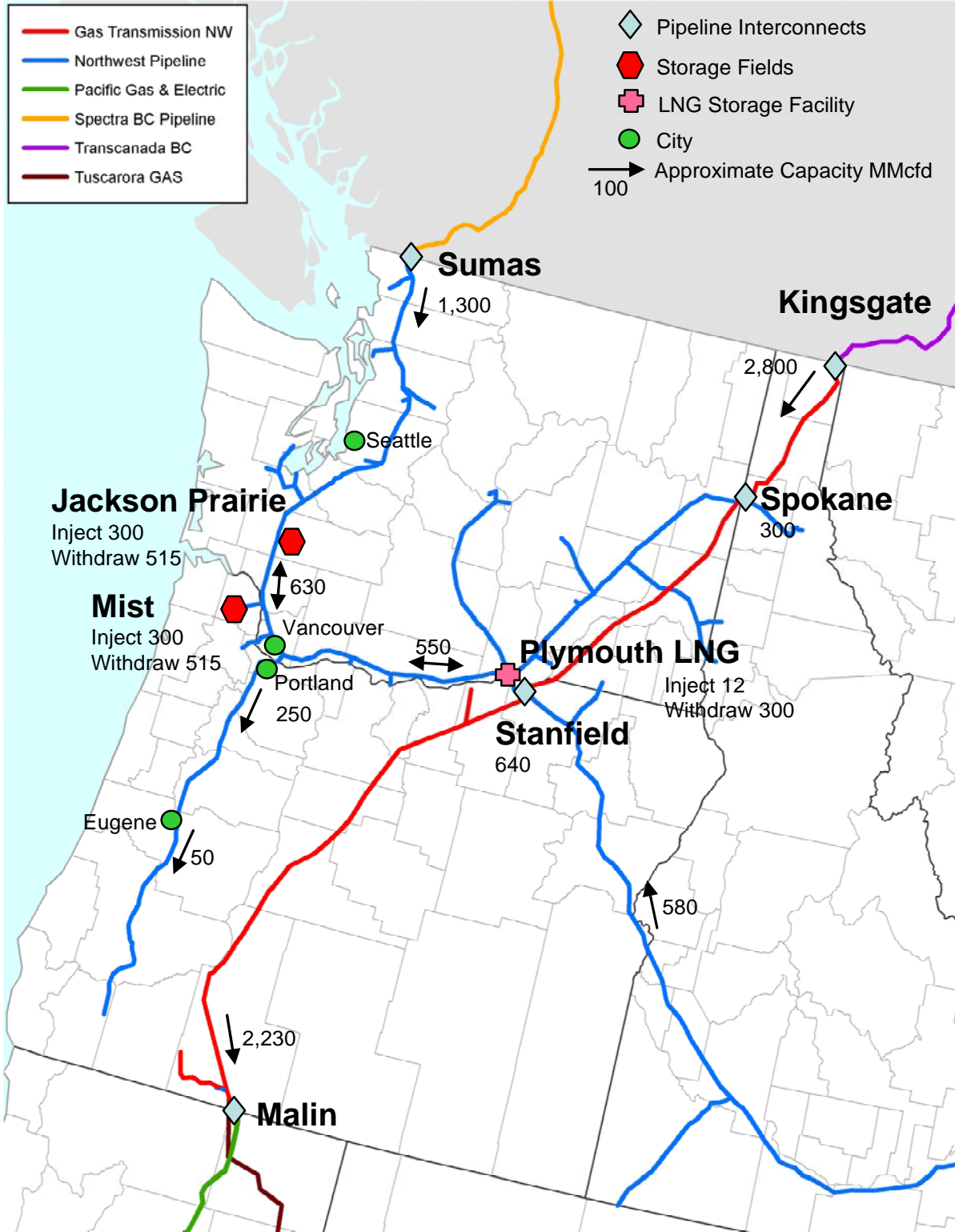
There are two conventional natural gas storage fields in the region and one LNG peak storage facility. The Mist field is a 16 Bcf storage field in Columbia County, Oregon near Vancouver and the Jackson Prairie field is a 23 Bcf storage field in Lewis County, Washington. The Jackson Prairie field is in the process of yearly expansions and will have a capacity of 25.4 Bcf by 2010. There is also a liquified natural gas (LNG) peaking storage facility near Plymouth, Washington.

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<sup>3</sup> For this report the Pacific Northwest is defined as the states of Washington and Oregon.

<sup>4</sup> More detailed discussion of existing and proposed regional pipeline, storage, and liquefied natural gas (LNG) infrastructure is discussed in the Appendix. There are currently no existing LNG import terminals in the Pacific Northwest.

**Exhibit 2.1: Pacific Northwest Natural Gas Infrastructure**

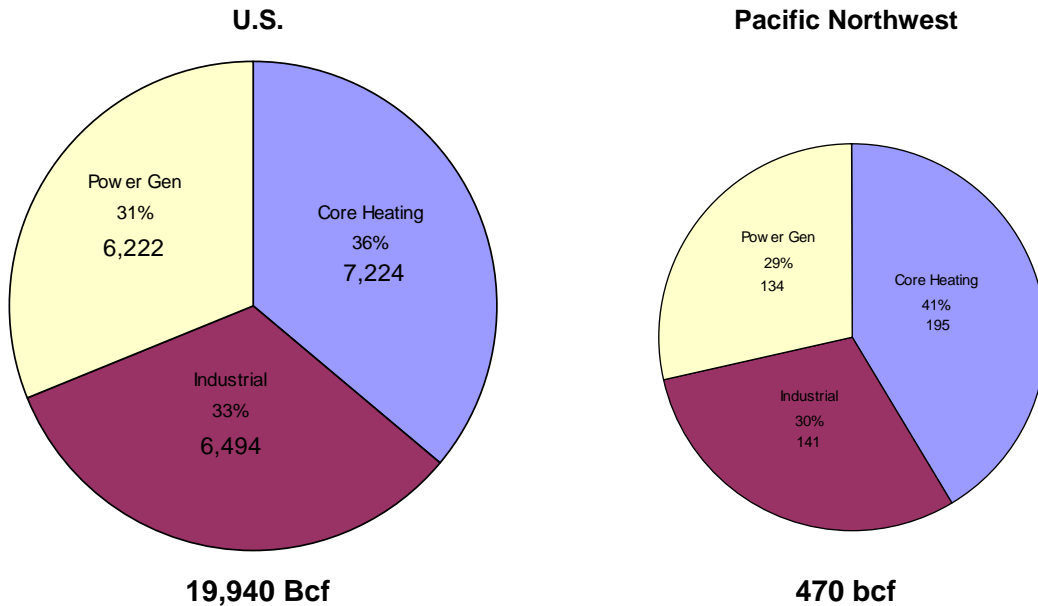


Source: Pipeline Company Electronic Bulletin Boards (EBBs) and other Public Sources.

## Historical Natural Gas Consumption

Total end-use<sup>5</sup> natural gas consumption in Washington and Oregon for 2006 was approximately 470 Bcf (Exhibit 2.3), averaging about 1.3 Bcf per day for the year, or roughly 2.3 percent of total U.S. consumption of 19.9 Tcf.

**Exhibit 2.2: U.S. and Pacific Northwest 2006 Natural Gas Consumption by Sector (Bcf)**

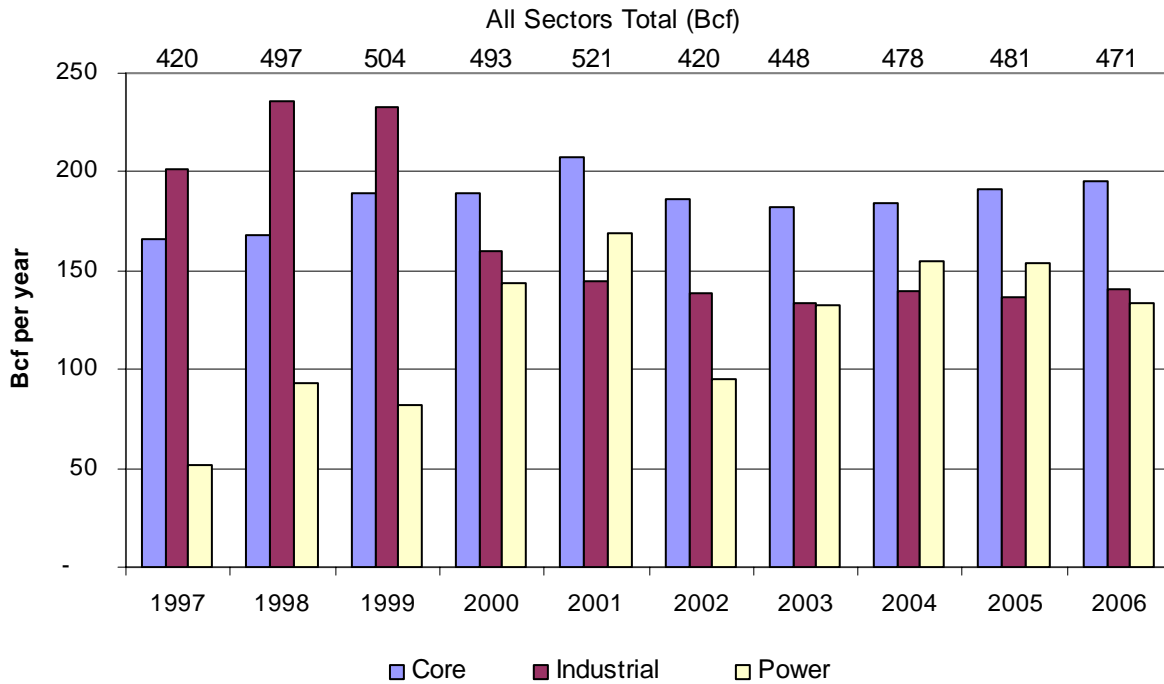


The market shares of the various gas consuming sectors illustrate regional differences as compared to national averages. Pacific Northwest gas consumption for core space and water heating customers (both residential and commercial) accounts for 41 percent of the market share, while the U.S. national average is lower at 36 percent. This is expected in northern regions like the Pacific Northwest due to climate. The market shares of power generation and industrial sector gas consumption are slightly lower than national averages.

Historical gas consumption by sector is shown in Exhibit 2.3. Annual Pacific Northwest gas consumption has fluctuated in the last 10, years ranging from a high 521 Bcf in 2001 to a low of 420 Bcf in 1997 and 2002. Much of the variation is due to fluctuations in industrial demand. Prior to 1999, the industrial sector was the largest consumer of natural gas in Oregon and Washington. However, industrial demand decreased in 2000 and 2001 in response to increases in natural gas prices, with the sharp drop corresponding to the California Energy crisis. Industrial gas consumers reduced their gas use by 38 percent from 232 Bcf in 1999 to less than 145 Bcf in 2001.

<sup>5</sup> Excludes Pipeline Fuel.

**Exhibit 2.3: Pacific Northwest Historical Gas Consumption by Sector 1997 to 2006**



Source: Energy Information Administration

Residential and commercial consumers (referred to as the “core” sector in aggregate) have seen increased gas consumption over the past few years with an average growth rate of 2 percent, over this same period, which has mainly been driven by population increases. Gas use for power generation has shown robust growth. The market share of power sector gas use, which was 12 percent of total gas use in 1997, increased to 29 percent in 2006. This was due to increased reliance on newly built gas-fired generating capacity, consistent with recent trends throughout North America.

### Historical Gas Imports and Exports

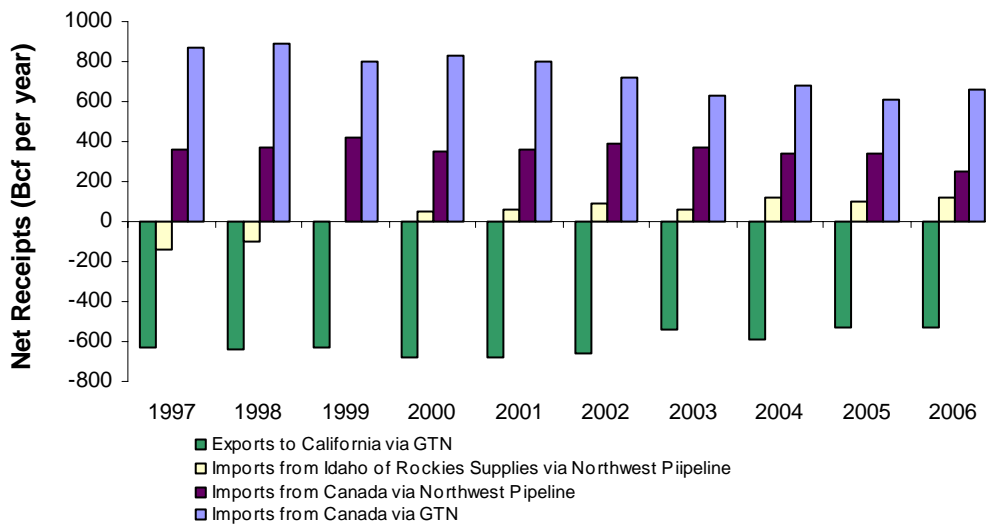
The Pacific Northwest has negligible gas production and must rely on natural gas produced outside the region. Historically Oregon and Washington have been dependent upon gas from the Western Canada Sedimentary Basin (WCSB) and the U.S. Rockies. The Pacific Northwest is also a transit point for gas supplies to California and Nevada. Canadian gas can be imported into the region via either the Northwest or GTN pipelines. Rockies supplies are accessible via Northwest Pipeline.

In 2006 the Pacific Northwest imported over 1,000 Bcf of natural gas or an average of about 2.8 Bcf per day. About 88 percent of these imports came from Canada, while the remaining 12 percent came from the Northern Rockies (Exhibit 2.4). As a percentage of Pacific Northwest imports, Rockies supplies have been growing since 2000. Prior to 2000, Canadian gas was exported via Northwest Pipeline from the Pacific Northwest to serve markets in Idaho and

Nevada . The Pacific Northwest did not receive Rockies gas supplies on a net annual basis before 2000

GTN exports a large portion of the regional imports to the California and Nevada<sup>6</sup> markets. Historically, between 50 and 55 percent of all gas imported into the region was subsequently exported with regional gas consumption accounting for the remaining 45 to 50 percent.

**Exhibit 2.4: Pacific Northwest Historical Gas Imports and Exports (Bcf)**



Source: EIA international and Interstate Movements of Natural Gas by State

<sup>6</sup> Nevada Markets are accessible via the Tuscarora Transmission pipeline.

### 3 Historical Gas Price and Basis Trends

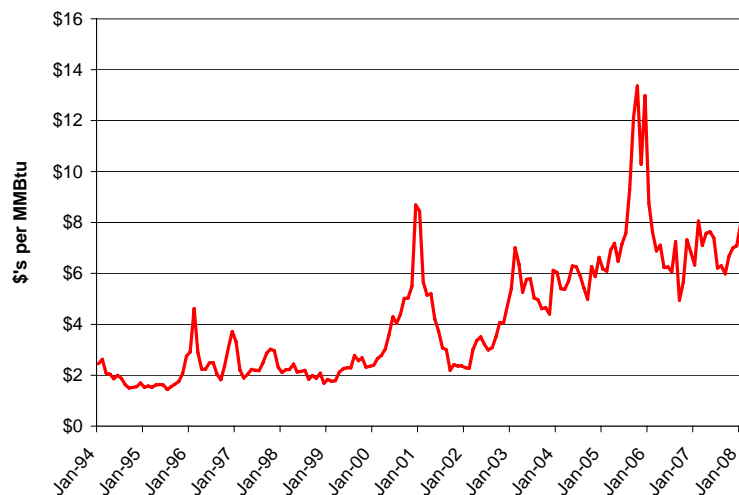
#### Introduction

This section provides an overview of recent North American natural gas price trends and follows with a discussion of gas prices and basis in the Pacific Northwest and surrounding areas.

#### North American Historical Gas Price Trends

The North American natural gas market has undergone a fundamental shift that started at the beginning of this decade. Between the years 2000 and 2007, gas prices at most trading locations throughout North America averaged in excess of \$5 per MMBtu. Since 2005, most have averaged in excess of \$6.50 per MMBtu. Price volatility has increased from 1990s levels, which were fairly constant at between \$2 and \$3 per MMBtu.

**Exhibit 3.1: Recent Historical Trends for Henry Hub Gas Prices**



Source: Platts Gas Daily

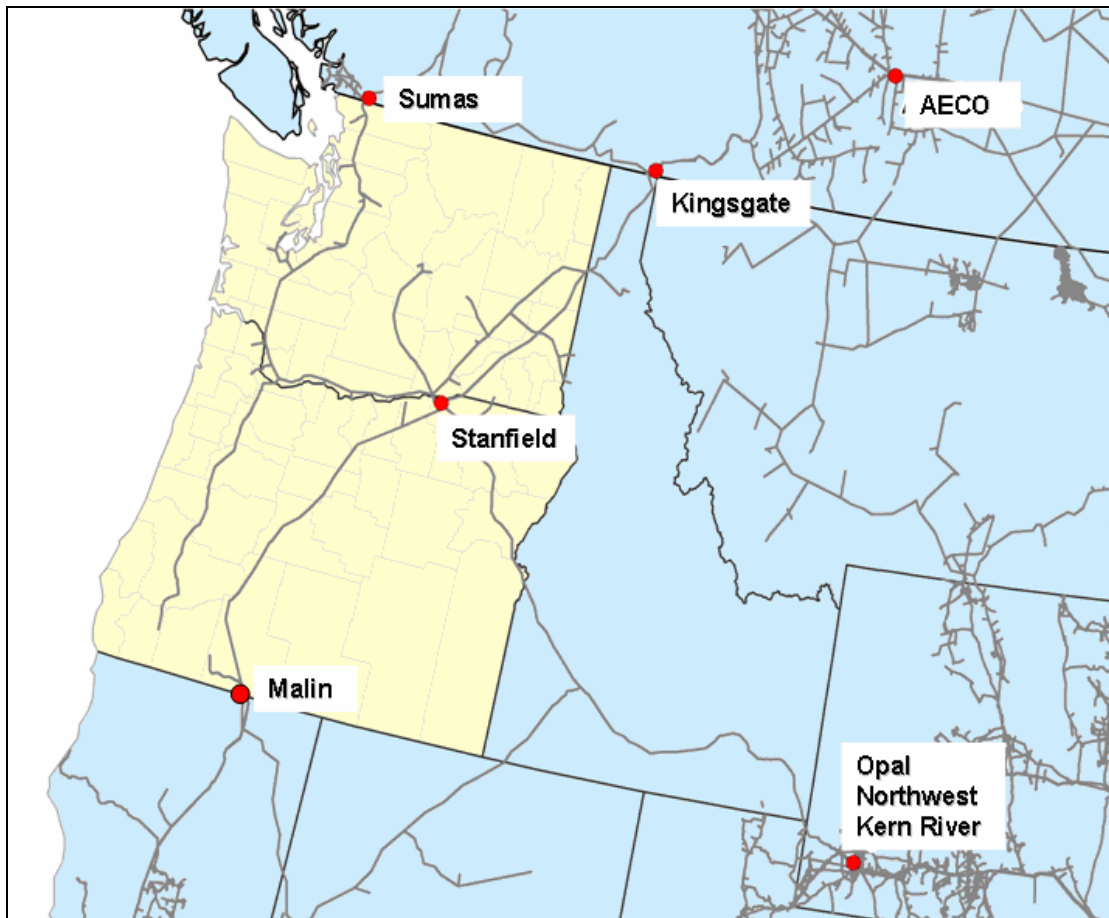
In this new price regime the supply and demand balance for natural gas is much tighter than it was during the 1990s. Throughout most of the 1990s a “gas bubble” existed in the North American natural gas market. Productive capacity for natural gas exceeded gas production, or the amount of gas necessary to satisfy gas consumption at prevailing market prices. Thus, some gas wells were shut-in during times of low market demand. This gas bubble was created during the regulated market environment that existed for natural gas during the 1970s and early 1980s. By and large, it was created during the oil boom that occurred in the U.S. in response to two different oil price shocks that had occurred in the 1970s.

Significant surplus gas well productive capacity was eliminated by overall market growth sometime near 2000. The result has been much higher gas prices and price volatility. The market has a relatively less flexible gas supply ready to satisfy gas demand during cold winter and hot summer weather. The low and stable price levels of the 1990s are not expected to return in the foreseeable future.

## Pacific Northwest Historical Gas Prices and Basis

There is no published index for natural gas price purchases for the Portland, Oregon or Seattle, Washington areas. Pacific Northwest natural gas purchases are usually indexed to nearby area pricing points upstream or downstream, such as Sumas at the Canadian / Washington Border or Malin, Oregon at the California / Oregon border. The most widely referenced pricing points in the area are shown in Exhibit 3.2. Definitions of the index pricing points are discussed in the Appendix.

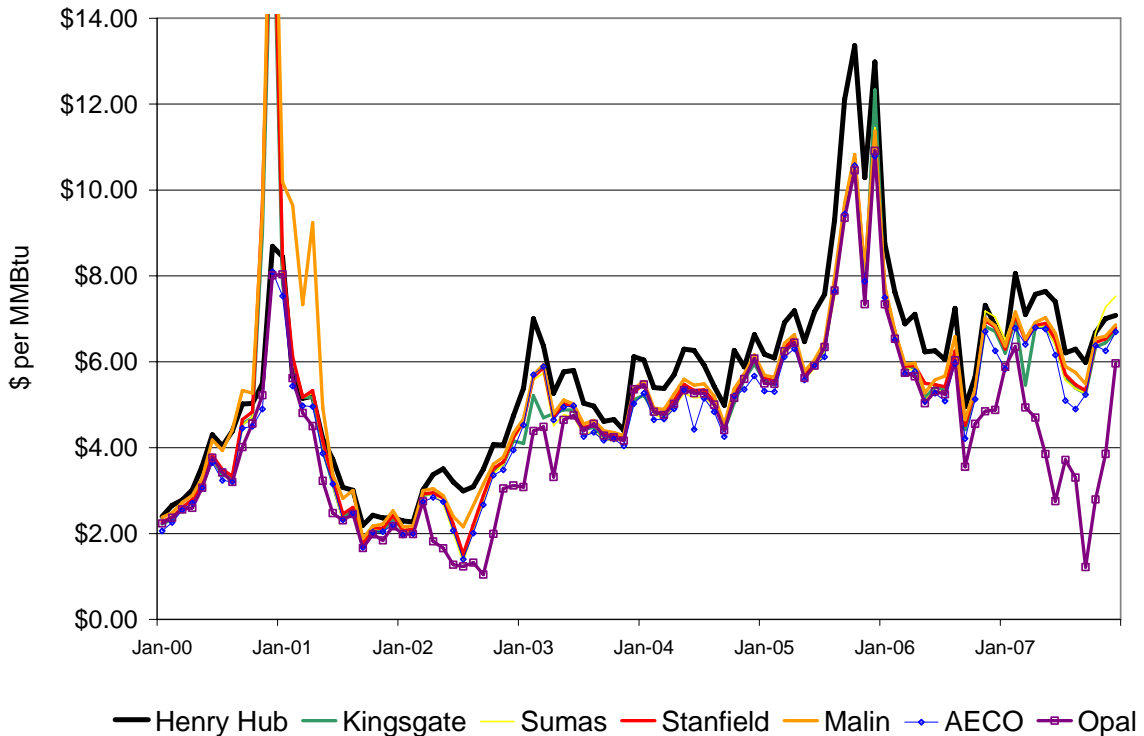
**Exhibit 3.2: Regional Pricing Points**



Source: Platts Gas Daily

Natural gas prices in the Pacific Northwest have followed national trends. The North American supply / demand balance is the major driver of Pacific Northwest Natural gas prices and will continue to be in the future. Specific regional market conditions play a secondary albeit a very important role in determining local gas prices. The North American natural gas pipeline grid covers all of the lower-48 states and the southern portions of Canada. Open access pipeline rules allow natural gas to flow to wherever it is needed. Therefore natural gas prices in the Pacific Northwest rise and fall in tandem throughout the market (Exhibit 3.3).

**Exhibit 3.3: Historical Monthly Natural Gas Prices for Henry Hub and Indexes near the Pacific Northwest (\$'s per MMBtu)**



Average 2000-2007	\$5.67	\$5.09	\$5.14	\$5.21	\$5.48	\$4.84	\$4.42
Average 2005-2007	\$7.50	\$6.53	\$6.63	\$6.63	\$6.72	\$6.37	\$5.59

Source: Platts Gas Daily

Pipeline bottlenecks can, and do, cause certain areas to disconnect from the rest of the larger North American market. This has occurred in the Northern Rockies since production development has historically outpaced new pipeline construction. This has resulted in significantly lower prices, as seen in the Opal index above. However, the price disconnects were temporary. Reconnection with the rest of the market has returned with the construction of new pipeline capacity from Wyoming to the east.

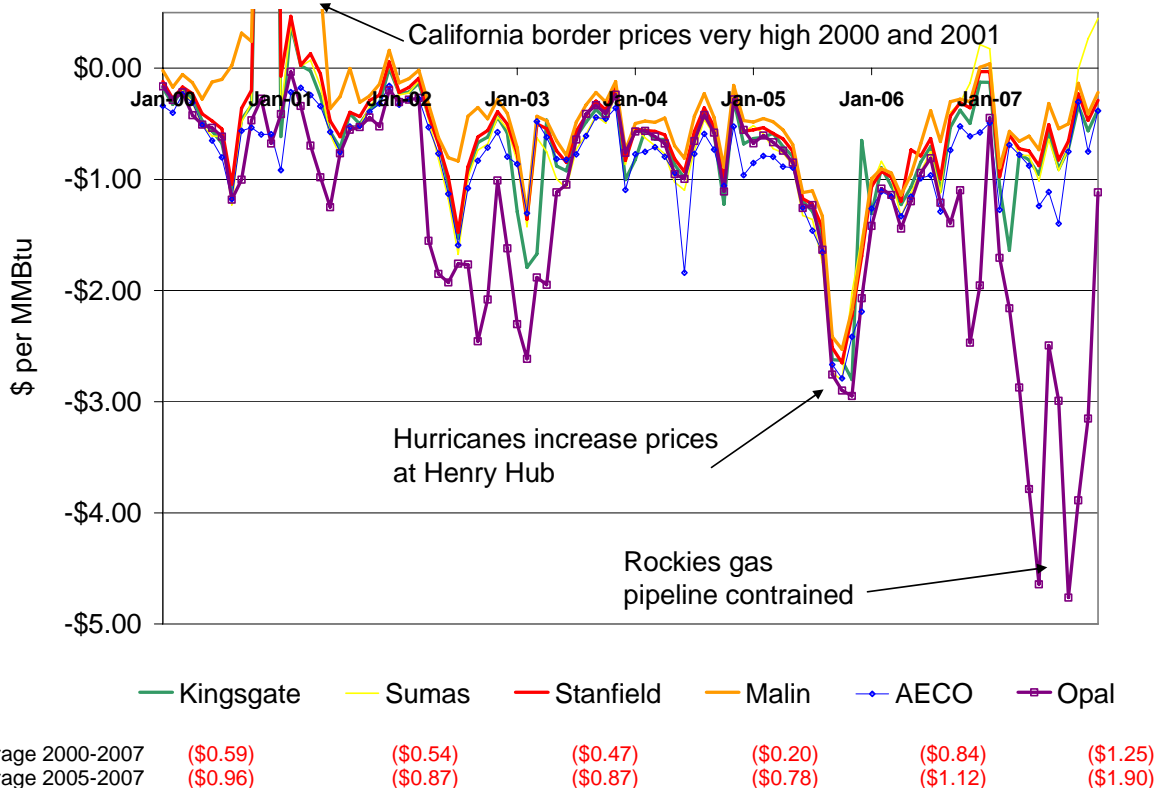
Pacific Northwest gas price indices (Kingsgate, Sumas, Stanfield, and Malin) have averaged within 40 cents per MMBtu of each other since 2000 and within 18 cents since 2005. Canadian imports via Northwest Pipeline at Sumas exhibit a 5 to 10 cent premium over GTN Kingsgate imports. Since 2005, GTN gas deliveries at Malin, Oregon have averaged 18 cents over GTN Canadian receipts. Stanfield prices trend in between the Canadian border and California prices.

Supply basin gas prices almost always trend lower than the price index for the consumption market that they serve. Otherwise, there would not be an economic incentive to incur the transportation costs to move the gas to the market. Since 2005, Western Canada AECO prices have averaged 16 cents and 26 cents per MMBtu lower than Kingsgate and Sumas import prices, respectively. Rockies gas at Opal has averaged just over \$1 per MMBtu less than Stanfield prices since 2005.

Regional price differentials are most often compared to Henry Hub, Louisiana; the location specified in the NYMEX Futures contract. Any geographic price differences are referred to as a "basis". When a basis reference point is not specified, the reference point is assumed to be

Henry Hub. The basis for all of the Pacific Northwest price indexes plus AECO and Opal are shown in Exhibit 3.4. Basis to Henry is not only impacted by market conditions in the Pacific Northwest, but also by market conditions in Louisiana. For example, basis widened to the Pacific Northwest after Hurricanes Katrina and Rita hit the Gulf Coast. This was mainly due to high prices in the Gulf as opposed to low prices out West.

**Exhibit 3.4: Historical Monthly Natural Gas Basis from Henry Hub for Indexes near the Pacific Northwest (\$'s per MMBtu)**



Source: Platts Gas Daily

Pacific Northwest basis from Henry Hub has averaged near minus 50 cents per MMBtu since 2000 and near minus \$1 per MMBtu since 2005. Since 2003, most of the indexes have fluctuated within that minus 50 cent to minus \$1 range, except for during the hurricane periods. Malin has had a slightly smaller basis. Malin basis was strongly positive during the California Energy crisis in 2000.

In the supply regions, Opal basis has averaged in excess of minus \$1 and recently has even approached minus \$5 per MMBtu. The very large Opal basis is expected to disappear as significant pipeline capacity is built out of the Rockies in 2008<sup>7</sup>. However, the Opal basis could easily widened again in the future if incremental pipeline capacity falls behind production development. AECO prices trend higher than Opal prices thus shrinking the basis. AECO basis has averaged between minus 85 cents and \$1.19 per MMBtu.

<sup>7</sup> The first phase of the 1.8 Bcf per day Rockies Express was placed in-service in early 2008.

## 4 Market Projections for the Pacific Northwest Natural Gas Market

### Introduction

This section provides a description of the projections of natural gas consumption for the Pacific Northwest which was used for the regional gas price analysis discussed in this report. It also describes key Base Case scenario assumptions and the different natural gas infrastructure assumptions used in five alternate scenarios.

### Base Projections of Pacific Northwest Gas Consumption

In order to provide a base projection of gas consumption levels for the 2006 to 2030 period, ICF utilized:

- (1) Energy Information Administration data for actual gas consumption for the most recent year available for Oregon and Washington as a base year starting point of consumption by sector;
- (2) Northwest Gas Association (NWGA) forecasted growth rates for gas consumption for 2008 to 2012 for Oregon and Washington; and
- (3) Extrapolations of NWGA forecasted growth rates for 2008 to 2012 for the Pacific Northwest, applied to the 2013 to 2030 period.

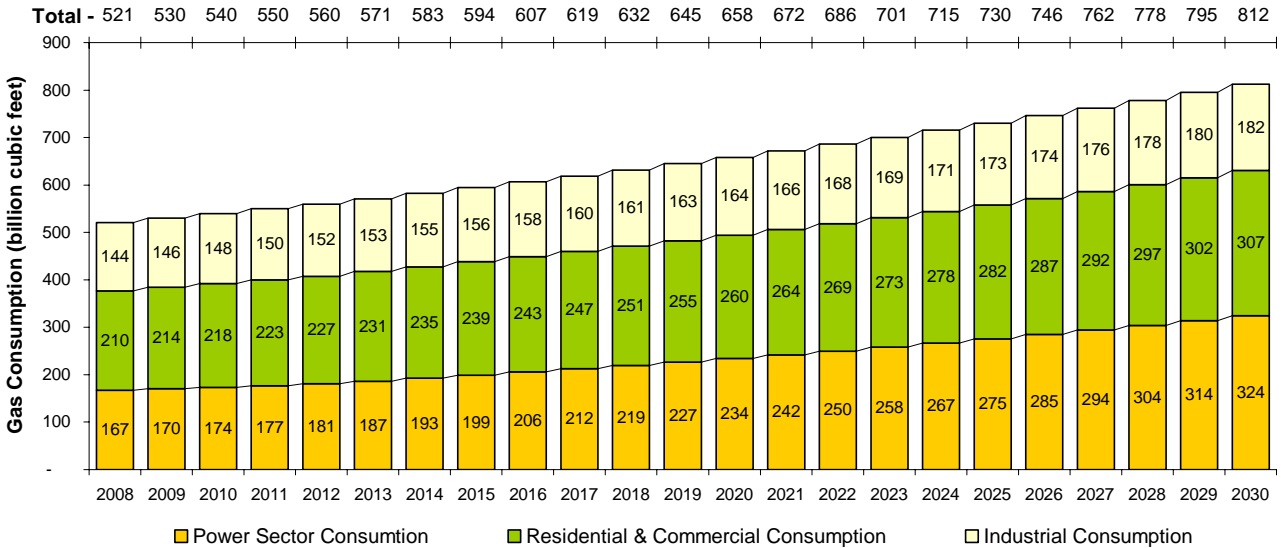
Natural gas consumption growth rates by sector by state are shown in Exhibit 4.1. Projected total Pacific Northwest annual consumption in Bcf per year is shown Exhibit 4.2.

**Exhibit 4.1: Natural Gas Consumption Growth Rate Projections Utilizing Adjusted and Extrapolated NWGA Data**

	Power	CORE	Industrial	All Sectors
<b>OR</b>				
2006-2012 <sup>8</sup>	2.7%	1.7%	0.9%	1.8%
2013-2030	3.3%	1.7%	1.0%	2.2%
2008-2030	3.2%	1.7%	1.0%	2.1%
<b>WA</b>				
2006-2012 <sup>6</sup>	8.3%	2.2%	1.8%	3.9%
2013-2030	3.3%	1.7%	1.0%	2.0%
2008-2030	2.9%	1.8%	1.2%	2.0%
<b>PNW</b>				
2006-2012 <sup>6</sup>	5.2%	2.5%	1.3%	2.9%
2013-2030	3.3%	1.7%	1.0%	2.1%
2008-2030	3.1%	1.7%	1.1%	2.0%

<sup>8</sup> CORE and Industrial sector growth are averaged from 2007-2012.

### Exhibit 4.2: Natural Gas Consumption Projections for All Sectors



Pacific Northwest gas consumption is projected to increase from 521 Bcf in 2008 to 812 Bcf by 2030, an increase of over 50 percent, or a growth rate of about 2 percent per year. Average daily consumption is expected to increase from an average of 1.4 Bcf per day to over 2.2 Bcf per day. All sectors – core heating load, industrial, and power generation – are projected to contribute to regional gas consumption growth. Over half of the increase is due to increased gas-fired generation. The combined space-heating sectors – residential and commercial – account for approximately one-third of the consumption growth. The industrial sector is projected to have a modest incremental growth in gas consumption of 38 Bcf from 2008 to 2030 and accounts for 13 percent of the total increase in market area gas consumption.

### Base Case Projection Key Assumptions – Dynamic Gas Pricing Model

In order to analyze natural gas price and basis impacts of various gas supply infrastructure options for the Pacific Northwest, ICF created a complete North American natural gas market Base Case projection. The North American gas market is an integrated market. Relationships between the Pacific Northwest natural gas market and the greater North American market as a whole must be taken into account to fully evaluate gas supply option impacts.

The Base Case for this report is a modification of the ICF internal March 2008 Gas Market Model (GMM) Base Case, with modifications to match the Pacific Northwest consumption trends discussed above. ICF’s GMM modeling framework projects gas supply, demand, transport and prices on a monthly basis from 2008 through 2030.

Additional key assumptions include:

- (1) U.S. GDP growth rate of 3.0 percent per year
- (2) Oil prices - 3 month average of future prices in the near term.
  - WTI reaches (inflation adjusted \$2006):
    - \$70 per barrel by 2013
    - \$60 per barrel by 2020
    - \$50 per barrel by 2030

- (3) Weather (heating and cooling degree days) is a 30-year average from 1977 to 2006.
- (4) The Alaska pipeline project is built in late 2020 at 4 Bcf per day and expanded by another 2 Bcf per day in 2023.

Assumptions specifically related to the western U.S. include:

- (1) A Costa Azul LNG terminal, operational in June 2008 at a regasification capacity of 1 Bcf per day. Once the terminal is fully operational, load factors at the facility range between 35 and 60 percent.
- (2) Rockies Express East to Clarington, Ohio is operational in June 2009 at a capacity of 1.8 Bcf per day.
- (3) Kern River is expanded by 145 MMcf per day in November 2010 and by an additional 355 MMcf per day in November 2015.
- (4) There is no Ruby Pipeline to Malin (this is added as an alternate scenario).
- (5) There is no Pacific Northwest LNG terminal or an associated pipeline (this is added as an alternate scenario).

### **Alternate Case Projection Assumptions**

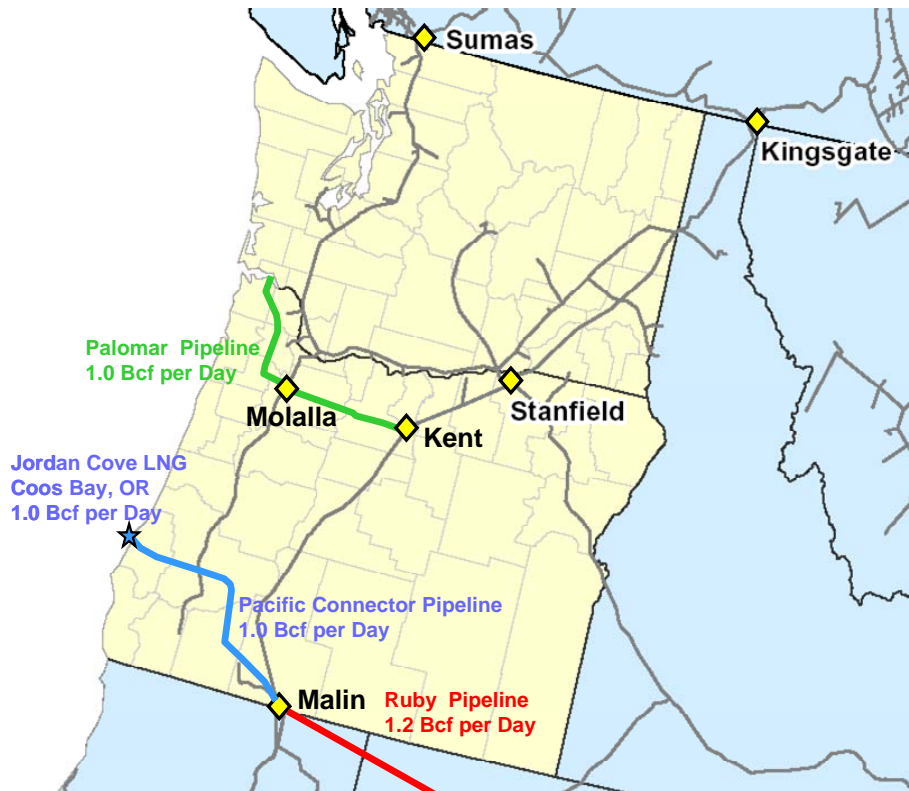
Pacific Northwest gas consumers will encounter varying LNG and pipeline gas supply options. Incremental pipeline capacity or a new Pacific Northwest LNG import terminal may become available in the future. ICF developed five alternate scenarios to help quantify market impacts and potential benefits to Pacific Northwest consumers of various gas infrastructure supply options. The alternate scenarios were run using the Base Case as a starting point. Project infrastructure for the alternate scenarios is shown in Exhibit 4.3.

- (1) **Jordan Cove LNG Import Terminal and the Pacific Connector Gas Pipeline. (*Jordan Cove 100*)** This case adds the Jordan Cove Energy Project LNG import terminal with a regasification capacity of 1 Bcf per day in June 2012. The terminal has a 6 month ramp up period and is fully operational by November 2012. The terminal has a minimum firm supply of 500 MMcf per day with swing supply of up to an additional 500 MMcf per day available dependant upon market prices. The scenario adds the Pacific Connector from Coos Bay, Oregon to Malin, Oregon in-service in June 2012 at a capacity of 1 Bcf per day. Northwest Pipeline capacity allows for 50 MMcf per day to flow north from Roseburg, Oregon to the Portland / Vancouver area and 50 MMcf per day south to markets in southwest Oregon.
- (2) **Jordan Cove LNG Import Terminal and the Pacific Connector Gas Pipeline. (*Jordan Cove 300*)** This case is the same as Case 1, except Northwest Pipeline capacity is expanded from the intersection of the Pacific Connector pipeline near Roseburg, Oregon to north of Eugene, Oregon (about 100 miles). This allows for a full 250 MMcf per day to flow from Roseburg north to the Portland / Vancouver area and 50 MMcf per day south to markets in southwest Oregon.
- (3) **Ruby Pipeline (*Ruby*).** This case adds the Ruby Pipeline from Opal to Malin at a capacity of 1.2 Bcf per day with in-service June 2011. The pipeline also serves load in Northern Nevada including the Reno area.
- (4) **Ruby Pipeline and Palomar Pipeline (*Ruby / Palomar*).** This case adds the Ruby Pipeline under the same size and timing as in scenario 2 above. Additionally, this

scenario adds the Palomar Pipeline from an intersection with Gas Transmission Northwest near Kent, Oregon to Molalla, Oregon, in-service in June 2013 at a capacity of 1 Bcf per day. There is no Pacific Northwest LNG terminal in this scenario.

- (5) **Jordan Cove LNG Import Terminal, the Pacific Connector Gas Pipeline, and Ruby Pipeline (Jordan Cove / Ruby).** This case adds the Jordan Cove LNG terminal, the Pacific Connector Pipeline, and the Ruby Pipeline with the same size and timing as scenarios 2 and 3 above.

**Exhibit 4.3: Alternate Scenario Infrastructure**



### **Impacts of Alternate Cases on Pacific Northwest Gas Consumption**

Exhibit 4.4 shows the impact of each of the alternate scenarios on Pacific Northwest gas consumption. All of the alternate scenarios used the same underlying assumptions for market growth as in the Base Case. The only impact on gas demand in the alternate cases was through changes in prices. All five alternate scenarios reduce Pacific Northwest prices relative to the Base Case, which results in higher levels of gas consumption. The consumption increases were very small – generally less than 1% greater than the Base Case consumption. The changes in consumption were primarily in the industrial and power sectors, as these sectors have much greater price elasticity than the residential and commercial sectors.

### Exhibit 4.4: Impact of Alternate Scenarios on Total Gas Consumption

	<b>Base Case</b>	<b>Jordan Cove 100</b>		<b>Jordan Cove 300</b>		<b>Ruby</b>		<b>Ruby / Palomar</b>		<b>Jordan Cove / Ruby</b>	
	Consumption in Bcf/Year	Change in Bcf/Year	Percent Change	Change in Bcf/Year	Percent Change	Change in Bcf/Year	Percent Change	Change in Bcf/Year	Percent Change	Change in Bcf/Year	Percent Change
2010	540	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
2015	594	1	0.2%	2	0.3%	1	0.2%	2	0.3%	3	0.5%
2020	658	1	0.2%	2	0.3%	1	0.2%	2	0.3%	3	0.4%
2025	730	2	0.3%	2	0.3%	4	0.6%	4	0.6%	6	0.9%
2030	812	5	0.6%	5	0.6%	6	0.8%	7	0.8%	8	1.0%

# 5 Projections for Gas Prices, Basis and Pipeline Flows

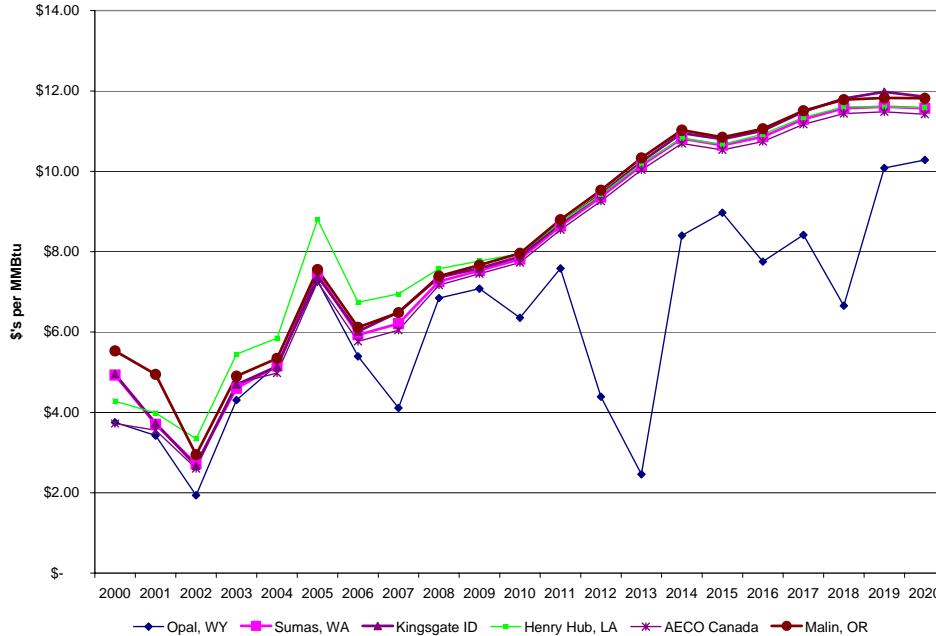
## Introduction

This section provides projected prices and basis for the Pacific Northwest for the Base Case and alternate scenarios, as well as impacts on regional pipeline flows. While all the market projections were run through 2030, this section focuses on 2011 through 2020, which would be the period of greatest impact from the Jordan Cove LNG facility.

## Projected Gas Prices

The Base Case price projections through 2030 for Pacific Northwest indexes plus AECO, Canada, Opal, Wyoming and Henry Hub, Louisiana are shown in Exhibit 5.1. Long-term projections of prices and basis (to 2030) are discussed in the Appendix (Section 0).<sup>9</sup> As previously stated, the Base Case assumes 30-year average weather<sup>10</sup> for all future years and should be thought of as the underlying projected natural gas trend. Due to weather alone, annual natural gas prices will exhibit higher volatility than shown. Generally, colder winters and hotter summers will increase natural gas prices while warmer winters and cooler summers will decrease prices.

**Exhibit 5.1: Base Case Projected Annual Natural Gas Prices for Henry Hub and Indexes near the Pacific Northwest 2000-2030 (\$'s per MMBtu)**



<sup>9</sup> All the projections were run through 2030, but the discussion of price and basis impacts focuses on the time period up to 2020, when the proposed Jordan Cove LNG facility would have the greatest impact.

<sup>10</sup> The projection also assumes normal hydro (snow pack and rainfall) conditions, which is important in determining the amount of hydroelectric generation. Hydro electric generation is a substitute for gas-fired electric generation.

Henry Hub prices, the benchmark for the U.S. national price, are projected to increase from current levels near \$8 per MMBtu to nearly \$12.00 per MMBtu by 2020. Since the North American natural gas market is highly integrated, all of the western indexes, except for Opal, are projected to follow the same general pattern.

Since 2002, Henry Hub prices have exceeded all western North American prices by between 50 cents to over \$1. This relatively large price gap narrows near 2010 due to new west to east pipeline capacity. The narrowing is expected to continue as even more pipeline capacity is built. Through the year 2020, all price indexes are projected to track relatively close, within 50 cents per MMBtu, except for the Opal index.

In the Base Case, the Opal, Wyoming index does not follow national trends. The northern Rocky Mountain area has one of the highest growth rates in natural gas production in North America. This trend is projected to continue into the foreseeable future. New pipeline export capacity has often lagged behind gas production growth causing pipeline bottlenecks and depressed prices in and around Wyoming. If new pipeline capacity out of Wyoming is greater than assumed in the Base Case, then the Wyoming index will track closer to the other price indexes.

Exhibit 5.2 illustrates average annual gas prices at Sumas for the Base Case and the five alternate scenarios. Sumas is a close proxy for natural gas price trends for the Pacific Northwest population centers along the West Coast between Seattle and Portland. With the exception of 2005, when prices spiked due to Hurricanes Rita and Katrina, gas prices at Sumas have been moving up steadily since 2002. The primary reason for the upward trend is that gas prices throughout the U.S. and Canada have been moving upward due to a tightening of supply-demand balance, as was discussed in Section 3. This overall upward trend in gas prices can be seen in the increase in the Henry Hub price, which is also shown in Exhibit 5.2. However, in the Base Case the gas price at Sumas is rising more quickly than the Henry Hub price. The Base Case assumes no additional gas infrastructure in the Pacific Northwest, so as gas demand increases, basis into the region also increases.

All of the alternate scenarios reduce prices at Sumas below the Base Case levels. The lowest price case is Jordan Cove / Ruby, which reduces prices at Sumas by an average of about 50 cents between 2011 and 2020, relative to the Base Case.

**Exhibit 5.2: Projected Sumas Natural Gas Price by Scenario 2000-2020  
(\$'s per MMBtu)**

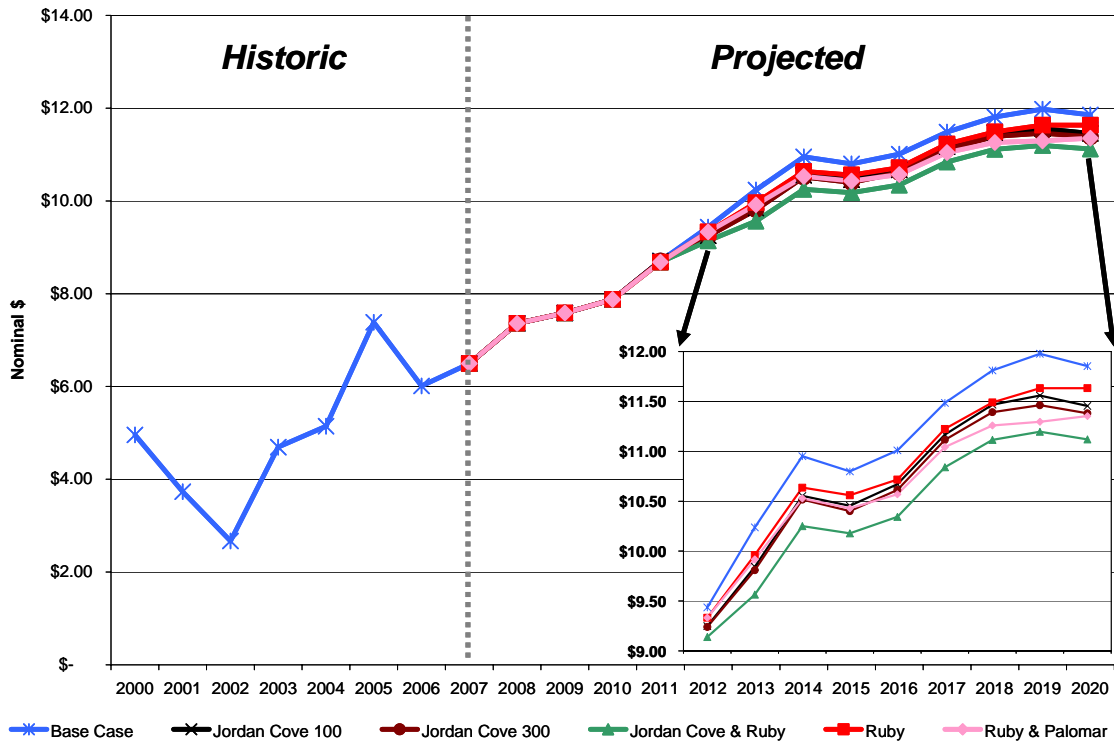
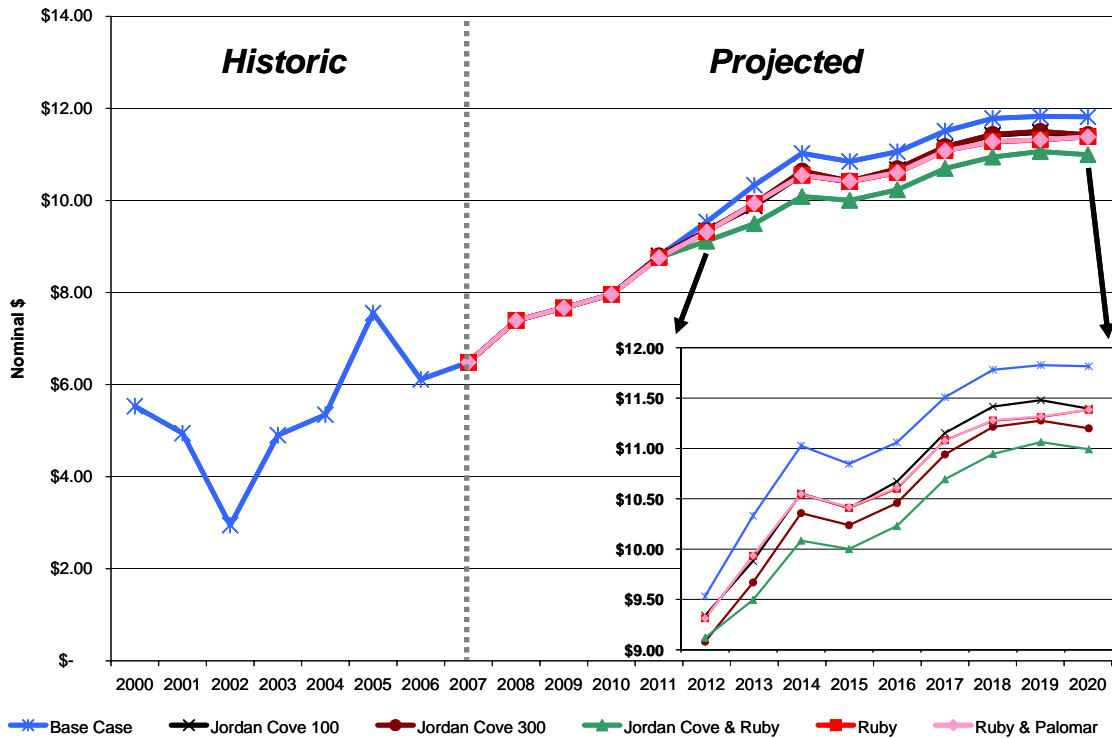


Exhibit 5.3 shows average annual gas prices at Malin for the Base Case and the five alternate scenarios. Both the historical and projected price trends at Malin are very similar to those at Sumas. Prices have been climbing since 2006, and the Base Case projection has the Malin price rising above the Henry Hub price. All of the alternate scenarios reduce prices at Malin below the Base Case, but none of the cases, even the Case with both the Ruby Pipeline and Jordan Cove LNG causes any dramatic price drop. The Jordan Cove / Ruby Case reduces prices at Malin by an average of about 75 cents between 2011 and 2020 relative to the Base Case.

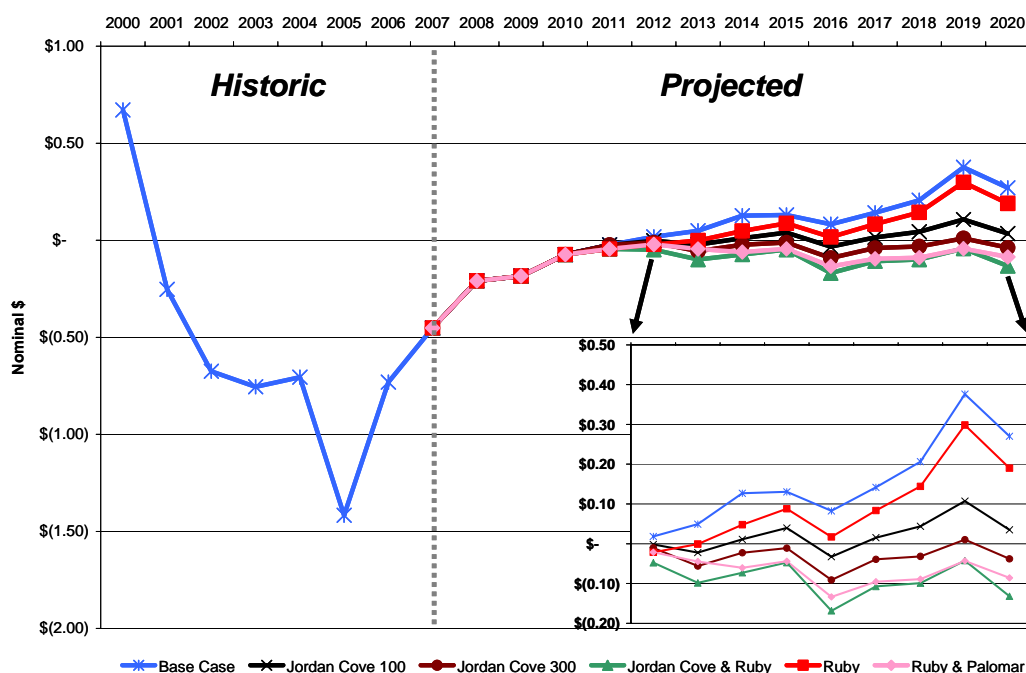
**Exhibit 5.3: Projected Malin Natural Gas Price by Scenario 2000-2020  
(\$'s per MMBtu)**



**Projected Basis**

The basis from Henry Hub to Sumas has been strongly negative since 2001, meaning that gas has been relatively less expensive at the Washington / Canada border than it has been in Louisiana. Exhibit 5.4 illustrates the Henry Hub to Sumas average annual basis for the Base Case and the 4 five alternate scenarios. Ignoring 2005 – the year of the Hurricanes Katrina and Rita – basis had stabilized near 75 cents per MMBtu. However, the basis has been rising since 2006. The main reason is a reduction of the available Canadian natural gas supplies due to lower production and higher gas consumption rates in Western Canada. Western Canada’s higher gas consumption is due in part to gas used in oil sands development.

**Exhibit 5.4: Projected Sumas to Henry Hub Average Annual Basis by Scenario 2000-2020 (\$'s per MMBtu)**



In the Base Case, which assumes no additional natural gas infrastructure to the Pacific Northwest, the increasing basis trend continues through to 2020. The Sumas basis turns positive<sup>11</sup> by 2012 and reaches 35 to 40 cents per MMBtu by 2020. All five other alternate scenarios reduce the Henry Hub to Sumas basis relative to the Base Case. This is expected since the gas infrastructure assumed in each case can bring additional gas supplies to the region.

The Ruby Case has the least impact on Sumas basis as compared to the other four alternate scenarios. The Ruby pipeline can bring natural gas supplies to the Oregon / California border at Malin. However, without incremental pipeline capacity into the western portions of Oregon and Washington, there are limitations on how much additional gas supply can reach Portland and Seattle. Therefore, the Sumas basis in the Ruby Case is only slightly below the Base Case trend. However, if additional east-to-west pipeline capacity is added as in the Ruby / Palomar Case, there is a noticeable impact on the Sumas basis. By 2020, the Sumas basis in the Ruby / Palomar case is still slightly negative and is about 40 cents per MMBtu below the Base Case level.

The two Jordan Cove Cases bring additional gas supplies directly to the western portion of the Pacific Northwest. Although the Jordan Cove LNG import facility has a maximum output of 1 Bcf per day, current pipeline capacity limits volume to about 100 MMcf per day into Oregon consumption markets. The Jordan Cove 300 case assumes Northwest Pipeline is enhanced to allow 300 MMcf per day to Oregon and Washington markets. However, as seen in the Ruby only Case, incremental gas supplies at Malin, Oregon still impact Sumas basis by freeing up

<sup>11</sup> Meaning Sumas, Washington natural gas prices are higher than Henry Hub, Louisiana prices.

Canadian gas supplies. Therefore gas flowing on the Pacific Connector pipeline also tends to reduce Sumas price basis. The Sumas basis in the two Jordan Cove Cases hover around parity with Henry Hub Prices from 2010 to 2020. The Jordan Cove 300 basis can be up to 10 cents per MMBtu lower than the Jordan Cove 100 Case.

The case with the largest impact on Sumas basis relative to the Base Case is the Jordan Cove / Ruby Case. In this scenario incremental LNG supplies and Rocky mountain production can enter the Pacific Northwest. The combination of both supplies has a greater impact on basis than either supply alone. In the Jordan Cove / Ruby Case, the Sumas basis averages 22 cents per MMBtu lower than the Base Case between 2011 and 2020.

The basis trend for Malin is similar (Exhibit 5.5). While basis from Henry Hub to Malin have been negative (Malin prices lower than Henry Hub), the basis have been rising since 2006. In the Base Case, the increasing trend continues through 2014, then basis stabilizes at about 20 cents per MMBtu above Henry Hub. In all of the alternate scenarios, basis is reduced relative to the Base Case. The greatest reduction is in the Jordan Cove / Ruby case, where basis averages about 25 cents per MMBtu below the Henry Hub price, or about 45 cents per MMBtu lower than the Base Case.

**Exhibit 5.5: Projected Malin to Henry Hub Average Annual Basis by Scenario 2000-2020 (\$'s per MMBtu)**

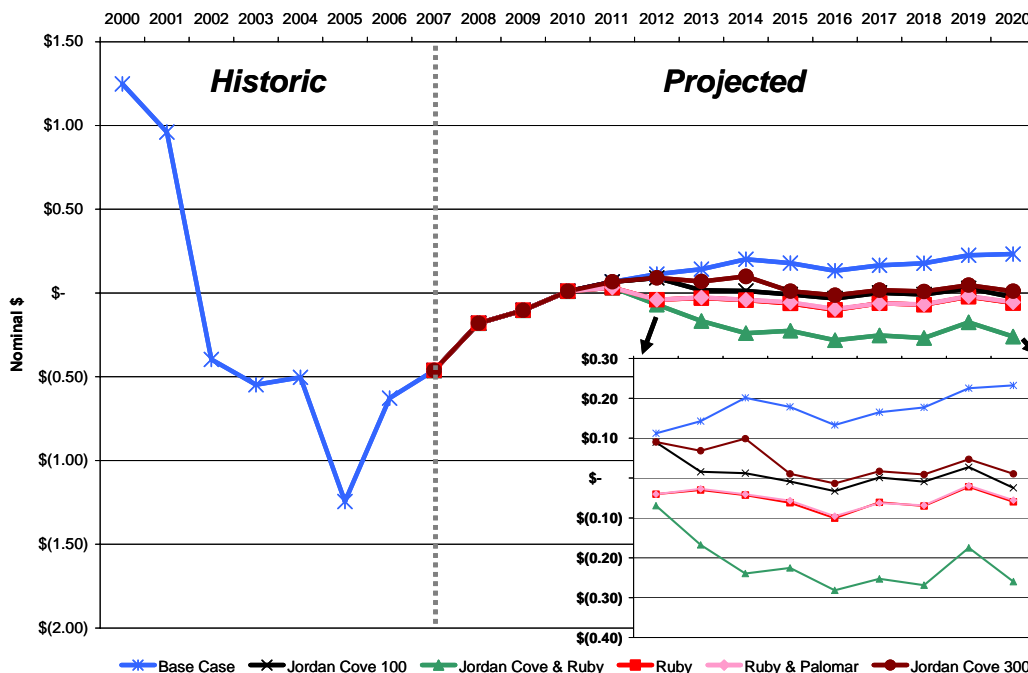


Exhibit 5.6 shows the Sumas to Henry Hub basis for the Base Case and the five alternate scenarios for the month of January, which is the region's peak gas demand month. As with the average annual basis, January basis was negative (meaning Sumas prices are lower than at Henry Hub) through 2006. Ignoring the 2005 values (because of the impact of that year's hurricanes on prices), January basis differentials averaged about 50 cents per MMBtu. Like the average annual basis, the January basis at Sumas has been rising since 2006. However, since January's pipeline utilization is much higher than the average annual value, the increase in

January basis is also higher. In the Base Case, January Basis at Sumas stabilizes at around 50 cents per MMBtu between 2012 and 2016, but then climbs to \$2.69 per MMBtu by 2020, as pipeline utilization rises well above historic levels.

As with the average annual basis, the Ruby Case has the least impact on Sumas basis, compared to the other four alternate scenarios. Because the Ruby pipeline only brings Rockies gas as far as Malin, the Sumas basis in the Ruby Case is only slightly below the Base Case trend. When additional east-to-west pipeline capacity is added as in the Ruby/Palomar Case, there is a large impact on the Sumas basis. By 2020, the Sumas January basis in the Ruby / Palomar case is about \$2.30 cents per MMBtu below the Base Case level.

As indicated in Exhibit 5.6, the Jordan Cove 100, the Jordan Cove 300 and the Jordan Cove / Ruby cases have January basis trends that are similar. As with the Ruby Case, the addition of Ruby pipeline in the Jordan Cove / Ruby Case has very little additional impact on the Sumas basis. In all three of these cases, January basis averages about 40 cents per MMBtu from 2011 to 2020. By 2020, the January basis is more than \$2 per MMBtu below the Base Case for those cases that include the Jordan Cove facility.

**Exhibit 5.6: Projected Sumas to Henry Hub January Basis by Scenario 2000-2020 (\$'s per MMBtu)**

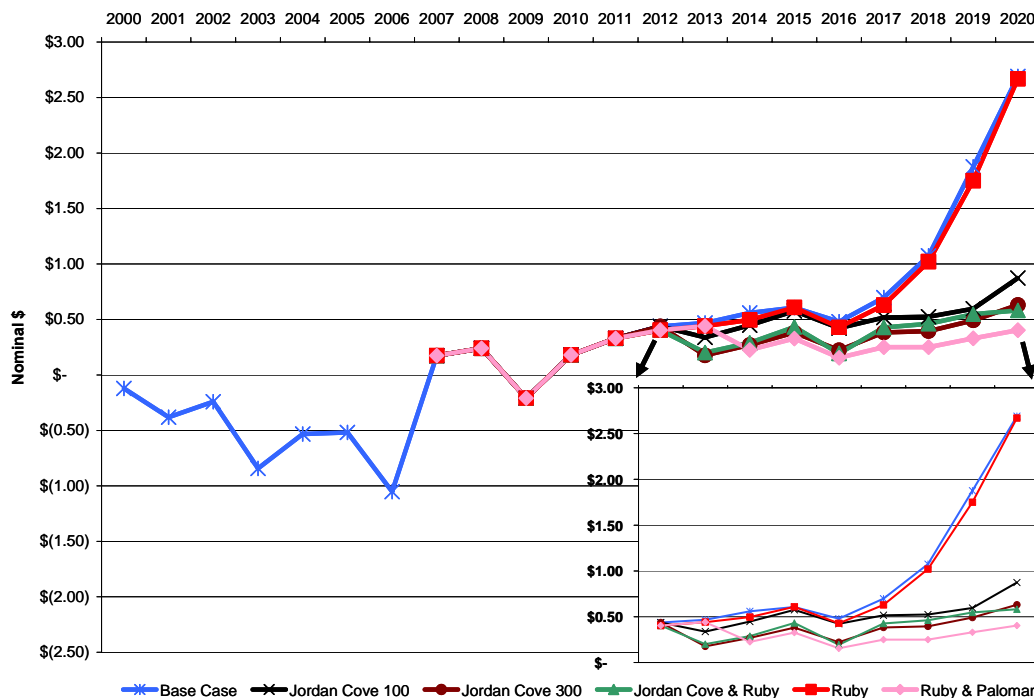
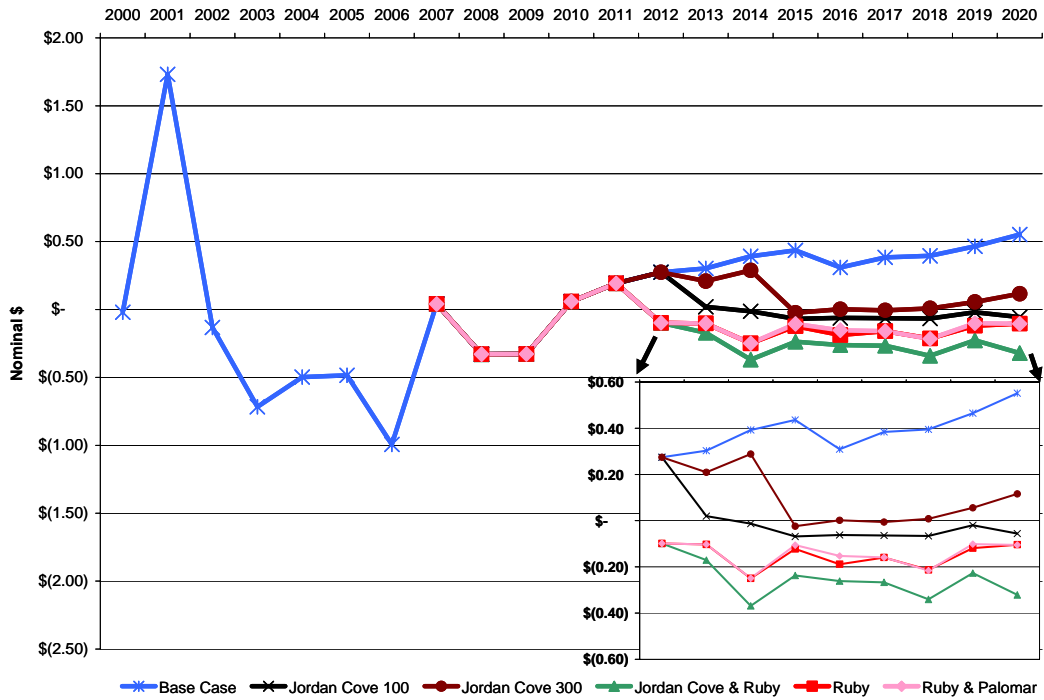


Exhibit 5.7 shows the Malin to Henry Hub basis for the Base Case and the five alternate scenarios for the month of January. January basis was negative from 2002 through 2006, averaging about 60 cents below the Henry Hub price. Like the average annual basis, the January basis at Malin has increased since 2006. However, since January's pipeline utilization is much higher than the average annual value, the increase in January basis is also higher. In the Base Case, January Basis at Malin through 2015, then remains between 40 and 50 cents

per MMBtu above Henry Hub prices. All of the alternate scenarios reduce January basis to Malin relative to the Base Case. The greatest reduction is in the Jordan Cove / Ruby case, where January basis averages about 60 cents per MMBtu below the Base Case.

**Exhibit 5.7: Projected Malin to Henry Hub January Basis by Scenario 2000-2020 (\$'s per MMBtu)**



## Projected Natural Gas Pipeline Flows

Exhibit 5.8 shows the projected flows along major pipeline corridors in the Northwest for the Base Case through 2020. In the Base Case, imports from Canada increase by a total of 328 MMcfd between 2011 and 2020, with 148 MMcfd additional at Sumas and 180 MMcfd additional at Kingsgate. While imports at Kingsgate increase, the flows south from Stanfield to Malin are down slightly, indicating that more of the Canadian imports are staying in the Oregon and Washington to meet growing demand in these states. Flows across Washington state increase, as most of the demand increase is along the coast. Flows from the Rockies on Northwest Pipeline are down slightly, as new pipeline capacity east-bound out of the Rockies draws more gas to eastern markets.

**Exhibit 5.8: Projected Pipelines Flows for the Base Case (Average MMcfd)**

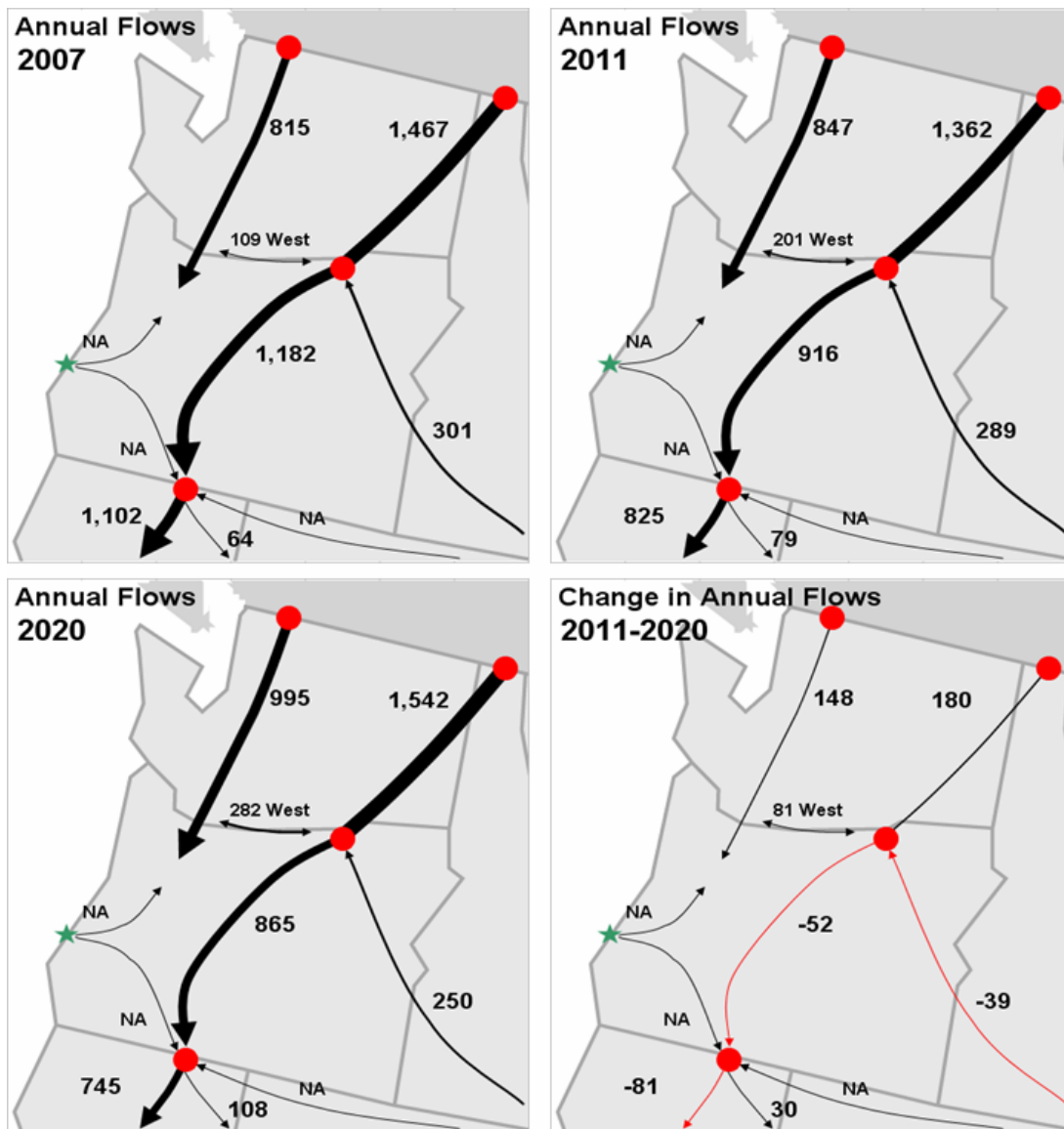
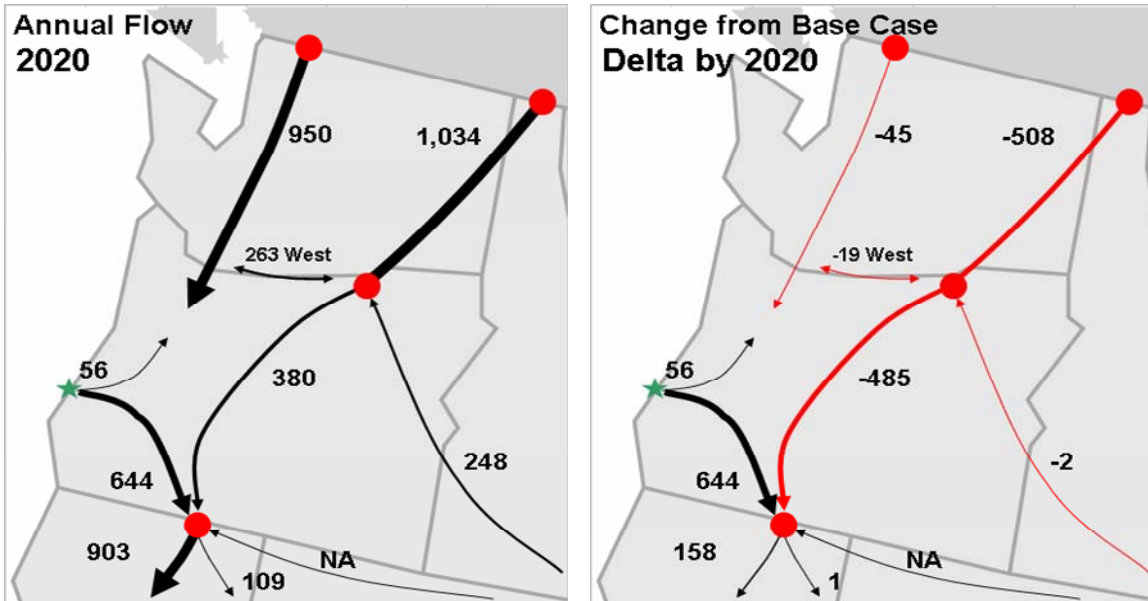
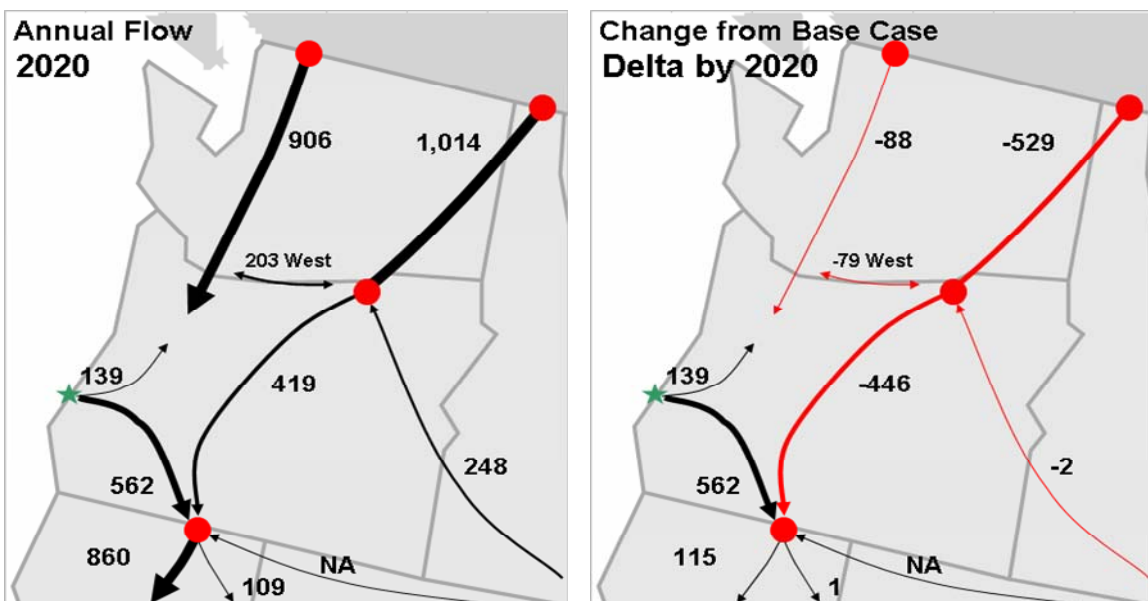


Exhibit 5.9 and 5.10 shows the 2020 flows and the changes in 2020 flows relative to the Base Case for the Jordan Cove 100 case and the Jordan Cove 300 case respectively. In 2020, both Jordan Cove cases have an additional supply of approximately 700 MMcfd of LNG imports. Of this 700 MMcfd, an average of 56 MMcfd flows into the western Oregon / Washington market in the Jordan Cove 100 case, while the rest flows to Malin on the Pacific Connector pipeline. With the greater pipeline capacity in the Jordan Cove 300 case, flow directly to local markets averages 139 MMcfd per day.

**Exhibit 5.9: Changes in Pipelines Flows for the Jordan Cove 100 Case versus the Base Case (Average MMcfd)**



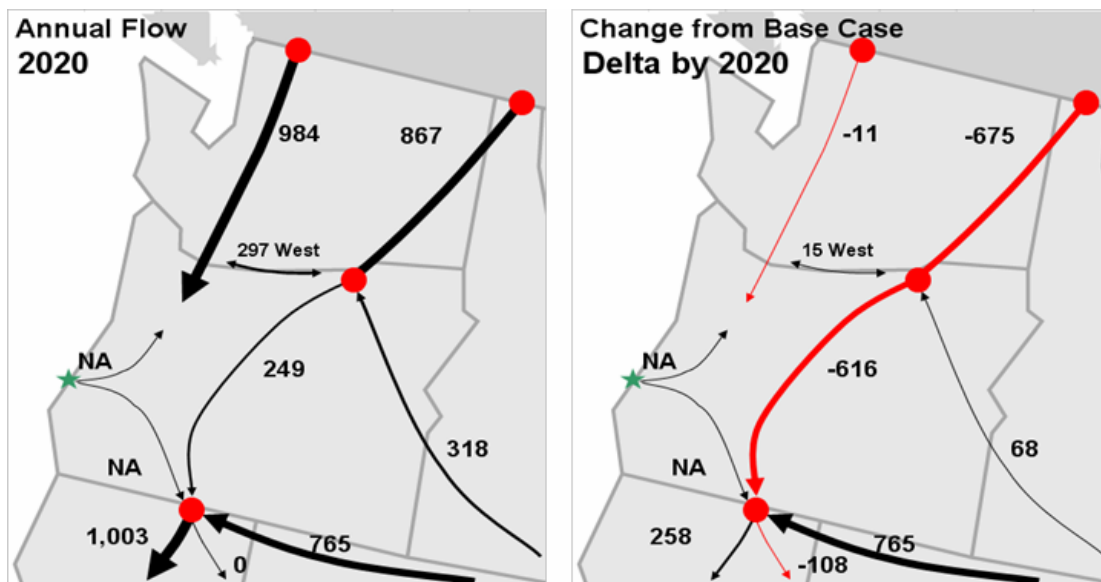
**Exhibit 5.10: Changes in Pipelines Flows for the Jordan Cove 300 Case versus the Base Case (Average MMcfd)**



Flows across Washington are reduced, as incremental demand growth in western Oregon and Washington is being met by LNG from Jordan Cove. There is still a net average flow to the west in both Jordan Cove cases even though it is reduced. Imports from Canada are reduced by between 550 to 600 MMcfd with the bulk of the reductions on GTN. Flow from the Rockies is essentially unchanged.

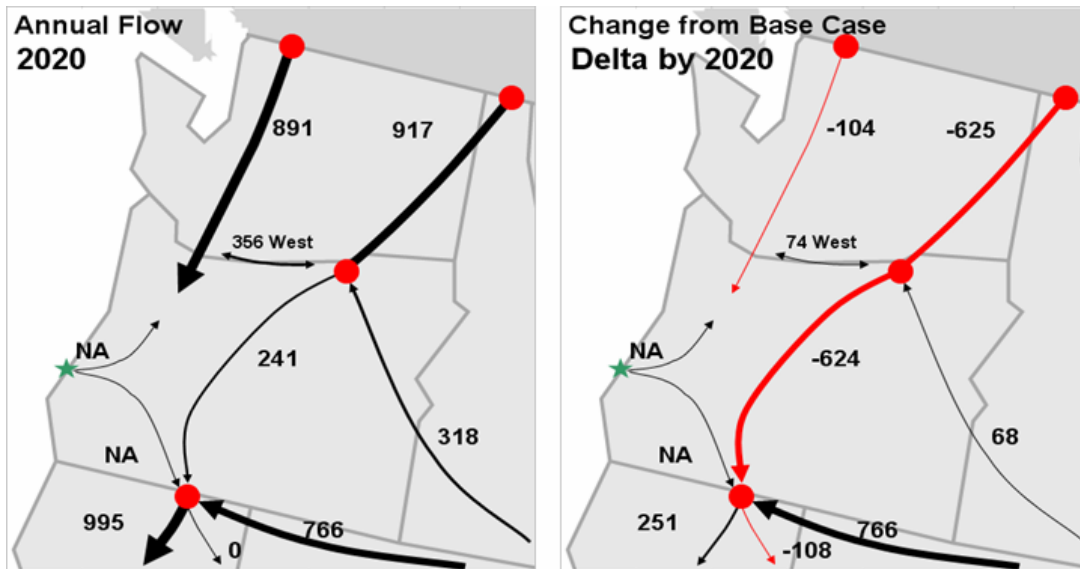
In the Ruby Case, the Ruby Pipeline provides an additional flow of about 770 MMcfd of Rockies gas into Malin, as shown in Exhibit 5.11. The primary impact of the Ruby Pipeline is to displace imports from Canada at Kingsgate and reduce the flow of gas along the GTN system. Imports at Sumas are down only slightly, and the flows across Washington on Northwest Pipeline are higher than the Base Case. Imports at Sumas on Northwest Pipeline are down only slightly.

**Exhibit 5.11: Changes in Pipelines Flows for the Ruby Pipeline Case versus the Base Case (Average MMcfd)**



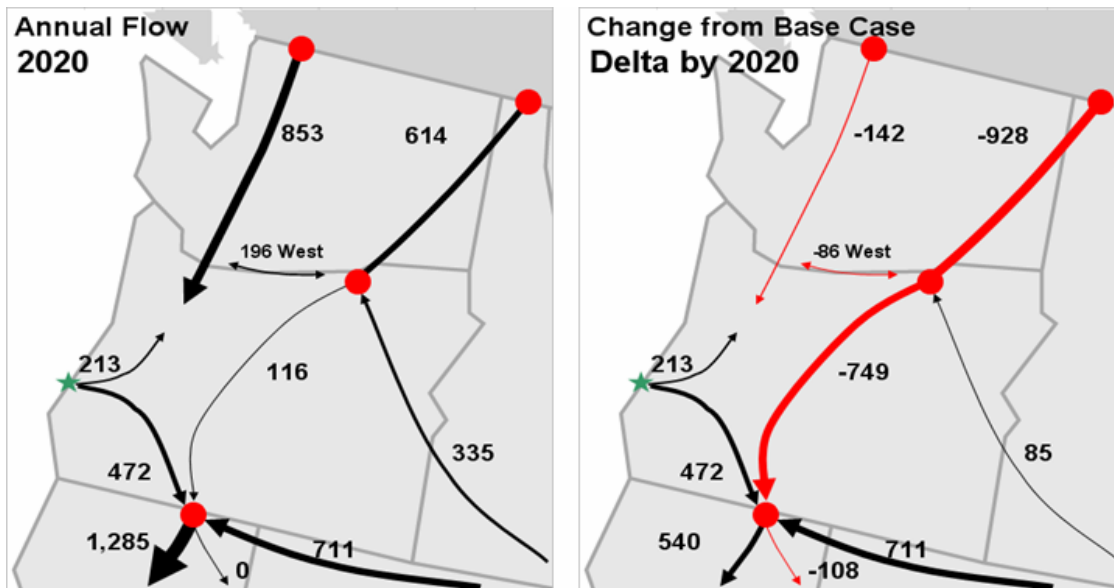
In the Ruby / Palomar scenario (Exhibit 5.12), there is a greater impact on the flows on the Northwest Pipeline system compared to the case with Ruby Pipeline alone. In the Ruby / Palomar scenario, flows from east to west across Washington and Oregon are greater due to the additional capacity east-to-west capacity provided by the Palomar pipeline. Flows east-to-west are 74 MMcfd greater than the Base Case by 2020, and about 60 MMcfd greater than the case with Ruby Pipeline alone. As a result of the increase in east-to-west flows, imports at Sumas on Northwest Pipeline are reduced by about 100 MMcfd, compared to the Base Case, and imports are about 90 MMcfd lower than the case with Ruby Pipeline alone.

**Exhibit 5.12: Changes in Pipelines Flows for the Ruby / Palomar Case versus the Base Case (Average MMcfd)**



The Jordan Cove / Ruby scenario has the (Exhibit 5.13) has the greatest impact on Canadian imports. In total, this case reduced imports from Canada by almost 1,100 MMcfd by 2020, with over 900 MMcfd of the reduction occurring on GTN's imports at Kingsgate. LNG imports at Jordan Cove are about 700 MMcfd, and about 30 percent of the imports stay in the western Oregon / Washington market area. As a result on the LNG imports, flows east-to-west on Northwest Pipeline are nearly 90 MMcfd lower than the Base Case.

**Exhibit 5.13: Changes in Pipelines Flows for the Jordan Cove / Ruby Case versus the Base Case (Average MMcfd)**



# Appendix

## Existing Natural Gas Market Infrastructure

The Pacific Northwest has essentially no natural gas production.<sup>12</sup> The Pacific Northwest must import all of its natural gas. Historically the region has relied exclusively on supplies delivered from other areas via interstate pipelines. Two interstate pipelines transport gas into and through Washington and Oregon - Northwest Pipeline and Gas Transmission Northwest (GTN) (Exhibit 2.1). Most of the Pacific Northwest is served by Northwest Pipeline. GTN is mainly a conduit for gas supplies to California and Nevada, however GTN does serve some markets along its route as well as deliver gas to Northwest Pipeline for regional consumption. Approximately 4.1 Bcfd of pipeline transportation capacity enters the region (from Canada and Idaho) and 2.2 Bcfd of transportation capacity exits into California. The characteristics for each pipeline are summarized below.

The Northwest Pipeline Corporation is owned by The Williams Companies, Inc. Northwest Pipeline extends from the San Juan Basin in New Mexico to the Washington / Canadian border through the states of New Mexico, Colorado, Utah, Wyoming, Idaho, Oregon, and Washington. The total system consists of 4,120 miles of pipe, 42 compressor stations and 12.4 Bcf of working gas storage. It has a peak delivery of 3.4 Bcf per day and an average daily throughput of approximately 1.8 billion cubic feet.

Northwest Pipeline can receive approximately 1.3 Bcf per day from Westcoast Energy at Sumas Washington along the Canadian Border. Natural gas also enters the region through Northwest's line entering Oregon near Caldwell, Idaho with a capacity of approximately 480 MMcf per day. Northwest can also receive gas from Gas Transmission Northwest at Stanfield, Oregon at approximately 640 MMcf per day and Spokane, Washington at 300 MMcf per day. The capacity of Northwest's Columbia line between Stanfield, Oregon and Vancouver, Washington which enters Southwest Washington from the East is approximately 550 MMcf per day.

Gas Transmission Northwest (GTN) is owned by TransCanada. Its pipeline is 612 miles and extends from Kingsgate, Idaho to Malin, Oregon at the Oregon / California border. As mentioned above, this pipeline was built mainly to bring Canadian gas supplies to California. However, it offers an alternative method of bringing gas supplies into Washington and Oregon through its interconnect with Northwest pipeline at Stanfield, Oregon and Spokane, Washington.

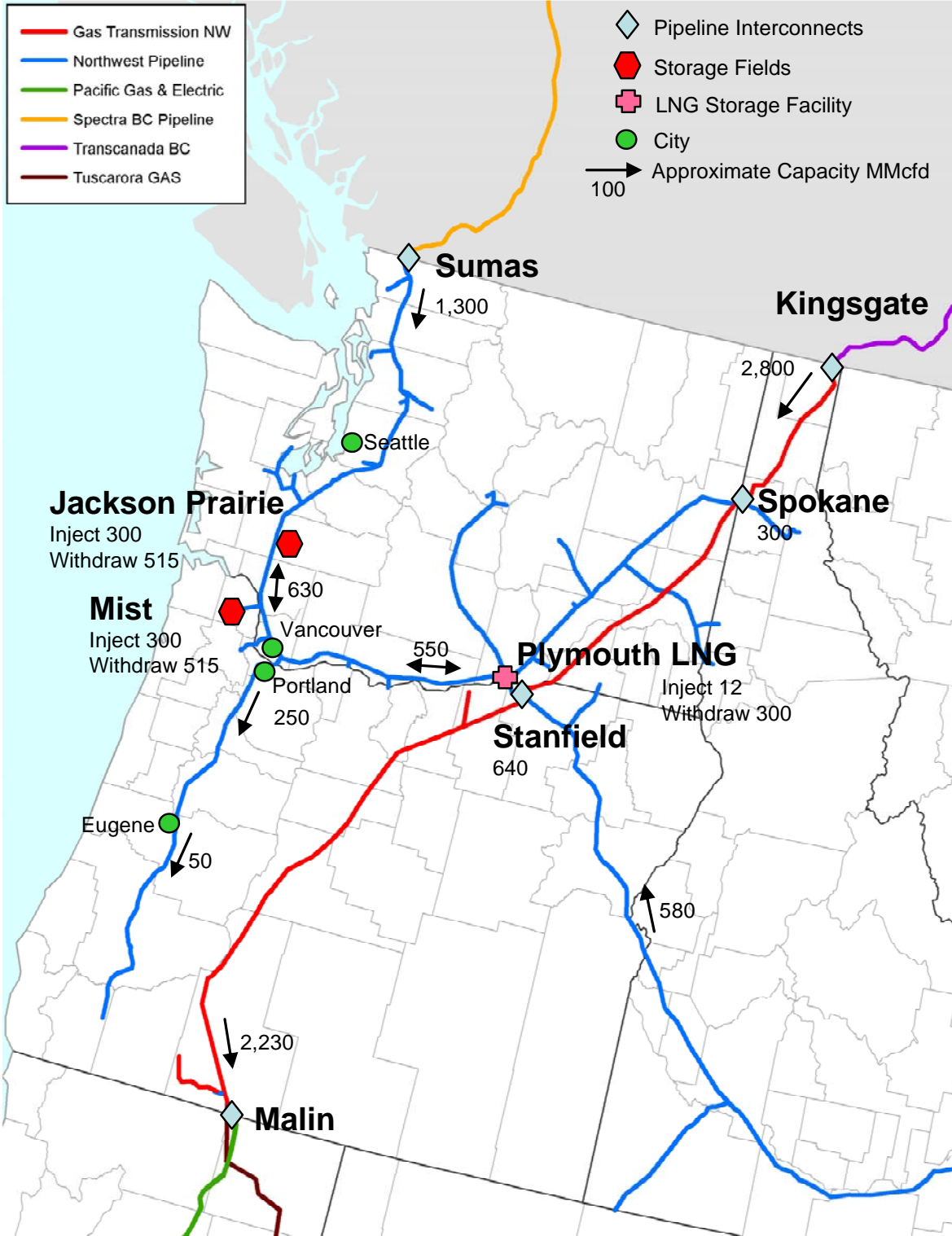
GTN can receive approximately 2.8 Bcf per day from the Foothills pipeline at Kingsgate Idaho. GTN delivers gas to two pipelines at the California border - Tuscarora Transmission and Pacific Gas and Electric Company (PGE)<sup>13</sup>. The capacity to Tuscarora is 185 MMcf per day. The capacity to PGE is over 2.2 Bcf per day. The majority of GTN's pipeline capacity is dedicated to markets on PGE.

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<sup>12</sup> In 2006, Washington had no marketed production and Oregon had 621 MMcf or about 0.1 percent of the Pacific Northwest consumption for the year.

<sup>13</sup> PGE is an intrastate pipeline and distribution company operating completely within California.

Exhibit 5.14: Major Pipelines in the Pacific Northwest



Source: Pipeline Company Electronic Bulletin Boards (EBBs) and other Public Sources.

## Existing Natural Gas Storage

There are two conventional natural gas storage fields in the region - the Mist field and the Jackson Prairie field. Both serve the population centers near the coast and are located in Columbia County, Oregon and Lewis County, Washington respectively. There is also a liquefied natural gas (LNG) storage facility near Plymouth Washington (see Exhibit 2.1 above).

The Mist Storage field is located just to the Northwest of the Portland / Vancouver area. It is operated by the area distribution company, Northwest Natural. It has a maximum capacity of nearly 16 Bcf and a maximum delivery of 515 MMcf per day. It is used predominately to serve Northwest Natural's sales to core heating load customers. However with expansions of the facility in recent years, Northwest Natural has contracted capacity to store third party gas. In 2005, Portland General Electric signed a 10-year contract to augment gas pipeline service to its Beaver Generating Plant in the area. Northwest Natural also offers both firm and interruptible storage services for transportation customers in its distribution system.

The Jackson Prairie field is owned in three equal shares by Northwest Pipeline, Puget Sound Energy, and Avista Utilities. It is an aquifer based facility and is used mainly to meet seasonal variations between winter and summer demand. The working gas capacity of the field is approximately 22 Bcf. The field has a current max delivery of 1 Bcf per day. It is in the process of being expanded. The working gas capacity is being expanded in annual stages. By 2010 the total working gas capacity will be approximately 25.4 Bcf.

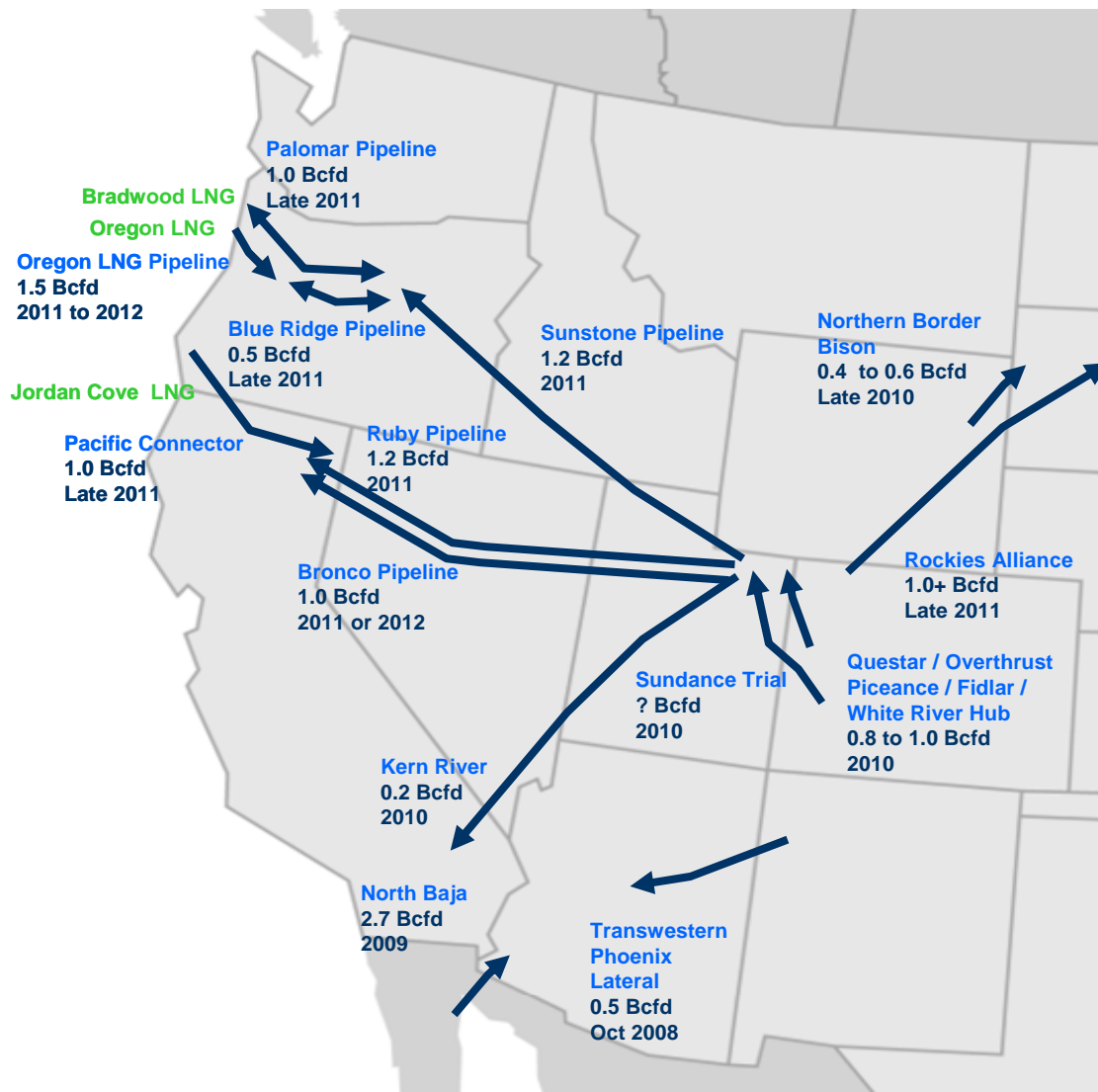
Northwest Pipeline owns and operates a liquefied natural gas storage facility located in Plymouth, Washington about 12 miles to the west of the interconnect with GTN in Stanfield, Oregon. This facility provides standby service for Northwest Pipeline's customers during extreme peaks in demand. The facility has a total LNG storage capacity equivalent to 2.4 Bcf of gas, liquefaction capability of 12 MMcf per day and regasification capability of 300 MMcf per day. At these maximum fill and withdrawal rates, it takes a minimum of 200 days to completely fill the facility and only 8 days to empty it. The gas at the LNG plant is mainly owned by storage gas is owned by major Northwest Pipeline's transportation customers.

## Proposed Infrastructure: Pipelines and LNG Import Terminals

### Proposed Natural Gas Pipelines in the Western U.S.

There are fourteen different pipeline projects that have been recently proposed for the Western U.S. as shown in Exhibit 5.15. Of the thirteen, seven would have a direct impact on the Pacific Northwest: Bronco, Ruby, Sunstone, Palomar, Oregon LNG Pipeline, and Pacific Connection. Both the Bronco and Ruby pipelines would carry gas from the Rockies to Malin, Oregon. The Sunstone Pipeline would also carry gas from the Rockies, but it would deliver to GTN and Northwest Pipeline at Stanfield. Palomar would carry gas westward from Stanfield toward the coast. Palomar would also have the option of transporting from west-to-east (to Stanfield), if the Bradwood LNG facilities is constructed. Two of the proposed pipelines, Oregon LNG and Pacific Connection, are associated with LNG import facilities and are discussed in more detail below.

**Exhibit 5.15: Proposed Western Pipeline Projects**



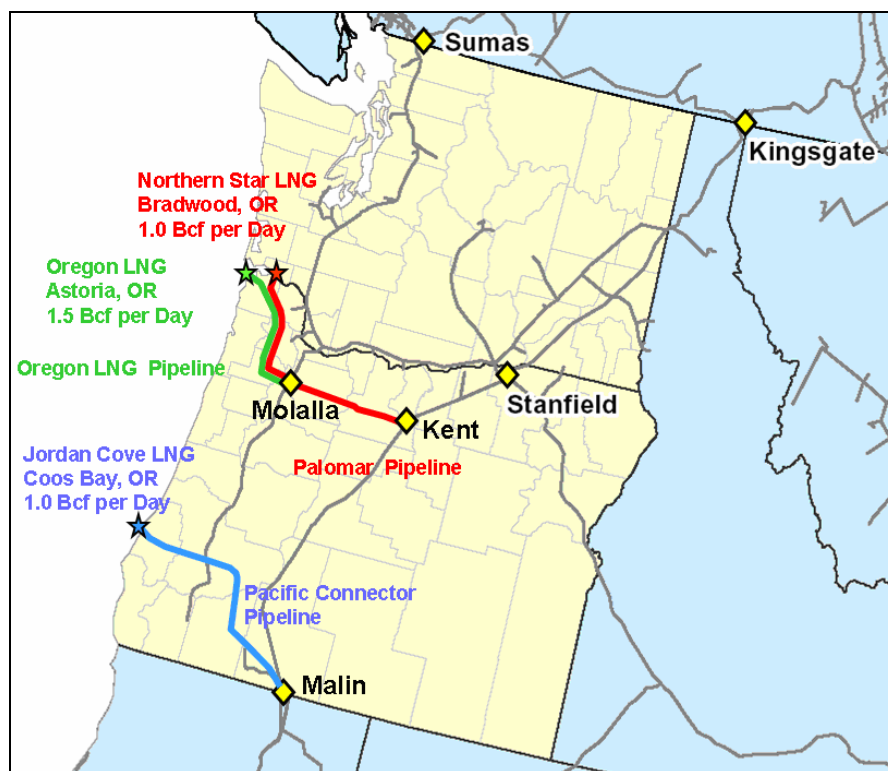
## Proposed LNG Terminals

There are currently three proposed LNG terminals for the Pacific Northwest (Exhibit 5.16). Two on the coast near the Washington / Oregon State border at Bradwood and Astoria, Oregon. The Jordan Cove location is further south near Coos Bay, Oregon. The proposed terminals range in size from 1 to 1.5 Bcf per day in maximum delivery capacity. All three terminals have an anticipated in-service date after 2011.

Each of the proposed terminals has an associated pipeline project. Two of the proposed pipelines would access markets outside the Pacific Northwest. The proposed Jordan Cove terminal would access California Markets directly through the Pacific Connector. The proposed Bradwood LNG would access markets to the south via GTN.

There is no guarantee that any LNG terminal will be built in the Pacific Northwest. None of the terminals are under construction. All have significant permitting and legal steps yet to take. In addition, international LNG supply must be procured in advance of any LNG terminal opening.

**Exhibit 5.16: Proposed LNG Import Terminals and Associated Pipeline Projects**



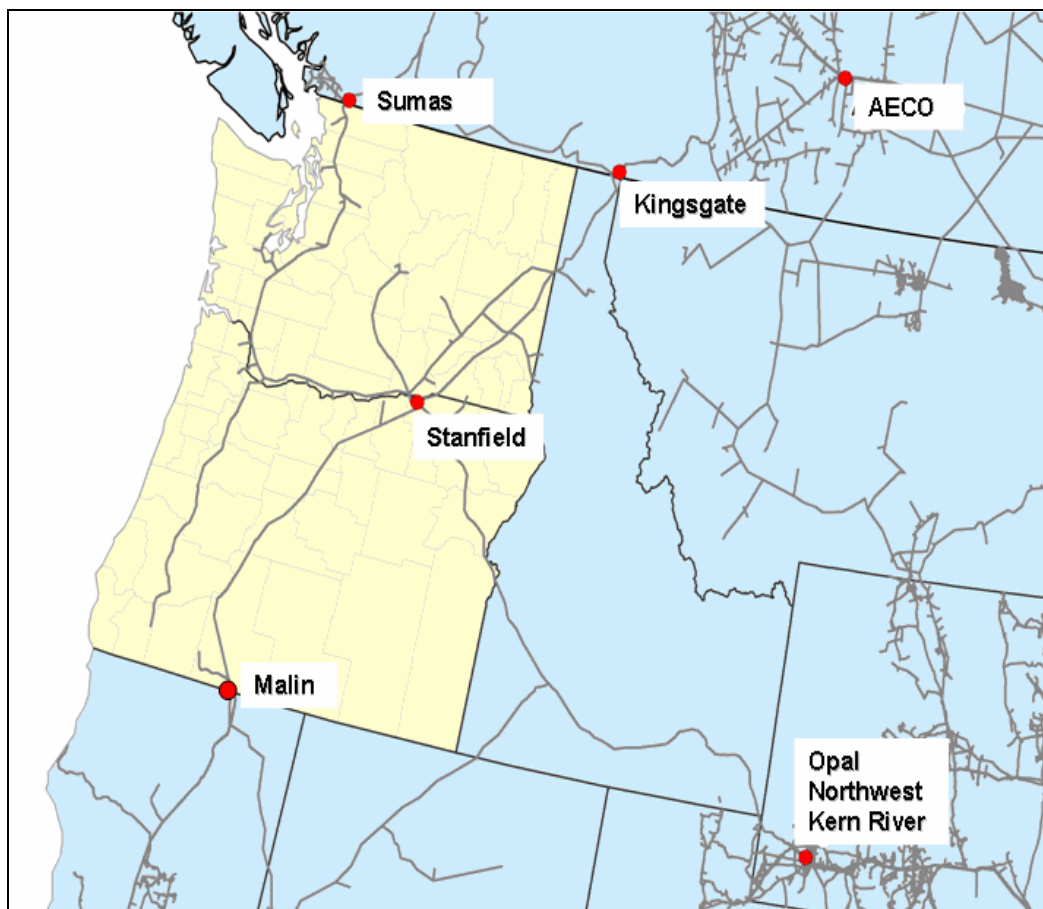
Source: ICF International

## Gas Pricing Points In and Near the Pacific Northwest

Most natural gas transactions throughout the U.S. and Canada occur at a relatively small number of pricing points often referred to as market centers. Western Oregon itself currently does not have a reported gas price index. Therefore, Oregon gas purchases must be indexed to nearby area pricing points upstream or downstream, such as Sumas at the Canadian Border or Malin Oregon at the border of California. The most widely referenced pricing points in the area are shown in Exhibit 5.17. The majority of gas transactions occur at the following locations:

- Northwest, Canadian Border (Sumas)
- GTN, Kingsgate
- Stanfield, Oregon
- PG&E Malin
- TCPL Alberta, AECO-C
- Opal Wyoming
  - Northwest Wyoming Pool
  - Kern River, Opal Plant

**Exhibit 5.17: Regional Pricing Points**



Source: Platts Gas Daily

#### *Northwest, Canadian Border (Sumas)*

The Sumas price index tracks transactions into Northwest Pipeline from BC pipeline (Westcoast Energy) at the Sumas Washington / Huntington, British Columbia interconnection at the U.S. / Canadian border. Transactions are reported in \$U.S. per MMBtu.

#### *GTN, Kingsgate*

The Kingsgate price index tracks transactions into Gas Transmission Northwest from Foothills Pipeline at the U.S. / Canadian border in Boundary County Idaho. Prior to August 1, 2004 the index was known as PG&E Gas Transmission Northwest. Transactions are reported in \$U.S. per MMBtu.

#### *Stanfield, Oregon*

The price index includes all transactions from GTN at the Stanfield compressor station in Umatilla County Oregon on the Oregon Washington Border.

#### *PG&E, Malin*

The price index includes all transactions into Pacific Gas and Electric's Lines 400 and 401 from Gas Transmission Northwest (formally PG&E Gas Transmission, Northwest) at the Oregon/ California Border at Malin, Oregon.

#### *TCPL Alberta, AECO-C*

The index includes deliveries into TransCanada's Alberta System at the AECO-C, Nova Inventory Transfer (NIT) Hub in southeastern Alberta. AECO-C is the principle storage facility and hub on TCPL Alberta. Prior to August 2004, the index was known as NOVA. The price is reported in \$Canadian per gigajoule.

#### *Northwest, Wyoming Pool*

The Northwest, Wyoming Pool is one of several pipeline indexes that report transactions in the Opal, Wyoming area. This index includes transactions that deliver gas into Northwest Pipeline from the Green River, Wyoming compressor station to the Kemmerer, Wyoming station. Included are deliveries at any of the following gas processing plants: Opal, Painter, Anschutz, Muddy Creek, Granger, Shute Creek, and Whitney Canyon.

#### *Kern River, Opal Plant*

The Kern River, Opal Plant price index tracks transactions into Kern River at the Opal, Wyoming processing plant and the Muddy Creek compressor station in southwestern Wyoming where Kern River connects with Northwestern, Questar, and Colorado Interstate Gas pipelines. Gas traded at the Opal plant that is not nominated into a specific pipeline is included in the price index.

## Long-term Projections for Natural Gas Prices and Basis

Exhibit 5.18 shows averages of annual prices for Henry Hub and basis from Henry Hub to the Pacific Northwest indices (Sumas, Malin, and Kingsgate), as well as basis from Henry Hub to AECO and Opal for the Base Case and all five scenarios through 2030. The table is broken down into six time periods: historical 2002-2007, predevelopment 2008-2010, development 2011-2015, post development 2016-2020, Alaska gas development 2021-2025, and long-term 2026-2030. The historical period should be used as a benchmark to gauge trend directions. All of the incremental Pacific Northwest natural gas infrastructure assumed in the five alternate scenarios has beginning in-service dates from 2011 to 2015 or the development period. Alaska is assumed to be in-service at the end of 2020 and expanded in 2023. There is a relatively large price and basis reduction for the region associated with this development. If the Alaska pipeline is not built, previous price and basis trends will most likely continue.

Relative to the Base Case, the basis trends for Malin and Kingsgate are similar to the trend for Sumas. Basis at Malin and Kingsgate are lower than the Base Case in both the Jordan Cove and the Ruby Pipeline scenarios, but the greatest impact on basis is in the Jordan Cove / Ruby case.

The impact on AECO basis is similar to the impact on the Pacific Northwest indices. At AECO, the reduction in basis is similar in the Jordan Cove 100 and 300, Ruby Pipeline and Ruby / Palomar cases, but the greatest reduction in basis is in the Jordan Cove / Ruby Case. At Opal, the dynamics are different. In the Base Case, Opal basis remains high and even increases, as pipeline capacity additions lag behind the development of new gas supplies in the Rockies. The addition of Jordan Cove alone has little impact on the Opal basis. In contrast, the cases which add Ruby Pipeline have a dramatic effect on Opal basis. The addition of Ruby Pipeline relieves pipeline constraints out of the Rockies, thereby raising prices at Opal and reducing the basis differential by as much as \$1.89 per MMBtu, compared to the Base Case.

**Exhibit 5.18: Projected Annual Natural Gas Prices for Henry Hub and Indexes near the Pacific Northwest 2000-2030 (\$'s per MMBtu)**

Years	Time Period
2002-2007	Historical
2008-2010	Predevelopment
2011-2015	Development of Pacific Northwest Supply Infrastructure
2016-2020	Post Development
2021-2025	Alaska Gas Development (assumed in all cases)
2026-2030	Long-term

Base Case						
Years	Henry Hub Price	Average Henry Hub Basis				
		Malin	Sumas	Kingsgate	AECO	Opal
2002-2007	\$ 6.19	\$ (0.63)	\$ (0.79)	\$ (0.84)	\$ (0.96)	\$ (1.49)
2008-2010	\$ 7.76	\$ (0.09)	\$ (0.16)	\$ (0.23)	\$ (0.31)	\$ (1.00)
2011-2015	\$ 9.97	\$ 0.14	\$ 0.06	\$ (0.04)	\$ (0.15)	\$ (3.60)
2016-2020	\$ 11.41	\$ 0.19	\$ 0.22	\$ (0.03)	\$ (0.16)	\$ (2.77)
2021-2025	\$ 11.10	\$ (0.56)	\$ (1.10)	\$ (1.12)	\$ (1.43)	\$ (2.04)
2026-2030	\$ 12.20	\$ 0.27	\$ (0.37)	\$ (0.46)	\$ (0.90)	\$ (4.16)
2011-2030	\$ 11.17	\$ 0.01	\$ (0.30)	\$ (0.41)	\$ (0.66)	\$ (3.14)

Jordan Cove 100						
Years	Henry Hub Price	Average Henry Hub Basis				
		Malin	Sumas	Kingsgate	AECO	Opal
2002-2007	\$ 6.95	\$ (0.46)	\$ (0.45)	\$ (0.74)	\$ (0.90)	\$ (2.84)
2008-2010	\$ 7.76	\$ (0.09)	\$ (0.16)	\$ (0.23)	\$ (0.31)	\$ (1.00)
2011-2015	\$ 9.76	\$ 0.04	\$ 0.00	\$ (0.08)	\$ (0.18)	\$ (3.49)
2016-2020	\$ 11.23	\$ (0.01)	\$ 0.03	\$ (0.09)	\$ (0.20)	\$ (2.61)
2021-2025	\$ 11.05	\$ (1.27)	\$ (1.53)	\$ (1.53)	\$ (1.78)	\$ (2.29)
2026-2030	\$ 12.14	\$ (0.39)	\$ (0.67)	\$ (0.69)	\$ (0.95)	\$ (3.74)
2011-2030	\$ 11.05	\$ (0.41)	\$ (0.54)	\$ (0.60)	\$ (0.78)	\$ (3.03)
Delta Base Case	\$ (0.12)	\$ (0.42)	\$ (0.24)	\$ (0.18)	\$ (0.12)	\$ 0.11

Jordan Cove 300						
Years	Henry Hub Price	Average Henry Hub Basis				
		Malin	Sumas	Kingsgate	AECO	Opal
2002-2007	\$ 6.95	\$ (0.46)	\$ (0.45)	\$ (0.74)	\$ (0.90)	\$ (2.84)
2008-2010	\$ 7.76	\$ (0.09)	\$ (0.16)	\$ (0.23)	\$ (0.31)	\$ (1.00)
2011-2015	\$ 9.76	\$ 0.07	\$ (0.02)	\$ (0.08)	\$ (0.18)	\$ (3.49)
2016-2020	\$ 11.23	\$ 0.01	\$ (0.04)	\$ (0.10)	\$ (0.21)	\$ (2.61)
2021-2025	\$ 11.05	\$ (1.27)	\$ (1.54)	\$ (1.54)	\$ (1.78)	\$ (2.29)
2026-2030	\$ 12.14	\$ (0.39)	\$ (0.69)	\$ (0.70)	\$ (0.95)	\$ (3.74)
2011-2030	\$ 11.05	\$ (0.39)	\$ (0.57)	\$ (0.60)	\$ (0.78)	\$ (3.03)
Delta Base Case	\$ (0.12)	\$ (0.41)	\$ (0.28)	\$ (0.19)	\$ (0.12)	\$ 0.11

Ruby Pipeline						
Years	Henry Hub Price	Average Henry Hub Basis				
		Malin	Sumas	Kingsgate	AECO	Opal
2002-2007	\$ 6.95	\$ (0.46)	\$ (0.45)	\$ (0.74)	\$ (0.90)	\$ (2.84)
2008-2010	\$ 7.76	\$ (0.09)	\$ (0.16)	\$ (0.23)	\$ (0.31)	\$ (1.00)
2011-2015	\$ 9.82	\$ (0.03)	\$ 0.01	\$ (0.09)	\$ (0.19)	\$ (0.82)
2016-2020	\$ 11.19	\$ (0.06)	\$ 0.15	\$ (0.10)	\$ (0.21)	\$ (1.28)
2021-2025	\$ 11.05	\$ (1.21)	\$ (1.45)	\$ (1.45)	\$ (1.66)	\$ (1.71)
2026-2030	\$ 12.18	\$ (0.52)	\$ (0.75)	\$ (0.80)	\$ (1.04)	\$ (1.21)
2011-2030	\$ 11.06	\$ (0.45)	\$ (0.51)	\$ (0.61)	\$ (0.77)	\$ (1.26)
Delta Base Case	\$ (0.11)	\$ (0.47)	\$ (0.21)	\$ (0.19)	\$ (0.11)	\$ 1.89

Jordan Cove and Ruby Pipeline						
Years	Henry Hub Price	Average Henry Hub Basis				
		Malin	Sumas	Kingsgate	AECO	Opal
2002-2007	\$ 6.95	\$ (0.46)	\$ (0.45)	\$ (0.74)	\$ (0.90)	\$ (2.84)
2008-2010	\$ 7.76	\$ (0.09)	\$ (0.16)	\$ (0.23)	\$ (0.31)	\$ (1.00)
2011-2015	\$ 9.63	\$ (0.13)	\$ (0.06)	\$ (0.11)	\$ (0.21)	\$ (0.84)
2016-2020	\$ 11.03	\$ (0.25)	\$ (0.11)	\$ (0.14)	\$ (0.25)	\$ (1.27)
2021-2025	\$ 11.04	\$ (1.76)	\$ (1.99)	\$ (1.96)	\$ (2.12)	\$ (2.12)
2026-2030	\$ 12.14	\$ (0.79)	\$ (1.04)	\$ (1.03)	\$ (1.19)	\$ (1.32)
2011-2030	\$ 10.96	\$ (0.73)	\$ (0.80)	\$ (0.81)	\$ (0.94)	\$ (1.39)
Delta Base Case	\$ (0.21)	\$ (0.74)	\$ (0.50)	\$ (0.40)	\$ (0.28)	\$ 1.76

Ruby Pipeline and Palomar Pipeline						
Years	Henry Hub Price	Average Henry Hub Basis				
		Malin	Sumas	Kingsgate	AECO	Opal
2002-2007	\$ 6.95	\$ (0.46)	\$ (0.45)	\$ (0.74)	\$ (0.90)	\$ (2.84)
2008-2010	\$ 7.76	\$ (0.09)	\$ (0.16)	\$ (0.23)	\$ (0.31)	\$ (1.00)
2011-2015	\$ 9.82	\$ (0.03)	\$ (0.04)	\$ (0.09)	\$ (0.19)	\$ (0.82)
2016-2020	\$ 11.19	\$ (0.06)	\$ (0.09)	\$ (0.10)	\$ (0.21)	\$ (1.28)
2021-2025	\$ 11.06	\$ (1.22)	\$ (1.50)	\$ (1.47)	\$ (1.68)	\$ (1.72)
2026-2030	\$ 12.18	\$ (0.51)	\$ (0.82)	\$ (0.81)	\$ (1.05)	\$ (1.21)
2011-2030	\$ 11.06	\$ (0.45)	\$ (0.61)	\$ (0.62)	\$ (0.78)	\$ (1.26)
Delta Base Case	\$ (0.11)	\$ (0.47)	\$ (0.31)	\$ (0.20)	\$ (0.12)	\$ 1.89

Source: ICF International

Exhibit 5.19 shows January prices for Henry Hub and January basis between Henry Hub and the five indices for the Base Case and all five scenarios through 2030. All five scenarios reduce January basis at all the indices, but the impacts on basis differ both among the alternate scenarios and the indices. The Jordan Cove / Ruby case had the greatest impact on January basis at Sumas, Kingsgate and Malin from 2011 to 2030, relative to the base case.

The Ruby, Jordan Cove / Ruby, and Ruby / Palomar cases all have similar impacts on Opal's January basis. All three of these cases include the Ruby pipeline, which relieves pipeline constraints out of the Rockies and thereby raises Opal prices and reduced basis by an average of nearly \$3.00 per MMBtu between 2011 and 2030. The Jordan Cove cases have relatively little impact on prices at Opal, since this case provides no additional pipeline capacity out of the Rockies.

All of the scenarios reduced the 2011 to 2030 average January basis differential at AECO (that is, it became less negative), but the impacts on AECO basis are relatively small compared to the impacts on other indices.

**Exhibit 5.19: Projected January Natural Gas Prices for Henry Hub and Indexes near the Pacific Northwest 2000-2030 (\$'s per MMBtu)**

<b>Base Case</b>						
Years	Henry Hub Price	Average Henry Hub Basis				
		Malin	Sumas	Kingsgate	AECO	Opal
2002-2007	\$ 5.83	\$ (0.46)	\$ (0.50)	\$ (0.73)	\$ (0.76)	\$ (0.95)
2008-2010	\$ 8.25	\$ (0.20)	\$ 0.07	\$ (0.34)	\$ (0.46)	\$ (0.80)
2011-2015	\$ 10.51	\$ 0.32	\$ 0.48	\$ 0.15	\$ 0.05	\$ (3.47)
2016-2020	\$ 12.33	\$ 0.42	\$ 1.36	\$ 0.21	\$ 0.09	\$ (3.65)
2021-2025	\$ 12.29	\$ (0.28)	\$ (0.44)	\$ (0.87)	\$ (1.91)	\$ (2.01)
2026-2030	\$ 13.65	\$ 0.35	\$ 0.13	\$ (0.35)	\$ (1.83)	\$ (7.97)
2011-2030	\$ 12.19	\$ 0.20	\$ 0.38	\$ (0.22)	\$ (0.90)	\$ (4.27)

<b>Jordan Cove 100</b>						
Years	Henry Hub Price	Average Henry Hub Basis				
		Malin	Sumas	Kingsgate	AECO	Opal
2002-2007	\$ 5.83	\$ 0.04	\$ 0.18	\$ (0.13)	\$ (0.49)	\$ (0.45)
2008-2010	\$ 8.25	\$ (0.20)	\$ 0.07	\$ (0.34)	\$ (0.46)	\$ (0.80)
2011-2015	\$ 10.32	\$ 0.08	\$ 0.43	\$ 0.11	\$ 0.02	\$ (3.36)
2016-2020	\$ 12.16	\$ (0.05)	\$ 0.59	\$ 0.18	\$ 0.06	\$ (3.46)
2021-2025	\$ 12.23	\$ (0.65)	\$ (0.78)	\$ (1.17)	\$ (1.96)	\$ (2.20)
2026-2030	\$ 13.59	\$ (0.13)	\$ (0.19)	\$ (0.57)	\$ (1.13)	\$ (6.21)
2011-2030	\$ 12.08	\$ (0.19)	\$ 0.01	\$ (0.36)	\$ (0.75)	\$ (3.81)
Delta Base Case	\$ (0.12)	\$ (0.39)	\$ (0.38)	\$ (0.15)	\$ 0.15	\$ 0.47

<b>Jordan Cove 300</b>						
Years	Henry Hub Price	Average Henry Hub Basis				
		Malin	Sumas	Kingsgate	AECO	Opal
2002-2007	\$ 5.83	\$ 0.04	\$ 0.18	\$ (0.13)	\$ (0.49)	\$ (0.45)
2008-2010	\$ 8.25	\$ (0.20)	\$ 0.07	\$ (0.34)	\$ (0.46)	\$ (0.80)
2011-2015	\$ 10.32	\$ 0.19	\$ 0.32	\$ 0.10	\$ 0.01	\$ (3.37)
2016-2020	\$ 12.17	\$ 0.04	\$ 0.42	\$ 0.12	\$ 0.01	\$ (3.46)
2021-2025	\$ 12.23	\$ (0.64)	\$ (0.85)	\$ (1.17)	\$ (1.97)	\$ (2.20)
2026-2030	\$ 13.59	\$ (0.11)	\$ (0.26)	\$ (0.64)	\$ (1.17)	\$ (6.21)
2011-2030	\$ 12.08	\$ (0.13)	\$ (0.09)	\$ (0.40)	\$ (0.78)	\$ (3.81)
Delta Base Case	\$ (0.12)	\$ (0.34)	\$ (0.48)	\$ (0.18)	\$ 0.12	\$ 0.47

<b>Ruby Pipeline</b>						
Years	Henry Hub Price	Average Henry Hub Basis				
		Malin	Sumas	Kingsgate	AECO	Opal
2002-2007	\$ 6.33	\$ 0.04	\$ 0.18	\$ (0.13)	\$ (0.49)	\$ (0.45)
2008-2010	\$ 8.25	\$ (0.20)	\$ 0.07	\$ (0.34)	\$ (0.46)	\$ (0.80)
2011-2015	\$ 10.39	\$ (0.08)	\$ 0.46	\$ 0.13	\$ 0.04	\$ (0.79)
2016-2020	\$ 12.09	\$ (0.16)	\$ 1.30	\$ 0.18	\$ 0.07	\$ (1.49)
2021-2025	\$ 12.23	\$ (0.91)	\$ (0.96)	\$ (1.33)	\$ (1.96)	\$ (1.47)
2026-2030	\$ 13.61	\$ (0.55)	\$ (0.44)	\$ (0.93)	\$ (1.44)	\$ (1.49)
2011-2030	\$ 12.08	\$ (0.42)	\$ 0.09	\$ (0.49)	\$ (0.82)	\$ (1.31)
Delta Base Case	\$ (0.11)	\$ (0.63)	\$ (0.30)	\$ (0.27)	\$ 0.08	\$ 2.96

<b>Jordan Cove and Ruby Pipeline</b>						
Years	Henry Hub Price	Average Henry Hub Basis				
		Malin	Sumas	Kingsgate	AECO	Opal
2002-2007	\$ 6.33	\$ 0.04	\$ 0.18	\$ (0.13)	\$ (0.49)	\$ (0.45)
2008-2010	\$ 8.25	\$ (0.20)	\$ 0.07	\$ (0.34)	\$ (0.46)	\$ (0.80)
2011-2015	\$ 10.22	\$ (0.14)	\$ 0.33	\$ 0.10	\$ 0.01	\$ (0.80)
2016-2020	\$ 11.96	\$ (0.28)	\$ 0.44	\$ 0.10	\$ (0.01)	\$ (1.46)
2021-2025	\$ 12.20	\$ (1.37)	\$ (1.51)	\$ (1.71)	\$ (2.11)	\$ (1.74)
2026-2030	\$ 13.61	\$ (0.89)	\$ (0.84)	\$ (1.16)	\$ (1.33)	\$ (1.60)
2011-2030	\$ 12.00	\$ (0.67)	\$ (0.39)	\$ (0.67)	\$ (0.86)	\$ (1.40)
Delta Base Case	\$ (0.20)	\$ (0.87)	\$ (0.78)	\$ (0.45)	\$ 0.04	\$ 2.87

<b>Ruby Pipeline and Palomar Pipeline</b>						
Years	Henry Hub Price	Average Henry Hub Basis				
		Malin	Sumas	Kingsgate	AECO	Opal
2002-2007	\$ 6.33	\$ 0.04	\$ 0.18	\$ (0.13)	\$ (0.49)	\$ (0.45)
2008-2010	\$ 8.25	\$ (0.20)	\$ 0.07	\$ (0.34)	\$ (0.46)	\$ (0.80)
2011-2015	\$ 10.39	\$ (0.07)	\$ 0.35	\$ 0.13	\$ 0.04	\$ (0.79)
2016-2020	\$ 12.10	\$ (0.15)	\$ 0.28	\$ 0.18	\$ 0.06	\$ (1.49)
2021-2025	\$ 12.23	\$ (0.89)	\$ (1.11)	\$ (1.33)	\$ (1.96)	\$ (1.45)
2026-2030	\$ 13.61	\$ (0.50)	\$ (0.69)	\$ (1.06)	\$ (1.53)	\$ (1.47)
2011-2030	\$ 12.08	\$ (0.40)	\$ (0.29)	\$ (0.52)	\$ (0.85)	\$ (1.30)
Delta Base Case	\$ (0.11)	\$ (0.60)	\$ (0.68)	\$ (0.30)	\$ 0.05	\$ 2.97

Source: ICF International