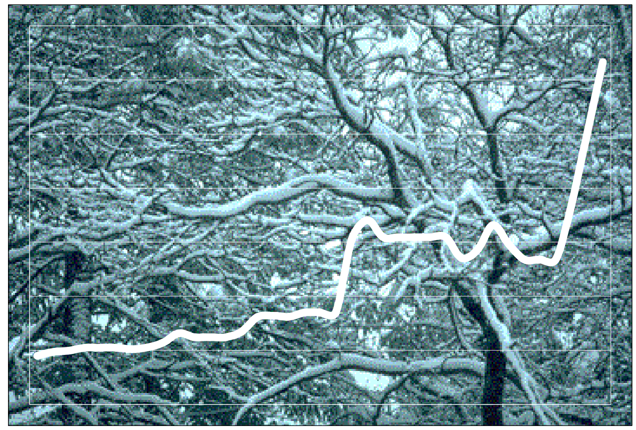
A REPORT TO THE
OREGON OFFICE OF ENERGY



Oregon Energy Outlook

December 31, 2000

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Executive Summary

I. Overview

The surging energy prices of the past year and apprehensions about energy shortages have been unsettling. What makes this even more troubling is that it reaches across all energy resources: electricity, natural gas, and petroleum.

Energy prices have increased across the nation:

- The price of domestic crude oil averaged at about $30 per barrel in July 2000 - a 65% increase over the same time last year – and the price has been holding near that level.
- The national average price of home heating oil was $1.56 per gallon in November 2000 - an increase of 52% over November 1999.
- The national urban average retail price for unleaded regular gasoline peaked at $1.71 per gallon in June 2000 - a 47% increase over June 1999.
- Spot wellhead prices for natural gas for most of September through early December were above $5 per million BTUs, more than double the price of one year ago and recent spot prices approached $9.

In Oregon, and the western region, prices mirrored the nation and in the case of electricity far exceeded the national average increases.

- Wholesale electricity prices in the region increased by as much as thirty-fold.
- Wholesale natural gas prices at the Sumas, Washington delivery point started 2000 at $2.28 per million BTUs and ended the year at $10.96 per million BTUs, but in between hit $42.30.
- Home heating oil prices in Oregon averaged $1.56 in November 2000 – a 50 percent increase over November 1999.

- Oregon AAA reported average Oregon gasoline prices of $1.75 in September 2000, up from $1.53 one year ago and $1.19 two years ago.

While the causes are complex, the fundamental issue is that with the strong economy of recent years, the demand for energy has grown and the supply of energy has not kept pace. The market is responding with higher prices. All energy resources used by Oregonians are near capacity. A severe Arctic cold front settling in on the Pacific Northwest, disruptions in the supply or delivery systems, or other problems could result in energy shortages.

The interrelationship of the energy resources and the interconnection with other states make the dynamics more complex. Natural gas is used not only for heating and industrial processes, but also to produce electricity. Heating oil is used not only for heating and industrial processes, but also as a back up to natural gas used in industrial processes and to run back up generators for electricity.

The interconnection of energy markets means that national and international markets influence energy prices and supplies in Oregon. The relationship between states has been affirmed as California's problems have become ours. But decisions by the Organization of Petroleum Exporting Countries (OPEC) to reduce production have also had a direct effect on energy prices in Oregon.

Over the past few years, there have been fundamental changes in the energy marketplace. All energy resources are now wholesale commodities subject to competitive market pressures. Because regulated retail rates for electricity and natural gas are not as dynamic as the marketplace, Oregonians have not yet paid the full market price for the energy they are using. There will be more rate increases.

Over the near term, the market will continue to be volatile. The interrelationship between the energy resources, the interconnection between states, and an energy supply and delivery system that has little surplus capacity mean that we are entering a period of risk and uncertainty.

That point gained meaning in December 2000 with Oregon Governor John Kitzhaber and Washington Governor Gary Locke calling for regional conservation to avert potential electricity shortages and U.S. Energy Secretary Bill Richardson taking the unprecedented action of ordering power generators and marketers in the west to ship electricity to California. While these actions responded to the imminent crisis, they did not and could not resolve the underlying problems that will challenge Oregon for years to come.

The report on the ***Oregon Energy Outlook*** offers a review of the changing energy markets and of what those changes mean for Oregonians.

II. What is the Oregon Energy Outlook?

The ***Oregon Energy Outlook*** offers an assessment of energy markets and trends to provide a framework for informed decision-making and appropriate responses to energy events. Such a framework is achieved only by understanding the energy markets and the forces that act upon them.

Energy supplies are generally adequate to meet the needs of Oregonians. Certain conditions, such as extended severe cold weather, could lead to supply problems and require the purchase of energy supplies at very high prices. Voluntary reductions in use will go a long way in easing the problem. No forced curtailment of "firm" utility service is foreseen unless several adverse circumstances happen at the same time. However, customers on "interruptible" service should expect interruptions.

A. Electricity

In 1997, electricity was 22 percent of Oregon's energy use. Oregon's electricity use grew by about 11 percent from 1990 through 1997.

There have been fundamental changes in the electricity market. The nation, including Oregon, has steadily moved towards restructuring the way electricity is bought and sold. Restructuring, or "deregulation," did not get off to a good start. California, which led the nation in the march to restructuring, experienced massive problems when the electrical system came under pressure. The California system came very close to failure to meet loads and caused wholesale electricity prices to soar. Prices increased thirty fold.

Because California is interconnected to the western electrical system, California's problem reverberated throughout the West. This exposed problems with the electrical system that we had been lulled into ignoring. The surplus of power resources is gone now. The system is at the mercy of conditions that we cannot control such as weather, stream flows, and California markets.

A study by the Northwest Power Planning Council found that there is roughly one chance in four that the electrical system will not be able to meet load over the next three years if no resources are added beyond what is already under construction. In the current environment, market forces should signal developers to build needed capacity. But that will take time and it is not clear whom, if anyone, has responsibility to ensure that sufficient generation and transmission resources will be built should the marketplace fail to do so. The large majority of planned generating resources is proposed by non-utility entities. Their focus is on recovering investments and making a profit as opposed to ensuring adequate power supply and system reliability.

Market volatility will remain as long as demand is increasing and system capacity is at its limit. Electricity prices in the long term are on an upward trend. Most of the proposed generation will be fueled by natural gas. That will put upward pressure on the price of natural gas. Rising natural gas prices will in turn influence electricity prices. Over the next two years, wholesale electricity prices will be volatile and on the upswing. Retail electricity rates are regulated by the Oregon Public Utility Commission (OPUC) for investor-owned utilities or set by publicly-owned utilities or local cooperatives. Rates for those publicly-owned utilities and local cooperatives largely influenced by the rates of Bonneville Power Administration (BPA), which are subject to regulatory review. For that reason, retail rates will not be as volatile as wholesale prices, but sustained high wholesale prices will push retail rates up.

The interrelationship between the energy resources, the interconnection between states, and an energy supply and delivery system that has little surplus capacity mean that we are entering a period of risk and uncertainty. That risk and uncertainty was given meaning in December 2000.

On December 8, Oregon Governor John Kitzhaber and Washington Governor Gary Locke asked citizens in their states to conserve electricity in anticipation of a severe cold front expected the following week. They took that action because of concern that tight electricity supplies could not meet the demands imposed by the cold weather. The regional warning of a potential power shortage was withdrawn the following week as the threat of the cold front diminished and actions to reduce demand were effective. But another threat soon emerged.

On December 13, Secretary Richardson took the unprecedented action of ordering power generators and marketers in the west to ship electricity to California.

On December 14, Governor Kitzhaber called upon Secretary Richardson and Jim Hoecker, Chairman of the Federal Energy Regulatory Commission (FERC), to convene an energy summit in the west to deal with the growing crisis. In part, Governor Kitzhaber's concern was based on the knowledge that the Pacific Northwest, already confronting potential shortage, has historically *imported* power from California during the winter heating season.

On December 20, the regional energy summit was held in Denver, Colorado. At the summit were five Western governors, including Oregon Governor John Kitzhaber, and Energy Secretary Richardson, FERC Chairman Hoecker, representatives of electric and gas utilities, electric power producers, and other state and federal officials. The summit focused on building an understanding of regional energy issues and achieving agreement on short-term actions, including aggressive conservation and regional cooperation. The Governors will meet again in late January or early February to discuss longer-term solutions to the energy problems.

Secretary Richardson's order was to end on December 20, but on that day, the Secretary extended the order until December 28, saying that the circumstances that caused him to issue the initial order continued. On December 28, he again extended the order, this time until January 5.

Events in December 2000 highlighted the risk and uncertainty confronting the western states, including Oregon. The actions taken respond to the imminent crisis, but do not resolve the underlying problems that will challenge Oregon for years to come.

B. Natural Gas

In 1997, 19 percent of Oregon's energy use was natural gas. Oregon's natural gas use grew by about 48 percent from 1990 through 1997.

North America has a vast and diverse natural gas resource base. The cost of finding that gas has been decreasing due to technological improvement. Yet, this year the wholesale commodity price of natural gas increased tenfold in a matter of three months at western delivery points. For many years, gas was abundant and the price was low. As a result, exploration and drilling activity dwindled. The economy was strong and growing and so was demand. The price of oil, an alternate fuel for natural gas, went up. The gas surplus was used up. Prices surged. Drilling activity picked up. Relief will come once the gas produced from new drilling activity reaches the market, but that will take time.

One of the prime reasons for the high prices is that the nation started the heating season with low inventories in storage. A major cause of the low inventories is the increased use of natural gas to produce electricity. This problem will be with us for a long time. Electricity producers bid up the price of natural gas when they fired up gas-fueled generation to deal with the power problems in California. That came at the time gas utilities normally purchase gas to put in storage. Many natural gas utilities waited for the prices to go down. Prices did not go down and storage remains short. In December 2000, storage was 33 percent below the five-year average in the West Region. This illustrates how the markets for the major energy sources have become interconnected.

Natural gas use for electrical generation is one the biggest factors in both natural gas and electricity markets. The Energy Information Administration (EIA) estimates that 120,645 megawatts of gas-fueled generation will be added nationwide over the next four years. That is more than three times the size of the Pacific Northwest regional power system. This will have a significant impact on the generation industry and will put added pressure on natural gas prices.

No shortages are expected for natural gas customers on firm service, which includes residential customers and most business. Firm service customers are those customers who have not chosen to receive lower rates in return for interruptible service and whose needs will be met by the utility providing the service. But prices will be higher. All three Oregon natural gas utilities had rate increases of over 20 percent earlier this year. This was to reflect wholesale price increases earlier in the year. We have yet to see the impact of the larger wholesale price increases that took place late in the year. If we experience a long cold winter, the impact on retail rates will be large.

Interruptible loads will be interrupted. This may lead to problems in petroleum markets, again illustrating the interconnection among energy markets. Customers with interruptible service and dual fuel capability may seek to substitute fuel oil for natural gas. This could be the same oil used to heat homes and buildings. That will lead to instability in an already tight heating oil market and drive prices upward.

C. Petroleum

Oregon uses more petroleum than any other energy resource. In 1997, petroleum was 47 percent of Oregon's energy use. Oregon's petroleum consumption grew by about 8 percent from 1990 through 1997.

Crude oil prices, which are the largest part of refined product prices, increased by 65% in the course of one year. In Oregon, the result was increases of 50% and 14% in the prices of home heating oil and gasoline respectively in 2000 compared to 1999 and even more when compared to 1998.

The increase was the result of the standard cycle for oil. Crude oil prices were depressed after the economic crisis in Asia and went as low as $10 per barrel. Exploration and drilling activity were curtailed, and the surplus of oil in storage increased. Then the Asian economy recovered. The economic recovery in Asia, coupled with a strong western economy, consumed surplus. In the meantime, the Organization of Petroleum Exporting Countries (OPEC), which has been trying to control the market by controlling supplies, managed to do so. This drove prices above $30 per barrel.

OPEC will be the major player in the market for a long time to come, because it controls the majority of remaining world oil reserves. U.S. production peaked in 1970, and the U.S. now imports half of the oil it consumes. OPEC will continue to try to control the supply of oil but will not let the price go too high. Oil prices over the next few years are expected to trade in the $25 to $35 per barrel range, holding prices for refined products near the levels now being experienced.

Oregon has no known petroleum resources and no refineries. Oregon gets most of its refined petroleum products from refineries in Washington. These refineries get their crude oil supply from Alaska through a 600-mile pipeline. There is concern about the reliability of the pipeline because of the harsh environment. A disruption in the oil supply to the refineries would cause severe problems for Oregonians. Refineries are operating at capacity and storage is minimal. Any disruption to refinery operations likely would have an immediate adverse impact, constraining supplies and increasing costs.

Heating oil and gasoline prices are expected to decline slightly over the next two years. However, volatility still looms in these markets. While most Oregon businesses have assured natural gas delivery through their natural gas utility, some larger industries have chosen instead to buy interruptible natural gas in return for lower prices. If the larger industries with interruptible contracts attempt to replace their interrupted gas supplies with fuel oil, that will reduce the supply available for home heating and drive up the price. And, when refineries try to boost the production of fuel oil to meet increased demand, they would produce less gasoline. This would lead to higher gasoline prices.

III. What does the Energy Outlook mean for Oregonians?

A. Oregonians at Home

Oregonians will pay higher costs for energy, costs that most have yet to see. In their homes, Oregonians use the most energy for winter heating. The coldest months are December, January, and February. The heating bills for those months will bring unwelcome news of rising energy costs. For Oregonians who heat with oil, the message of rising energy costs was delivered when they first filled their heating oil tanks for the winter. By October of this year, heating oil prices were up almost 50 percent over last winter.

Oregonians who heat their homes with electricity or natural gas will see their bills grow as rate increases show up in winter heating bills. Even those rate increases do not yet account for all of the additional costs of electricity and natural gas being purchased by utilities in the marketplace. More rate increases are likely in 2001.

For Oregonians most in need, those rising energy costs will be a hardship. That hardship will be tempered by additional funding for low-income energy assistance. The Oregon Department of Housing and Community Services will have $5 million more to help customers of Portland General Electric and Pacific Power. That money will be collected from the ratepayers of those utilities as the result of a 1999 Oregon law moving Oregon toward a competitive electricity market. Under that law, publicly-owned utilities will be required to offer a bill assistance program for household that qualify for federal low income energy assistance. Another $3.5 million was added to Low Income Energy Assistance by the federal government in September 2000 in response to rising heating oil prices. This is emergency assistance and cannot be expected in the future. Even with the additional money, the Oregon Department of Housing and Community Services acknowledges there will not be enough to help all Oregonians who will need help.

For Oregon households, tight energy supplies bring the possibility of curtailments in the event of unusually cold weather or supply disruptions.

B. Oregonians at Work

For Oregon's businesses, there are difficult times ahead. Oregon's jobs are produced primarily by small businesses. Most small businesses have firm energy contracts with a high level of assurance that energy will be delivered. But even they will struggle with rising energy prices. For them, rising energy costs and an economic downturn will make survival even more challenging, in a segment of the economy where survival is the exception.

For larger businesses, the market dynamics are more complex. Rising prices, potential supply constraints, and energy purchasing choices made by those businesses may all impose costs. Those conditions combined with a downturn in the economy will affect not only those businesses, but also Oregonians who will lose or already have lost their jobs. Job losses may not be widespread, but that will be little consolation to those who lose their jobs. Any job losses will be particularly hard-felt in rural Oregon.

C. Choices

While their choices are few, Oregonians do have choices. They can use less energy in their homes and their businesses. They can reduce their peak electricity use. They can pursue new local resources for electricity production and energy infrastructure, but both will impose economic and environmental costs.

IV. Energy Supplier Perspectives: Responding to the Changing Energy Market

The energy suppliers and state agencies participating in the review were asked to share perspectives on actions needed to respond to the changing energy markets. All shared information that was reflected in the report, but the energy suppliers offered other perspectives as well.

Some utilities sought state leadership in facilitating energy solutions, ensuring timely regulatory reviews, and completing a comprehensive review of issues associated with the move toward competitive markets. New incentive rates to manage loads and the use of industrial back up generators to create a virtual electricity plant are new approaches being pursued. Pursuing direct use of natural gas for space and water heating and use of refinery by-products to fuel industrial processes are among the concepts proposed.

The Appendix includes a more detailed description of written comments offered by three utilities. ***Oregon Energy Outlook*** presents these perspectives to stimulate further discussion of response actions.

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Report

The report first offers an assessment of energy markets and trends – the Energy Outlook for Oregon. Then it explores what the assessment means for Oregonians both at home and at work. Finally the report offers perspectives shared by energy suppliers on further actions to respond to the changing energy market.

I. What is the Oregon Energy Outlook?

A. Context

The assessment explains energy markets and trends. It describes the reasons behind the unsettling energy price increases and the supply constraints that contributed to those price increases.

The objective of the assessment is to provide a framework for informed decision-making and appropriate responses to energy events as they unfold. Such a framework is achieved only by understanding the energy markets and the forces that act upon these markets yielding the outcomes being seen. The assessment is structured to provide a basic understanding about these markets.

The assessment starts out with an examination of recent trends in energy prices. The markets for electricity, natural gas, and petroleum products are then reviewed. The supply and price outlook for each energy resource is then presented.

B. Recent Trends in Energy Prices

In 2000, Oregon and the nation have faced unprecedented increases in energy prices. The uniqueness of the situation is not only in the magnitude of the price increases, but also in the sweep across all the energy resources both nationally and in the western states, including Oregon. Why have the prices gone up so much and in all fuels? The following sections will answer those questions.

C. Energy Markets

The energy markets that Oregon depends upon have been transformed over the past decade.

In the electricity and natural gas markets, the changes are fundamental, as the market has undergone structural changes. For petroleum products, the changes are the result of the usual mix of global economics, Middle East politics, and attempts at market control. Each of these major markets will be described in enough detail to offer a basic understanding of what has happened in these markets.

1. Electricity

The electrical system serving Oregon has three components: generation, transmission, and distribution. The generation component is where electricity is produced at power generating facilities. Electrical generation in 11 western states and two Canadian provinces serves Oregonians. In Oregon and the region, the predominant resource is hydroelectric, with significant resources produced by coal-fired generation. While smaller generation resources are being developed, such as electricity produced by wind turbines, natural gas is the dominant fuel for new generation facilities.

The transmission component is the high voltage network that carries the electricity from generation throughout the western states to distribution facilities. On interconnected systems, the transmission component also links a utility to other utilities from which resources may be acquired.

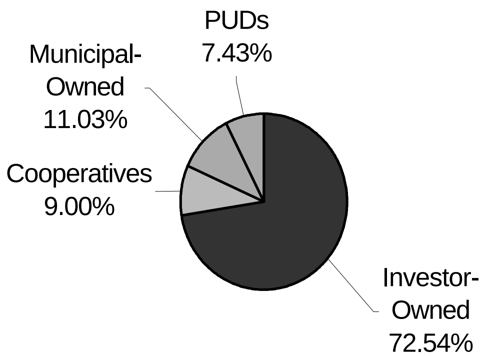
The distribution component is what connects the end user to the distribution center (called a major substation). The substations step down the voltage from the transmission high levels to levels appropriate for local distribution. Additional transformers step voltage down to levels usable by the consumer.

a. Oregon's Electricity System

In 1997, 22 percent of Oregon's energy use was electricity. Oregon's electricity use grew by about 11 percent from 1990 through 1997.

There are 39 electric utilities in Oregon. Three of these utilities are investor-owned that serve close to three-quarters of the state's need from generation resources they mostly own (see Figure 1). Less than half of these generating plants are within Oregon's borders. The remaining 36 utilities are publicly-owned or consumer owned and serve about a quarter of the state's customers and own a small portion of generation resources. BPA, which markets power generated by the federal hydroelectric system, provides most of the electricity distributed by the publicly-owned utilities. The BPA also serves directly a few large industrial customers in Oregon.

Electricity Sold in Oregon by Type of Utility (1999)
Figure 1



Source: Oregon Public Utility Commission Statistics

The generation and transmission components that Oregon utilities rely on are parts of regional systems that are coordinated to minimize costs.

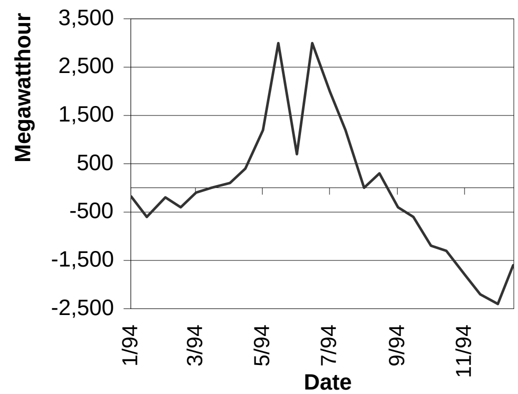
For power generation, Oregon is part of the Pacific Northwest regional power system as defined by the Pacific Northwest Electric Power Planning and Conservation Act. This system includes Oregon, Washington, Idaho, Montana west of the Continental Divide, and portions of Nevada, Utah, and Wyoming that lie within the Columbia River drainage basin. The common bond to utilities comprising this system is the benefit drawn from the regional hydroelectric generation system and the coordination of its operation.

Oregon utilities are also a part of the western transmission grid. This interconnected system, called the Western Systems Coordinating Council (WSCC) links utilities and power suppliers in all 11 western states and the Canadian provinces of British Columbia and Alberta. Being linked to this system allows utilities to buy, sell and exchange power, taking advantage of diversity of both loads and resources among the participants.

This is very important to utilities in Oregon and the regional system. The reason is that the Pacific Northwest and California have their greatest need for power during different times of the year. California's needs peak in the summer because of the air conditioning load, while the Northwest's needs peak in the winter for space heating. Instead of each system building resources to meet its peak, the two systems take advantage of this "peak diversity" by exchanging or buying power from each other. Oregon has historically relied in part on California's resources to help meet its loads in the winter, just as California has relied on resources from the Pacific Northwest to meet its needs in the summer. This is especially true when hydro generation is limited because of low river stream flows (see Figure 2).

Also, the Pacific Northwest sells a considerable amount of surplus power to California utilities. This surplus results from the way the Pacific Northwest plans and operates the hydro system. Because stream flows vary widely from year-to-year, only power that can be generated from the most adverse stream flows on record can be counted on year in year out. Since the Pacific Northwest rarely encounters this worst case, the system will have some surplus electricity each year. California is a ready and willing market for this power. Surplus sales generate revenues that benefit consumers in the Pacific Northwest.

Power Sales To and From California (1994)
Figure 2



Source: Compiled from Bonneville Power Administration intertie data.

b. Prices

Retail electricity prices are generally based on the cost of producing and delivering power to consumers (cost of service). For Investor-Owned Utilities (IOUs), retail rates are set by the OPUC, based on the average cost of producing and delivering electricity to customers and a reasonable rate of return. Publicly-owned utilities' (POUs) operations and rates are, depending on whether they are municipalities or consumer-owned, overseen by local public agencies or boards made up of their consumers.

Oregon IOUs own most of their electrical system. Thus, all components of their system cost are regulated: generation and distribution by the state PUC and transmission, with some exceptions, by the Federal Energy Regulatory Commission (FERC). This, however, is changing. Deregulation, or restructuring is taking hold across the United States including Oregon. It may be the single most important factor influencing electricity prices. The focus of deregulation has been on generation, including the production and sale of electricity as a commodity, and transmission.

Deregulation was born out of the notion that the marketplace is better able to keep prices low than is government oversight. Many believed that "cost of service" regulation encouraged investments in large generation projects and provided no incentive for utilities to fully evaluate all the risks or all the alternatives to an investment.

There always have been advocates for making the electric utilities more financially accountable in the market for their investments and operations, but little movement was made in the direction of deregulation until the 1990s. It started out at the national level with the passage of the Energy Policy Act (EPACT) of 1992. Among other things, this act made it easier for non-utility generators to build more power plants and enter the wholesale market. This movement expanded in 1996 with FERC Orders #888 and #889 and with Order #2000 in late 1999. These laid the foundation for creating competitive wholesale markets by granting fair access to electric transmission.

Led by California, several states decided that market based generation is in the best interest of the consumers. The California PUC made official in 1995 its commitment to restructuring when it issued an order instructing the utilities to “unbundle” their integrated resources. Retail deregulation in California began on April 1, 1998. The California approach, which is one of the most radical of those implemented so far, forced utilities to sell off their generation resources, transferred operational control of the utilities’ transmission system to an independent entity, allowed the utilities to retain control of their distribution system, and froze retail rates until the end of 2002 (or until their investments in generation facilities is recovered whichever is first).

As of now about half of the states have either started or are in the process of adopting an approach to retail deregulation. The approaches are diverse.

Oregon’s approach to deregulation can be characterized as cautious and gradual. When in place, it will change how utilities serve customers, but it will leave certain retail rates under OPUC regulation, while providing different levels of choice for different customer classes.

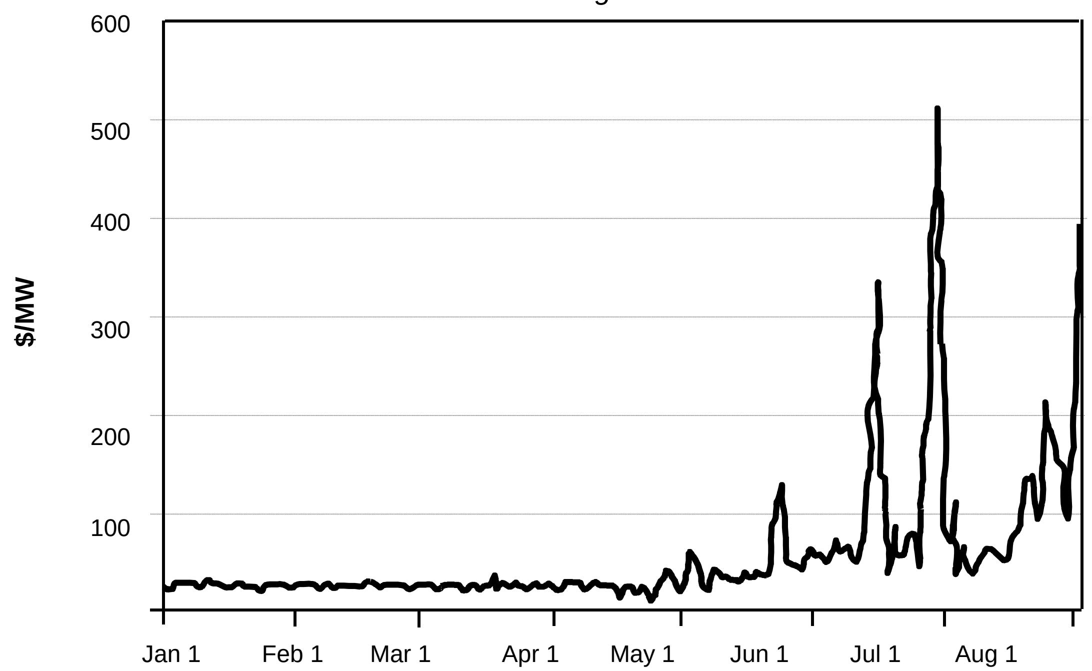
With or without Oregon-specific deregulation, the federal deregulation of the wholesale power market has already had a profound impact on electricity prices and on the way utilities acquire resources. For the most part, utilities are out of the business of building generation resources. Of the 7,800 megawatts in new generation planned in the Pacific Northwest, more than 80 percent is proposed by Independent Power Producers (IPPs). These non-utility companies are in the power business to make money by building power plants and selling their output to utilities or others on contracts of varying length at whatever price the market will bear. As was seen this year, the market will bear a lot when an electrical system is in distress.

c. Causes of Recent Prices Increases

Figure 3 illustrates what happened to electricity prices over this spring and summer. Volatility is a part of any market such as electricity where demand is growing and

Average Electric Price at Western Delivery Points (2000)

Figure 3



Source: Washington State University Cooperative Extension Energy Program

supply is near capacity. Because electric utilities cannot close shop when they run out of their product, they have to shop around for the product wherever they can find it and pay the market price for it. This creates a seller's market. Absent price control, those that have the product will charge whatever the market will allow. Because there is little price response in demand for electricity and very limited storability of the product, prices will spike. This spiking, the ability of prices to climb to satisfy demand, allows more resources to enter the market to meet that demand. The price will continue to spike until alternatives (including curtailment of service to all customers) become preferable. If price controls or "caps" are used to artificially limit the price, producers may not make their product available and shortages will occur.

The events that led to price spikes beginning last spring started in California. Because of the size of that market, and the interconnection of the western grid, the impacts of the California events reverberated throughout the region.

Absent all other factors, energy prices would have been expected to increase because demand is exceeding supply. The state, regional and national economies have been booming leading to high rates of growth in demand for energy. Growing demand devoured the excess capacity in the system. Resources were not being added at the rate that demand was growing for a variety of reasons. The reason most often heard is that power producers did not want to commit major investments while facing uncertainty about deregulation. Given the long lead times to bring new energy resources to the market, the supply systems became severely strained. Prices would have had to increase to reflect the imbalance of supply and demand. Three other factors exacerbated this imbalance this summer.

The first factor was the weather. The Northwest, California and the Desert Southwest experienced periods of higher than normal temperatures this past spring and summer. It started in May, which usually has mild weather, and continued through most of July. According to a study by the Northwest Power Planning Council (NPPC), peak loads were about 3,400 megawatts greater than last year in the Pacific Northwest, while on the same day in California loads were 1,400 megawatts higher. This coupled with an unusual pattern of spring runoff resulting in lower hydroelectric generation, stretched the electric system to the limit.

The second factor was the price of natural gas, which fuels many of the power plants in California. The price almost doubled between summer of 1999 and summer of 2000.

The third factor was that about 2,200 megawatts of generation mostly in Southern California was unavailable during the summer months due to power plant mechanical failure. This plus the growing demand in Arizona added to the squeeze of supplies on which California relies.

However, these factors explain only part of the high price runs that were experienced, peaking at a tenfold increase in June. Even “off-peak” prices in June increased to four times the level of prices in 1999. Electricity generated at times of the day when demand is lower is sold at lower, “off-peak” prices.

The factor that explains the largest portion of the price increases is the environment within which the power systems were operating. The California approach to restructuring forced utilities to divest generating resources and buy energy on the open market. Unseasonably warm weather, the loss of local generating resources due to outages, and other factors led to panic buying.

This in turn created opportunity for power merchants to withhold power from the market waiting for higher prices, aggravating the imbalance and leading to a more volatile situation. The California Energy Commission is investigating whether this occurred.

The market dynamics that caused rising electricity prices in California were not constrained by state borders or by season. When shortages continued into the winter and demand for winter heating grew in the Pacific Northwest, the market exacted a price. On December 11, 2000, U.S. Secretary of Energy Bill Richardson warned electricity generators not to purposefully drive the price for power in the West higher:

> *While I have no specific knowledge of such activities, it is important that generators located throughout the region and in Canada and Mexico understand that the administration will not tolerate any actions designed to take advantage of the situation.*

Wire services reported Washington Governor Gary Locke commenting on December 21, 2000:

> *Once again we are waking up to obscene, manipulative and extortionist electricity prices in Washington, charged by out-of-state power generators…it is pretty obvious there is price manipulation going on.*

Both Washington Governor Locke and Oregon Governor Kitzhaber called on the Federal Energy Regulatory Commission (FERC) to impose region-wide price caps on the price of wholesale electricity for the short term – at least until the situation in California stabilizes.

The interrelationship between the energy resources, the interconnection between states, and an energy supply and delivery system that has little surplus capacity mean that we are entering a period of risk and uncertainty. That risk and uncertainty was given meaning in December 2000.

On December 8, Oregon Governor John Kitzhaber and Washington Governor Gary Locke asked citizens in their states to conserve electricity in anticipation of a severe cold front expected the following week. They took that action because of concern that tight electricity supplies could not meet the demands imposed by the cold weather.

The problem confronted by the Pacific Northwest this winter stems in part from the fact that construction of new electricity generation has not kept pace with the demands of a robust economy. In addition, the Pacific Northwest cannot count on imports from California during the winter because that state's own electricity system is near collapse. In the past, the Pacific Northwest has imported more than 3,000 megawatts from California to meet winter heating demands. California's generating plants ran through the summer in response to electricity shortages and have been down for repairs or because they have met their pollution limits. The regional warning of a potential power shortage was withdrawn the following week as the threat of the cold front diminished and actions to reduce demand were effective. But another threat soon emerged.

On December 13, Secretary Richardson took the unprecedented action of ordering power generators and marketers in the west to ship electricity to California. He did so because he determined that California was experiencing an unexpected shortage of energy because of:

> *…a shortage of currently operational electricity generation facilities, a shortage of water used to generate electricity, unusual volatility of electricity and natural gas markets, and for other reasons…*

The Secretary's statement did not acknowledge a key reason why those power marketers and generators were reluctant to sell power to the California utilities. Those utilities had already incurred billions of dollars in debt to buy high cost electricity. The power marketers and generators were concerned that the utilities no longer had the financial ability to pay for the power they bought.

On December 14, Governor Kitzhaber called upon Secretary Richardson and Jim Hoecker, Chairman of the Federal Energy Regulatory Commission (FERC), to convene an energy summit in the west to deal with the growing crisis. In a letter to Secretary Richardson, Governor Kitzhaber wrote:

> *If no region-wide action is taken soon, the (*energy*) situation threatens to escalate such that the whole West may be short of power throughout a cold and dry winter, and retail utilities may lack the financial resources to purchase needed supplies or to build the generation we all agree is necessary.*

In part, Governor Kitzhaber's concern was based on the knowledge that the Pacific Northwest, already confronting potential shortage, has historically *imported* power from California during the winter heating season.

On December 20, the regional energy summit was held in Denver, Colorado. At the summit were five Western governors, including Oregon Governor John Kitzhaber, and Energy Secretary Richardson, FERC Chairman Hoecker, representatives of electric and gas utilities, electric power producers, and other state and federal officials. The summit focused on building an understanding of regional energy issues and achieving agreement on short-term actions, including aggressive conservation and regional cooperation. The Governors will meet again in late January or early February to discuss longer-term solutions to the energy problems.

Secretary Richardson's order was to end on December 20, but on that day, the Secretary extended the order until December 28, saying that the circumstances that caused him to issue the initial order continued. On December 28, he again extended the order, this time until January 5, saying:

> *I remain concerned that the reliability of the grid in California may be endangered. Electricity generators and marketers continue to express reluctance to sell power in the state given reports about the financial status of California's investor-owned utilities. I believe the order is warranted to keep power flowing to consumers through January 5. It is my sincere hope that further action under my emergency powers will be unnecessary.*

Events in December 2000 highlighted the risk and uncertainty confronting the western states, including Oregon. The actions taken respond to the imminent crisis, but do not resolve the underlying problems that will challenge Oregon for years to come.

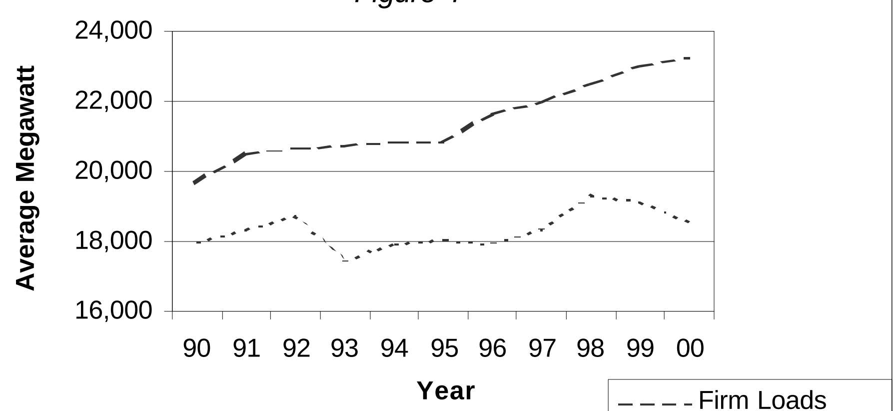
d. Future Outlook

(i) Supplies

Increasing demand in the state and the region during the last decade has eroded any surpluses the electrical system may have had. According to the Pacific Northwest Utilities Conference Committee (PNUCC), during the last 10 years, regional demand increased by as much as 3,500 average megawatts (AMW). During the same period, generation grew by only 550 AMW net of plant closures. Thus, a deficit between regional firm generation resources and firm loads that already existed in 1990 grew even deeper (Figure 4).

Northwest Loads and Generation (1990-2000)

Figure 4



Source: PNUCC, 2000 Northwest Regional Forecast

There are two reasons for the slow increase in generation capacity beside the obvious one that utilities have stopped building power plants to meet demand growth. The first is the reduced hydro generation due to changes in river operation for fish. Even though there were few new projects that added to hydro generation, there was a net decrease of about 750 AMW in hydro generation.

The second reason is the loss of the Trojan nuclear facility, which shut down in 1993. That removed about 800 AMW from the regional generation base.

The deficits shown in Figure 4 will be mitigated somewhat over the next five years in that we will be adding more generation resources. Planned new resource additions total about 2,240 AMW over the next five years. Demand growth for that period is expected to be less vigorous than the last decade. It is expected to be between 383 AMW (BPA forecast) and 873 AMW (PNUCC forecast). However, the deficit remains sizable.

Does this mean the electrical system is in peril? Are we facing imminent shortages? While the electrical system is not in peril, it is in precarious balance. It does not have the capacity it once had to accommodate variations in factors such as weather and adverse stream flows.

While the electrical system is not in peril, it is in precarious balance.

If the ultimate definition of a shortage is that when we turn on a light switch at home and the light does not come on, then shortages are not expected.

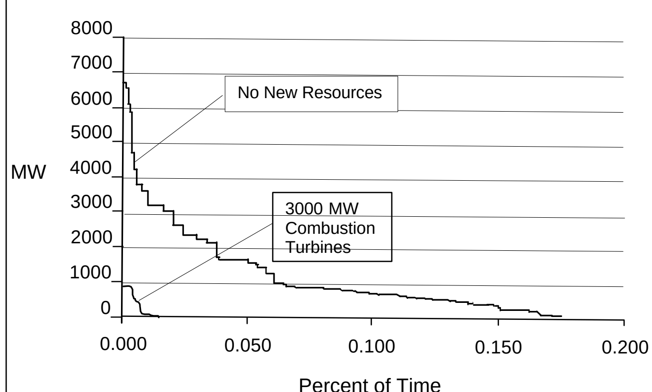
The reason for this incongruent confidence in face of the deficits shown in Figure 4 is that while the chart is an accurate portrayal of "firm" resources, it does not include "all" resources available to the region. Namely, it does not include the additional hydropower generation available from stream flows above the worst stream flows on record. Such surplus averages around 4,000 average megawatts and has been as high as 7,500 megawatts. Also, resources in Figure 4 do not include short-term purchases from outside the region, which can be 3000 to 4000 megawatts. Nor does it include load reductions that are available from retail customers under electricity exchange programs.

In previous times deficits such as shown above would have sent utilities and BPA scurrying to site and construct large power plants to augment firm resources. The environment is much different today. First, given the uncertainties of deregulation, utilities do not know what their future load requirements will be. Customers may choose to buy their power elsewhere. Second, utilities have a different approach to meet their loads. In addition to firm resources, they rely on surplus hydropower, outside purchases, and demand-side measures, such as PGE's exchange program, to meet demands on their system. Therefore, while comparing firm loads and firm resources is a useful tool, it does not tell a complete story about the electrical system and its ability to meet load.

The Northwest Power Planning Council completed a comprehensive study in March 2000 to answer the question of system adequacy. The study simulated the operation of the regional power system under varying conditions of river stream flows and weather conditions. The Council concluded that the region has an increasing probability of power supply problems in coming winters, reaching 24 per cent by 2003. Specifically, the Council study found that over the next few winters, if no generation resources are added beyond what is already under construction, there is a relatively high probability that one or more "generation insufficiency events" will take place. Such events could be of small magnitude and duration - tens of megawatts for few hours. Or they could be quite large - thousands of megawatts for a few days (see Figure 5). These events are typically the result of some combination of adverse hydro stream flows, colder weather, and higher than expected outages of generation facilities.

This 24 percent probability of supply insufficiency is very high when compared to industry reliability standards of one in twenty, or five percent. In order to bring the regional system in line with the one in twenty industry standard, the Council estimates will require the addition of some 3,000 megawatts by 2003 (See Figure 5).

Comparison of Hourly Unserved Load Duration Curve
Without and With New Resources
Figure 5



Source: Northwest Power Planning Council

The Council raised the issue of whether market-driven development of generation resources will be enough to achieve system adequacy. In the past, utilities were willing to develop the necessary resources because they were likely to recover their investment. Now the utility industry operates in a different environment.

Utilities are not developing new resources to meet forecasted loads in their services areas. Independent power producers are undertaking generation resource development. Independent power producers are not regulated and have no obligation to build generation facilities. The only obligation they have is to their shareholders to make a profit. They have no guarantee that they will be able to sell the power they will produce at a profit, if at all. When they make decisions on when and where to build resources, they rely on their assessment of the market and their ability to make a profit. The big question becomes, will the market give them the right signal at the right time? No one has been able to answer that question definitively. If it is truly believed that electricity is a commodity just like other commodities, then the electricity market, if allowed to do so, should be as efficient as other commodity markets in balancing supplies and demand.

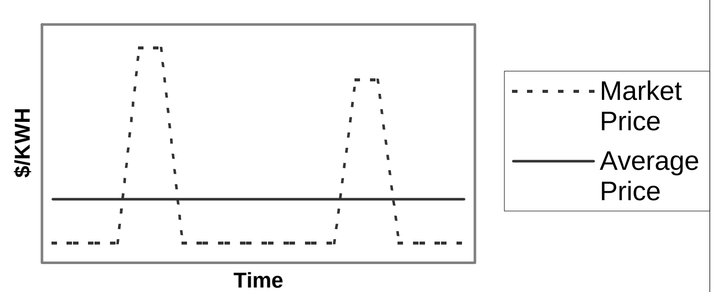
The planning horizon for utilities has shrunk from twenty years to three or four years. This is because utilities do not want to be stuck with long-term power contracts for fear that they may lose their customers under de-regulation and then be stuck with an over-supply they cannot sell.

If this does not yield the needed resources, the market will force adaptation by the utilities, the power producers, and the end users. Utilities could reconsider long-term contracts, power producers could develop resources with shorter lead-time and smaller investments, and end users, to whom reliability is a critical issue, could take matters into their own hands and install local resources. Distributed power generation technologies, i.e. local generation such as fuel cells and microturbines are on the verge of making some of this possible. The use of industrial back-up generators to produce electricity is already being pursued in Oregon.

Market economists contend that there is another critical element to allowing the electricity market to work. That is the deregulation of retail rates. While this may seem a scary proposition in light of the alarming stories from San Diego this past summer, market economists continue to argue retail rate deregulation is an imperative component for the marketplace to do its job.

The extraordinary utility rate increases San Diego consumers experienced were the result of bad deregulation, not deregulation *per se*. For the market to work, market economists argue, the

Average Price Compared to Path of Market Price
Figure 6



ultimate end users have to face the market price for the commodity they are consuming so they can adjust their consumption patterns accordingly. Under cost of service retail rates the consumer only sees the levelized, i.e. average, price (see Figure 6), which market economists contend, distorts the market picture.

Market-pricing proponents point to California's woes to illustrate the problem of having a deregulated wholesale market, but a regulated retail market when a system is resource constrained. Wholesale prices rise sharply, because there is no response from consumers. Since consumer prices are set, they do not experience and do not respond to the price spikes when they occur. Thus, it is argued, some way has to be found for consumers to face the electricity commodity price increases when they occur, thereby inducing customers to use less. One possibility is the use of power cost adjustments taking place when the commodity price reaches a certain level and terminating when prices are back to normal levels.

In conclusion, while deficits loom large on paper, the system will have enough resources to meet demand most of the time. There are combinations of events that may cause shortages of varying magnitude and durations. System operators can devise strategies to deal with most of these situations without curtailment. However, there are situations, although with very low probabilities, that may require some levels of curtailment if enough resources are not built in time.

Although utilities and system operators have obligations to acquire power to meet loads, the question becomes whose responsibility is it to ensure that there will be enough generation to supply that power? Oregonians will increasingly be relying on the marketplace to supply electricity at a cost they can afford.

(ii) Prices

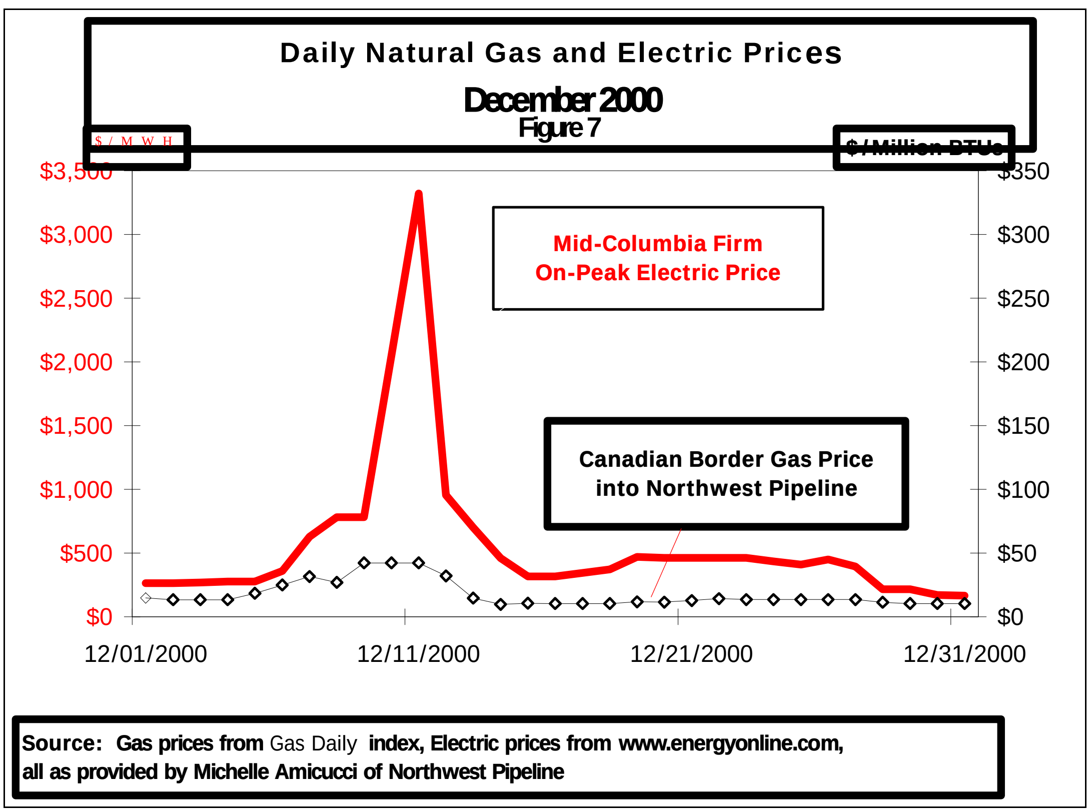
Future electricity prices will largely depend on the portfolio of resources and contracts that our utilities put together to meet anticipated demands. Utilities must deal with and plan for uncertainty in the following:

- Level of demand for power
- What level of hydro generation will materialize
- Weather conditions in their system and surrounding systems
- Cost of fuel and transmission
- Availability and cost of purchased power in various time periods
- Power plant availability
- Transmission constraints

Some of these variables can be forecasted or modeled. Others are virtually unknowable.

Of the three components that make up electricity price, the biggest source of uncertainty, by far, is the generation component. As long as our electrical system is near its limit, generation price volatility will occur. This is expected to continue off and on over the next three years with varying weather conditions, fuel prices, and hydroelectric supply. During these three years, resources will be added. This will help relieve the strain on the regional power system and bring stability back to the system and to prices.

The mid to long-term price trend is expected to be upward. The overwhelming majority of planned generation facilities in the region and the nation over the next 10 years will be fueled by natural gas. Increasing demand for natural gas will increase natural gas prices that in turn will have a significant impact on the price of electricity. The relationship between electricity and natural gas prices was seen in December 2000. Figure 7 shows that when peak electricity prices soared in mid-December with the cold weather, natural gas prices followed, due both to demands from direct use and from electrical generation.



The overwhelming majority of planned generation facilities will be developed by unregulated non-utility entities. These entities recover their cost and return on investment in a much different way than utilities. Utilities recover costs through rates set to recover expenses over time. Independent developers rely on short duration price spikes to recover the bulk of their investment. This is because when power is abundant, the market price is driven by the much lower operational cost of generation facilities rather than the full cost. Thus, this shift in resource ownership will contribute greatly to large price fluctuations.

Oregon's residential ratepayers are somewhat protected from the full impact of market price fluctuations, because retail rates are regulated, utilities own power plants, and utilities have long-term power purchase contracts. This is expected to continue over the foreseeable future as suggested by the cautious approach to deregulation in the state. Under Oregon laws governing deregulation (Senate Bill 1149), nonresidential customers will be able to take more risk in the market. Non-residential customers may choose to buy power that has the potential of lower costs, in return for accepting the risk that the costs may be higher.

The only thing we know for certain about future electricity prices is what is indicated in actions on rates by the OPUC for investor-owned utilities and oversight bodies for publicly-owned utilities.

Portland General Electric (PGE)

In August, PGE proposed a 13.5% overall rate increase based on known and anticipated costs for wholesale electricity and power plant fuel costs. The request was later adjusted upward in November to a 16.5% increase. PGE withdrew this rate increase filing in December 2000 and proposed a plan that could initially keep prices level through most of 2001 by sharing with customers the benefits of selling surplus power on the open market. The proposal is not a formal filing. PGE, the OPUC staff and customer groups will discuss the proposal in more detail in early 2001.

PGE also filed a general rate increase covering all its cost of doing business, not just wholesale power and fuel. PGE's request would make this increase effective on October 1, 2001. Because PGE does not have surplus power for 2002 (the period examined for setting rates), the proposed increase includes the full effect of increases in wholesale market prices. The company projects increase of 24% for residential and small commercial customers and 34% for larger business customers. The Oregon PUC has not taken final action on this proposal.

In addition to these rate increases, customers will pay a three percent "public purpose" surcharge on their electric bills beginning October 1, 2001 under legislation (SB 1149) adopted in Oregon to implement competition. The public purpose charge will provide financing for education service districts, energy conservation, renewable resources development, low-income weatherization, and low-income housing. The utility's current costs for conservation and renewable resources will be removed from rates, offsetting a portion of the 3% public purpose charge.

Pacific Power

Pacific Power recently had two rate changes: 1) an overall increase of 1.79% effective October 1, 2000, and 2) a decrease of 3.97% effective January 1, 2001 reflecting credits from the merger with Scottish Power and the capital gains from the sale of the Centralia power plant, and costs for Y2K activities. These rate changes, however, did not account for recent wholesale power price increases. The company has filed a deferred accounting application for excess power costs from 11-1-00 through 9-30-01. If the application is approved, Pacific Power would be able to track the higher power costs for potential collection from customers at a later date. The company has also filed for a 14.9% increase to take effect October 1, 2001, based largely on the power costs expected after that time. On top of this, there is the "public purpose" three percent surcharge mentioned above starting on October 1, 2001. The utility's current costs for conservation and renewable resources will be removed from rates, offsetting a portion of the 3% public purpose charge.

Bonneville Power Administration

Earlier this past summer BPA filed proposed power rates with FERC for the period October 2001 through October 2006. In November this year, BPA announced that it was amending its rate filing to reflect the cost of power it has to purchase to meet demand placed on its systems. During the previous week, BPA had signed long-term contracts with more than 110 utilities and industrial customers. These contracts exceed the firm generating capability of the federal system. The amendment would result in a minimum15% boost to wholesale power rates. It provides for further rate increases, if BPA's costs increase. Wholesale power cost increases during the 5-year period are likely.

Publicly-Owned and Consumer-Owned Utilities

To the extent they rely on BPA power, these utilities will increase their rates to reflect whatever increase comes out of the BPA rate case. These rate increases will probably start showing up in the spring or summer of next year. How much of the wholesale rate increase will translate into retail rate changes will depend on the utility's other component costs. Generally speaking, a 10% increase in wholesale rate will translate to about five percent retail rate increase. In addition some of these utilities have already undertaken rate increases.

Also, a handful of publicly-owned utilities have some exposure to the wholesale power cost increases of this year. This is because they buy some of their power at market-indexed prices. Depending on the terms of their non-BPA purchases over the last two years, many of these utilities had rate decreases due to market prices lower than BPA's. But, price spikes this year coupled with expiration of some low-cost wholesale contracts are forcing retail rate increase for a few of these utilities. Below is a table showing the recent and pending near-term retail rate increases of these utilities.

Public Utility	***Rate Increase***	***Effective/Proposed Date***
Clatskanie PUD	25%	September 2000
Columbia River PUD	5%	October 2000
Tillamook PUD	9%	November 2000
McMinnville Power & Light	10-20%	Announced October 2000. Anticipated Spring 2001
Umatilla Electric Co-op	9.5%	Proposed for March 2001

In summary, for all utilities that have continuous market exposure, the rate increases seen this year will be at least duplicated next year. If the upcoming winter has prolonged severe weather, Oregonians could be looking at significant rate increases next year.

As resources are added in 2002 and 2003, Oregon's vulnerability to the randomness of weather and hydro variability will decrease. Rates are expected to moderate for several reasons. These include an expected slowdown in the economy, a renewed "conservation ethic" among consumers who have experienced expensive energy and the impacts of curtailment, and expected advances in new technologies such as fuel cells and microturbines. Also, by then deregulation experiments, especially in California, may have matured into market stability.

2. Natural Gas

In natural gas, major customers have had the option of choosing interruptible contracts for many years. Interruptible service is an integral part of the planning of gas utilities to serve the peak needs of customers who are not interruptible.

FERC and Congress began deregulating the natural gas industry in the mid-1980s. The OPUC responded in the late 1980s by changing the way it regulates the local gas distribution companies, NW Natural, Cascade and Avista (formerly WP Natural Gas). By 1990, major customers in Oregon had many service options.

Those customers could physically bypass the local distribution companies and take service directly from the interstate pipelines, avoiding the local utilities altogether. Major customers could use the local gas utility's system for transportation services only and buy their own gas from independent suppliers. These customers may purchase either firm or interruptible transportation services. Finally, these customers may purchase either firm or interruptible service from the local distribution company. Only firm gas purchases include firm distribution and firm interstate transportation.

Demand for natural gas in Oregon is met through the combined operation of three major components of the supply system: production, transportation, and distribution. Production refers to the exploration, drilling and bringing the gas to the surface. Virtually all the production is done outside of the state since Oregon does not have significant gas resources that can be developed economically. Transportation refers to long distance shipment of gas primarily by pipeline from the wellhead to distribution points. Local natural gas utilities receive the gas from the pipeline and deliver it to end users within their service area.

Transportation falls under federal jurisdiction when involving interstate commerce. If the transportation service provider operates wholly within one state, it falls under state jurisdiction. Distribution, usually done through local utilities, falls under the jurisdiction of each state the utility operates in.

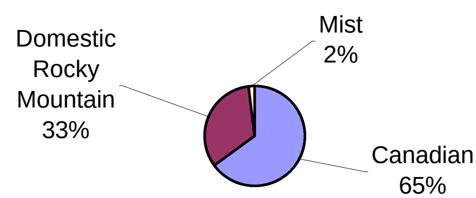
Although natural gas can be stored, consumption by customers occurs by drawing from the system on an as-needed basis. Gas is injected into pipelines every day and is transported to millions of customers around the country. Gas systems traditionally have been designed to meet peak requirements, usually during the heating season. In the summer, domestic gas production and imports are more than enough to meet demand. Some of the excess supplies are placed in storage facilities. In the winter, demand for gas usually exceeds production and import capabilities. The withdrawals from storage facilities are used to provide the extra gas needed to meet customer requirements. Storage is a cost-effective way to meet peak demand.

a. Oregon's Gas Industry

In 1997, 19 percent of Oregon's energy use was natural gas. Oregon's natural gas use grew by about 48 percent from 1990 through 1997.

Most of the natural gas consumed in Oregon comes from Western Canada. Additional supplies come from the Rocky Mountain area. A small amount comes from production fields in Oregon. Figure 8 shows the sources of gas for NW Natural in 1999.

NW Natural
1999 Sources of Natural Gas
Figure 8



Out of state gas flows into Oregon in two major pipelines that serve the western region. The Williams Northwest Pipeline (WNP) brings natural gas produced in the Canadian province of British Columbia from its delivery point at Sumas, Washington. It also brings in gas from Rocky Mountains states. The other major pipeline is Pacific Gas and Electric Gas Transmission Northwest (GTN). It carries gas produced in the Canadian province of Alberta from the border of that province in Northern Idaho down to the Pacific Northwest and into California. The two pipelines intersect near Stanfield, Oregon. The pipeline network is illustrated in Figure 9.

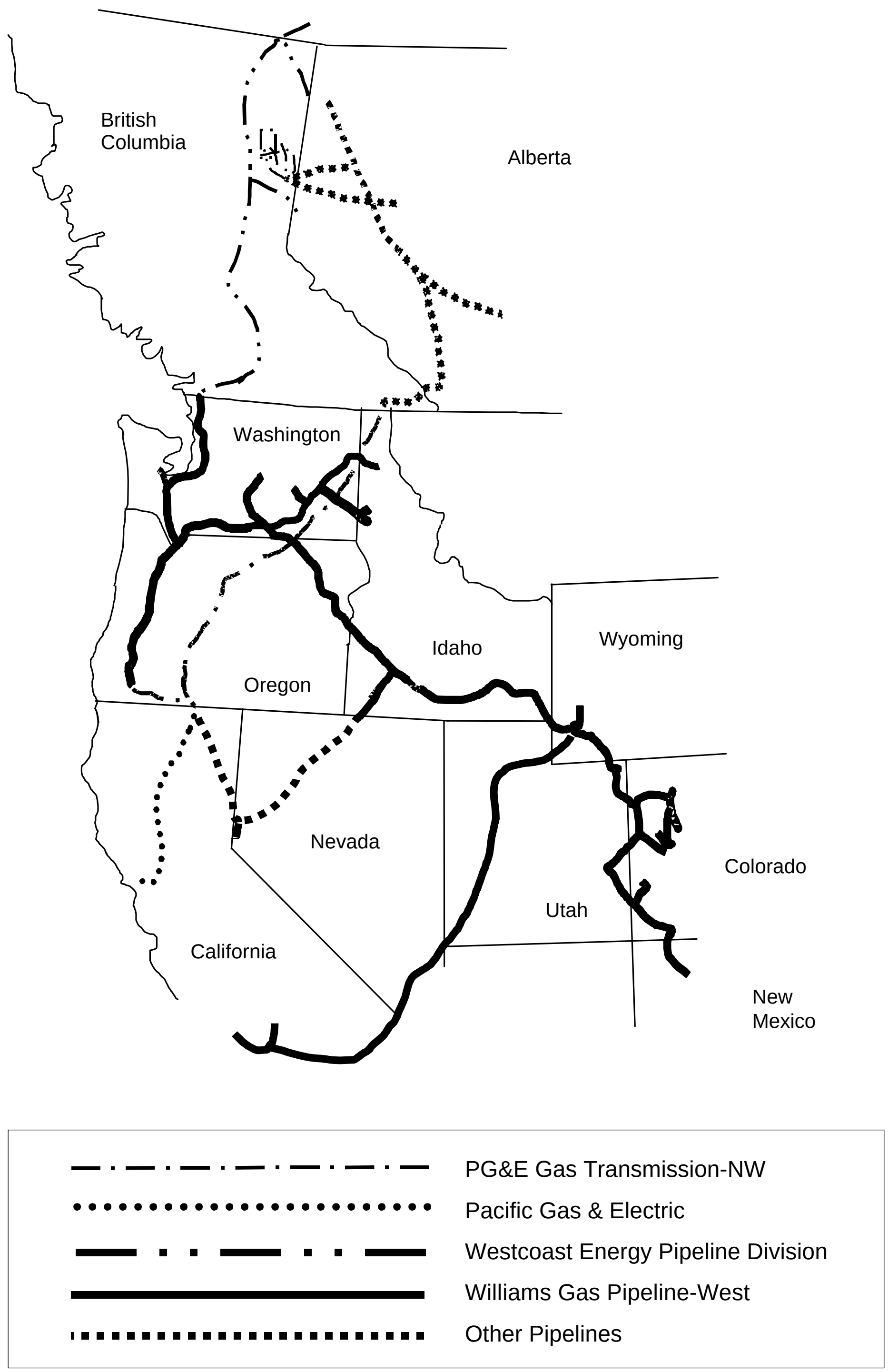
The Willamette valley and southwest Oregon are served by the Williams Northwest Pipeline Company's Grants Pass Lateral pipeline. It connects to the main WNP at Washougal, Washington. The Medford Lateral that connects to the Pacific Gas & Electric GTN pipeline near Klamath Falls, Oregon also serves Southwest Oregon.

Three utilities distribute natural gas to Oregon customers. NW Natural serves Western Oregon and provides 82% of gas sold by utilities in Oregon. Avista Utilities serves portions of Southern and Eastern Oregon is second at 10% of gas sold by utilities in the state. Cascade Natural Gas Corporation serves Central Oregon and accounts for 8% of utility gas sales. In addition to gas sold by utilities, many large industrial users buy their natural gas on the open market as allowed by deregulation that occurred in the mid to late 1980s.

Oregon consumers use natural gas for a variety of needs. Residential and small commercial customers use gas in relatively small amounts primarily for space and water heating. These customers tend to pay the highest unit price but generally enjoy uninterrupted service. Industrial customers use gas in large amounts mainly for process steam and direct heat. Some industrial consumers are served by utilities. Others buy direct from third-party suppliers. Power generators also use natural gas in large amounts for power generation. They are served directly from the pipelines. Although large users usually pay lower unit prices, their purchase contracts tend to be of shorter term and are often interruptible. The interruptibility feature benefits both the gas utility and the customer. The customer gets lower rates and, if it has fuel-switching capability, can shift to lower cost fuels when they become available. The utility can rely on the interruptible portion as a reserve to use when gas is in short supply.

Pipelines Serving Oregon

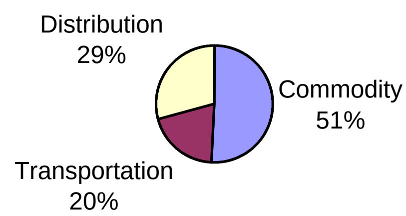
Figure 9



b. Prices

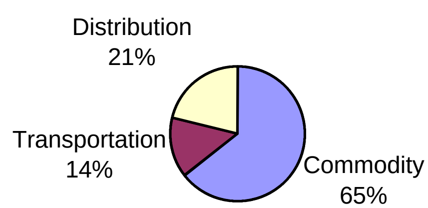
The retail price of natural gas paid by utility customers is made up of three parts reflecting the three components of the gas system: transportation, distribution, and commodity costs. This is depicted in Figure 10a, which shows the price components for general residential rates of Avista Utilities as of December 2000.

Avista Utilities
Residential Natural Gas Rate
Components - As of December 2000
Figure 10a



The distribution component is regulated by the state PUC and prices are based on the cost of service. This includes piping, meters, storage, and administrative costs. The transportation cost, also referred to as transmission cost, is regulated by FERC and is set by contracts. Although the retail rates are regulated, the commodity costs are unregulated and determined by market factors.

Avista Utilities
Residential Natural Gas Rate
Components - With December 2000 Filing
Figure 10b



Because they are regulated, the distribution and transportation costs tend to change moderately over time. The commodity price is not regulated and is determined in the open market by the forces of supply and demand. The significance of this is seen in Figure 10b, which shows the price components for general residential rates of Avista Utilities based on a December 2000 filing to track increased commodity costs. The “gas tracker” would increase commodity component costs to

65 percent of the total rate.

The market has become international in scope. The Canadian and U.S. gas markets have evolved into an integrated North American market. With increasing gas prices, the market may even become international, with liquefied natural gas (LNG) brought by ship from as far away as Asia and Africa.

Among other things, deregulation separated the gas commodity supply and trading from transportation and related services. This is called “unbundling”. Before deregulation, pipeline companies bought gas at the wellhead from producers and entered into contracts with local natural gas utilities to sell and deliver the gas to their distribution center. The unbundling along with the mandatory open access to the pipelines, also brought about by deregulation, revolutionized how gas is traded and priced. Over the last ten years trading has moved from the wellhead to trading centers called “hubs”. Hubs are centers where major interstate and intrastate pipelines interconnect. Hubs allow market participants to buy gas from several sources and ship it to different markets. There are more than 50 of these hubs across the U.S. The largest is the Henry Hub in Louisiana.

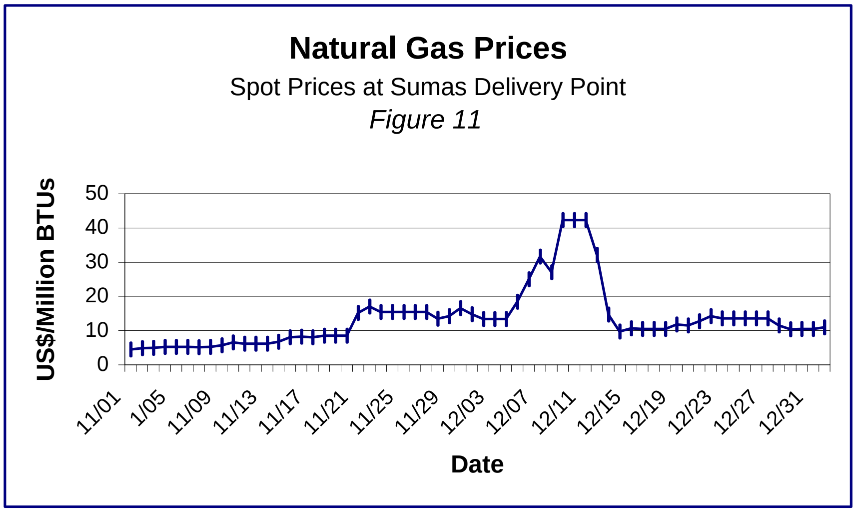
This shift in gas trading has brought two key changes that impact greatly on gas prices and utility planning. First, contract durations have become increasingly shorter and for smaller amounts of gas as buyers seek greater flexibility in balancing load on a daily or seasonal basis. Only about one-third of gas traded is sold on contracts over three years.

The second key change is the emergence of the spot and futures markets. Spot markets deal in transactions of 30 days or less and are at the trading hubs. Futures markets refer to trading where there is a commitment to deliver or take delivery of a specific amount of gas at a point in the future. The trading is done at the New York Mercantile Exchange (NYMEX). The delivery point of gas sold under NYMEX is Henry Hub.

About one-third of the North American market is supplied with gas traded in the spot and futures market. But the impact of these markets on gas pricing goes far beyond the physical size of gas traded in them. The pricing in many sales contracts, including mid- and long-term contracts, is indexed to movements in the spot and future markets. Typically, such contracts have a base price, which escalates according to these movements.

c. Causes of Recent Price Increase

Wholesale spot gas prices have more than tripled from earlier this year at $2 per million BTU to about $6 in mid November. This led to increases of over 20 percent in prices to residential customers in Oregon and across the nation. Since then spot prices have reached as high as $42 per million BTU at the Sumas, Washington delivery point (see Figure 11). At some other western delivery points, prices broke the $50 mark.



Although ominous, this does not necessarily signal shortages. Although supplies of natural gas are tight temporarily, the U.S. has abundant supplies, thanks to a large and diverse resource base. And, Canada, which provides about 13 percent of gas consumed in the U.S., is always eager to satisfy the U.S. market.

But tight markets do yield high prices. A large part of the increase can be explained by the standard natural gas cycle exacerbated by rising oil prices. Demand for gas in the U.S. has been growing for several reasons. First, a robust economy has increased demand for all forms of energy. Second, in markets where gas competes with other fuels, gas is winning. Third, natural gas has become the fuel of choice for new electrical generation throughout the U.S.

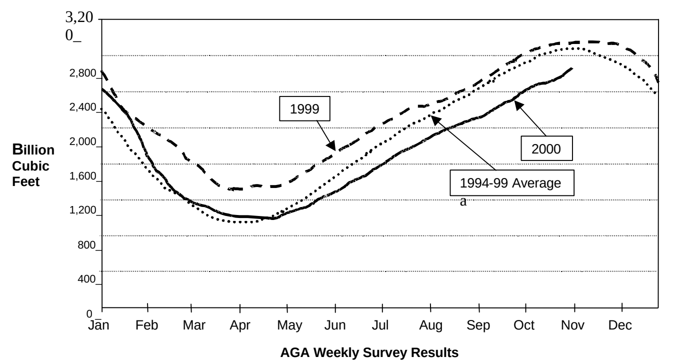
While demand has been increasing at a strong pace, exploration and new production of gas have remained flat over the past few years. This is because natural gas prices have been low for the past few years causing a decline in exploration and drilling for natural gas. This situation is reversing now as more rigs are drilling than at any time during the last 15 years. As the cycle continues, more gas will become available which should relieve pressure on gas prices. However, that will not happen for a while.

Oil prices also had an impact on natural gas prices. Prices for these fuels are usually linked when both markets are supply-constrained. When either market is in surplus, then own-market economics dominate, as has been the case in the last two decades. The dramatic rise in oil prices lifted natural gas prices to a higher level and has helped in maintaining them at that level.

Another pivotal factor that has contributed to maintaining high gas prices is the low level of storage going into the heating season. The only natural gas storage in Oregon is at Mist. As mentioned previously, utilities buy and store gas in the spring and summer when prices are lower and use it during the heating season to supplement gas from production. This year, the price of natural gas started to climb at about the time when gas utilities start buying for storage. Electric generators that use gas for power generation to make up for the hydro generation shortfall in the spring bid up the price. Because previous price spikes have been short lived, many gas utilities delayed their buying for storage hoping the price would go down. It did not. Storage levels never rose to their average levels and were 8 to 10 percent below the average for the last five year (see Figure 12) nationally.

There is one other factor that contributed to the increase in gas prices to Oregon consumers. Oregon's natural gas comes from Canada and the Rocky Mountain area. That natural gas is relatively less expensive than natural gas from the East and the Midwest. The Alliance pipeline began carrying natural gas from western Canada to the Midwest on December 1. More Rockies gas is also going to the Midwest and South. Increased competition for the lower cost natural gas drives prices up in the Pacific Northwest.

Working Gas in U.S. Storage Facilities
Figure 12



The latest round of large price increases in November and December impacting the western states was caused by three factors. First, old gas-fueled power generation was put in operation to cover for several California power plants that were off-line for planned and unplanned outages. The second factor is the colder than normal weather that has persisted over the western states, increasing gas demand for heating. The third factor is the loss of the pipeline from El Paso, Texas to Los Angeles caused by a pipeline explosion in August 2000. In December, that pipeline was still constrained below normal flow levels while it is recovering from the rupture.

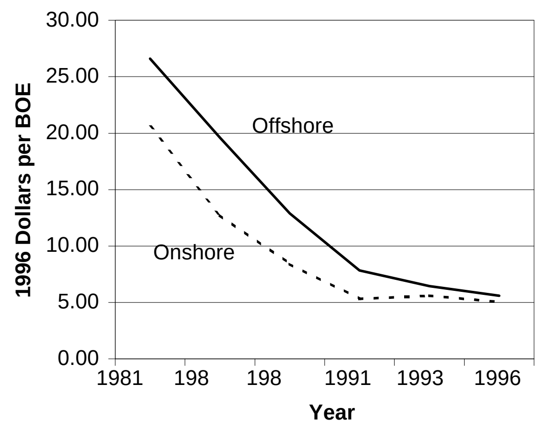
d. Future Outlook

(i) Supplies

The North American continent has a vast natural gas resource base. This resource base includes proven reserves that are ready to be produced and an estimate of the resources that could be developed and produced economically. According to a 2000 analysis of natural gas markets by the California Energy Commission, the U.S. has close to a thousand trillion cubic feet (tcf), including 158 tcf proven reserves. Canada has over 400 tcf that includes 57 tcf of proven reserve. “Proven reserves” are resources ready to be produced. The remainder is an estimate of undiscovered resources that could be developed. The U.S. and Canadian natural gas resources total 1,400 tcf. Combined production in the two countries was around 25 tcf in 1999.

The cost of bringing the gas to the surface has been decreasing significantly. A decade of technological improvements has reduced finding cost, raised the size of the finds, and opened new areas of exploration. Over the past decade, on shore finding costs have been cut in half, and offshore finding costs have fallen even more sharply (Figure 13).

Finding Costs for Natural Gas and Crude Oil
Figure 13



BOE - Barrels of oil equivalent

Source: Energy Information Administration, *Performance Profiles of Major Energy Producers, 1996.*

The resource base as known today is ample to meet the North American market needs for the next 50 years at 1999 production levels. This does not take into account the demands of new natural gas fired electrical generating plants scheduled to be constructed in the coming years. The construction of those plants will be driven by market economics for both natural gas and electricity. For that reason, the pace of construction and the potential impacts on natural gas supply, prices, and transmission requirements is not known.

In addition to this resource base, the industry is developing resources in Alaska’s North Slope and some new Canadian resources. It is estimated that in about ten years these resources could add one tcf a year to production. Alaska’s Governor is also pursuing development of Prudhoe Bay resources, although the potential contribution of these resources is much less significant than North Slope and new Canadian resources.

Additionally, LNG is becoming a viable resource at current prices. There are several countries with LNG facilities that are poised to supply the North

American market.

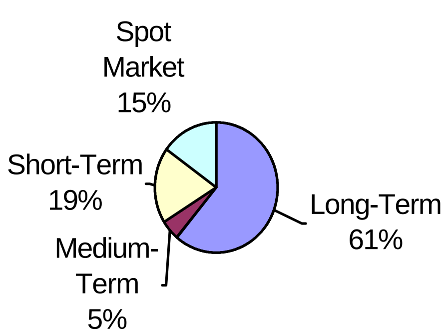
On the horizon are very speculative "unconventional sources" of natural gas such as natural gas hydrates and geopressured brines. These resources are vast, but it will take many years to develop technologies for gas recovery.

It is anticipated that for a long time to come the U.S. will have natural gas supplies that are fairly secure and will be produced in an increasingly deregulated and competitive environment.

Will the infrastructure be there to deliver the gas to markets given the expected large increase in demand for gas for electrical generation? That is probably the most critical question. The infrastructure is quite old. The industry is very capital intensive and a vast expansion of its production, storage, transmission and distribution systems will be needed to meet higher demand. But, the industry has shown willingness to make investment when it believes there are prospects for long-term demand.

On the local level, NW Natural, which provides over 80 percent of the natural gas sold in the state by utilities, is in good position to provide the gas needed by its customers. Over 60 percent of the company's gas supplies is obtained on long-term contracts (Figure 14). However, these contracts are set to expire in 2004. It is anticipated at that time the source of supplies, mainly Canada, will remain the same, but the mix of contract terms will be quite different.

NW Natural Gas Supply Mix
Figure 14



ource: NW Natural

The company expects it will have contracts for the transportation capacity needed to deliver the requirements of its core customers - i.e. customers the utility has a firm obligation to serve. It also is planning on increasing storage capacity to better meet its peak loads.

Even if our local utilities may be in good position to ride the storm of high market prices and short supplies this year and next, there is a real problem looming. When natural gas markets were deregulated it became possible for large users to sever their relationship with their local utilities and buy gas in the open market. Factories, large commercial establishments, and public facilities made the change and did well financially for a while. In today's tight market, it may be time to pay the piper. If their gas is interrupted and they cannot find natural gas except at very high prices, or, even if they can buy natural gas, but no firm capacity to transport it, they face the prospect of either shutting down operation or finding alternative fuels. Fuel oil is the most suitable alternative. If a significant number of these entities flock to an already tight fuel oil market, that will drive the price of fuel oil including home heating fuel oil, significantly higher.

(ii) Prices

Over the past eight months, prices of natural gas in the west have far exceeded what is suggested by fundamental market conditions influencing prices nationwide. As shown earlier, prices at delivery points throughout the West have been at record level, far exceeding other places throughout the United States and Canada. For example, prices at the Sumas, Washington delivery point reached $42 per million BTU on December 9, 2000 while the Henry Hub price in Louisiana was in the $7 to $8 range.

In competitive markets, price fluctuations are expected in response to changes in demand and supply of a given product. These fluctuations become extreme when demand is high and supply is constrained, as is the situation now. The prices experienced in mid-December were not sustainable and came down, but are still far above the levels at which the year started. So, the question is how soon will average prices stabilize and at what level? This will depend on how fast new gas and pipeline capacity can be brought to the market to satisfy increasing demand, the pace of exploration and drilling activity, and the rate of demand growth.

Mark J. Mazur, Acting Administrator of the Energy Information Administration (EIA) reported to Congress on December 12, 2000:

> *EIA expects that high and volatile gas prices will prevail until significantly more gas supplies enter the market, although the likelihood of that in the near future is not high.*

It normally takes several months to a year to bring natural gas supply from the wellhead to the market after drilling occurs. There is a lot of catching up to do. Industry experts believe if current drilling activity, which is very high by historical standards, is maintained, the system should be in balance in about two to three years. For the current drilling activity to be maintained will require a wellhead price of at least $3 to $4 per million BTU.

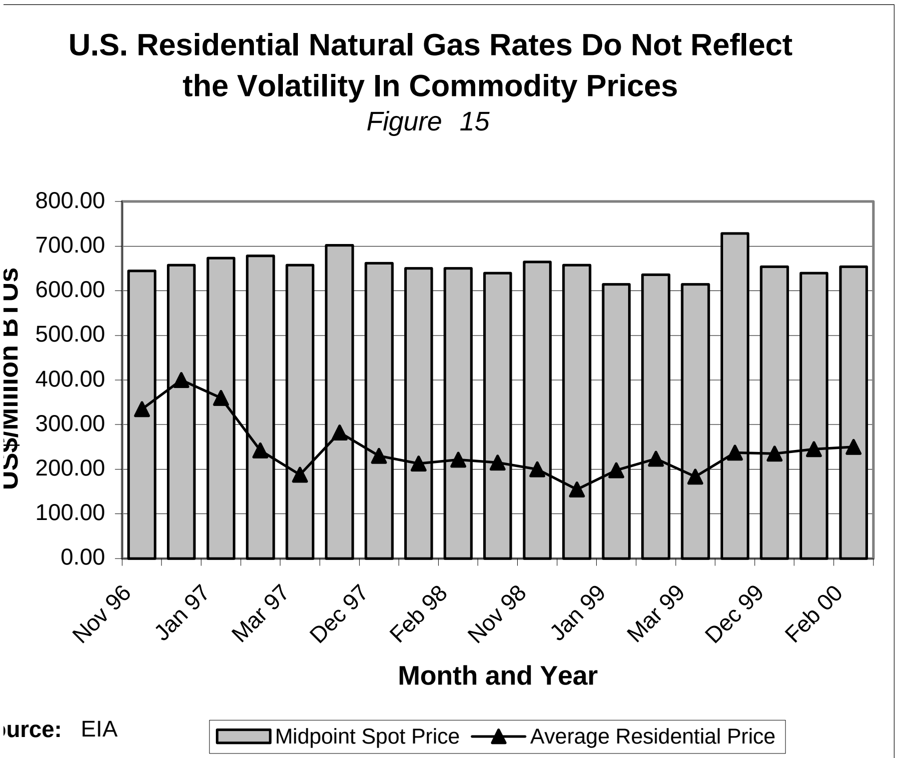
Financial market experts' thinking is in line with that of industry experts with regards to short-term prices. Wall Street consensus predicts composite wellhead prices to average $3.69 per million BTU this year (the range of analyst's predictions is between $3.44 and $3.88). The consensus for 2001 is that wellhead prices will average $3.62 per million BTU with a range between $3.05 and $4.35. Only Lehman Brothers gives a prediction for 2002 at $4.00 per million BTU. However, a Wall Street consensus does not guarantee an outcome.

Most analysts have revised upward their price predictions at least once to account for changes in market dynamics. Most of the concern is with storage levels. Even though we started the heating season with low storage levels, there is still plenty of gas in storage to meet peaking needs. The real problem could come at the end of winter if the storage levels are drawn to very low level and there is another cold snap. This will cause problems in not only meeting peaking need during the cold snap, but will make it difficult to replenish storage the next summer, especially if the economy is still strong and demand for gas for electric generation continues to rise. We could start the next heating season with even thinner storage than this year.

In the long term, it is expected that natural gas prices will be driven by gas use for electric generation. In the Pacific Northwest alone there is a total of more than 6,000 megawatts of proposed gas-fueled generation in various stages of development. Nationally, according to the EIA, a total of 120,645 megawatts of non-utility gas fired generation is scheduled to be constructed between 2000 and 2004. The added demand to fuel these plants will keep upward pressure on gas prices and will spur further development of gas resources. The EIA projects that natural gas prices in real terms, i.e. after accounting for inflation, will begin to decline in 2004. Over the near-term, however, EIA anticipates that wholesale natural gas prices will remain high. The December 12 report to Congress by EIA's acting-administrator stated:

> *In addition to expected supply and demand conditions this winter, continued increases in natural gas demand from new gas generating plants next year will probably prolong the much-above-normal price environment through 2001, even if further gains in U.S. and Canadian production materializes for 2001.*

As discussed earlier, the commodity component of natural gas prices is only part of the total price. Because, as with electricity, retail rates for most natural gas customers are regulated and the natural gas utility does not make a profit on gas purchases, most consumers are insulated from the wild swings in commodity prices (see Figure 15).



This raises the same debate that was discussed earlier under electricity prices about whether consumers should face market price so "correct" decisions are made on gas consumption. Proponents of market economics point to yet another practice by natural gas utilities that obscures the economics of natural gas consumption. "Levelized" billing or budget plans, as they are sometimes called, are designed to equalize monthly payments to avoid unexpected large increases during the heating season. Levelized billing plans are common to electric and natural gas utilities and are required by the OPUC's rules.

Critics claim that these plans while good from a customer service point of view obscure not only the marginal cost of additional gas consumed on any given day, the average cost for the month or season, and the beneficial effects of conservation. While such plans help the customer by blunting the immediate impact of higher winter heating bills, customers do not avoid paying for their gas consumption. Voluntary reduction of natural gas use, if brought about by facing the actual costs, would.

Even though residential customers are insulated from commodity price fluctuations, they do face significant price increases. In September of this year the OPUC granted rate increases to the three gas utilities in Oregon ranging between 21 and 27 percent for residential customers. Commercial and industrial customer rate increases are between 23 and 34 per cent. These increases reflect only the wholesale price increases earlier in the year.

If we experience prolonged extreme weather conditions this year, forcing the drawing down of storage into further deficits, this will have major impacts on retail rates for at least two years. Not only will spot prices be maintained at higher levels, but also storage for next year will either have to be filled with very expensive gas, or the West it will start next year's heating season with severe deficits.

3. Petroleum Products

Once highly regulated, petroleum was deregulated in the 1980s. Since then, petroleum has been subject to price volatility driven by supply and demand in the marketplace.

The petroleum industry supplying products to Oregon is a complex network of facilities around the world. The industry is usually looked at in two major parts: the upstream sector that includes crude oil exploration and production and the downstream sector that includes refining, transportation, and marketing. The industry is highly integrated, with many companies operating in most aspects of both sectors. Large companies, called “majors” own facilities in all aspects of the industry. Smaller companies, referred to as “independents”, are usually not integrated and specialize in one aspect of the industry.

Growing U.S. demand for petroleum products coupled with declining domestic crude oil production have resulted in the United States becoming more dependent on imported oil. From its peak production of 9.6 million barrels per day in 1970, domestic crude production had declined by almost one-third to 6.5 million barrel per day in 1997. For the same period, demand grew by one-fourth from 14.7 to 18.6 million barrels per day.

As a consequence, net imports nearly tripled from 3.2 to 9.2 million barrels between 1970 and 1997 thereby providing about half of our petroleum products in 1997. If everything else stays the same, this increased dependence on foreign sources of oil will be larger because proved reserves of crude oil in the U.S. are declining. As the world reserves are depleted, countries such as Saudi Arabia and other Middle Eastern countries that have a large share of reserves will have a greater role in the world market.

The petroleum industry and its markets are international in scope. The market can be looked upon as two separate, but interdependent markets. One is for crude oil and the other is for refined products. Major companies, independent companies, marketers, and traders operate the market to transfer ownership from producers to consumers. Crude oil ownership is transferred from producers to refiners in the crude oil market. Refined products are sold in the products market changing hands two or three times before they reach the end user. Several types of transactions are used to pass ownership from one part of the industry to another. These include long and short-term contracts, exchanges, spot markets, and futures contracts.

a. Oregon’s Petroleum Industry

Oregon uses more petroleum than any other energy resource. In 1997, petroleum was 47 percent of Oregon’s energy use. Oregon’s petroleum use grew by about 8 percent from 1990 through 1997.

The main products are gasoline, distillate and residual fuels, kerosene, liquid petroleum gases, and jet fuel. Most oil products are used for transportation. The rest is used to manufacture goods and to heat homes and public and private buildings.

Oregon's petroleum industry is but a small part of the international oil market and has little, if any, influence on movement in the market. Oregon has no crude oil resources or oil refineries. Petroleum products are imported in finished form from out of state.

Nearly 90% of the petroleum products used by Oregonians, come from the Puget Sound refineries in Washington through the Olympic Pipeline to the Portland area. An extension of the Olympic Pipeline travels further south to Eugene, bringing gasoline and distillate fuel oil to the Southern point of the Willamette valley. A small amount of Oregon's gasoline and diesel fuel comes from California delivered to Southern Oregon markets by tanker trucks. Another small amount of products comes from the northern Rockies states. An even smaller amount is imported directly from Asia and Canada

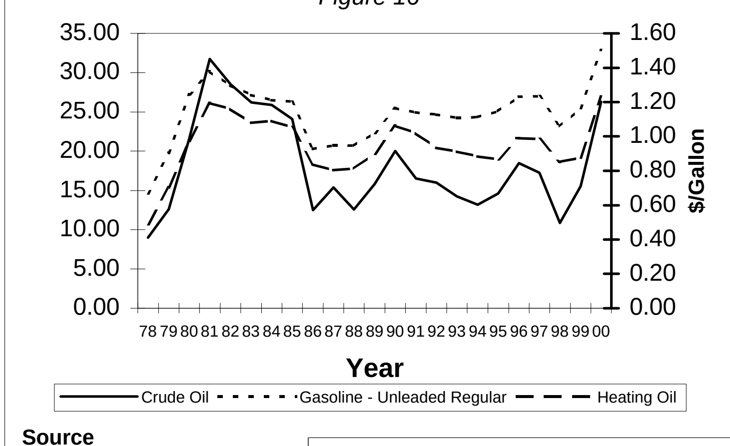
Oregon's petroleum industry encompasses only the marketing component of the industry.

b. Prices

The largest determinant of the price of petroleum products is the price of crude oil. Market demand and OPEC production levels drive crude oil prices. Figure 16 shows how refined products prices track crude oil prices. The crude oil price is set in international markets and is subject to a myriad of political and economic forces.

Petroleum Products Track Crude Oil Prices 1978 - September 2000

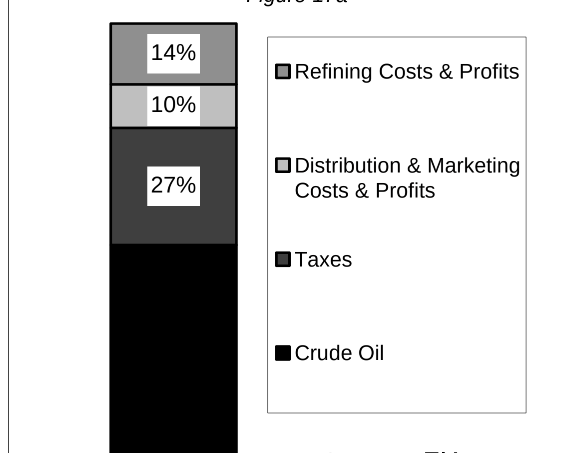
Figure 16



We see time and again how sensitive the market is to events in the Middle East. In 1973 the Arab oil embargo brought the first energy crisis and

Price Components of Gasoline

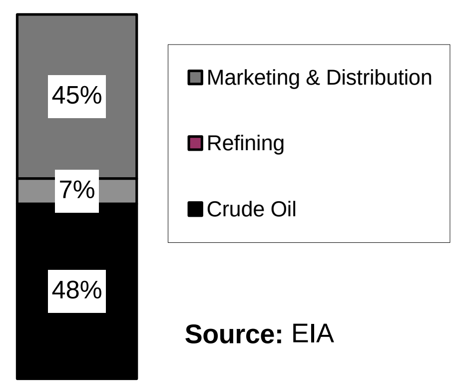
Figure 17a



ended decades of stable prices. The Iranian revolution in 1978 gave the world another major shock. The Iran/Iraq war, which started in 1980, was another event that caused prices to escalate. A decade later, Iraq's invasion of Kuwait brought yet another round of price increases.

Other events that have influenced prices over the years include imposition and later elimination of price controls in the U.S., mandatory and voluntary conservation programs, and changes in the state of world economies.

Price Components of Heating Fuel Oil
Figure 17b



Oil prices are decided in the market, but not oil supplies. The biggest player in the oil market is OPEC. It has influenced world oil prices since its inception in 1960. OPEC has tried to control crude oil prices by controlling the supply - often with some difficulty. When prices are too low OPEC is eager to curtail supplies and when they are too high, it reluctantly agrees to increase supplies. OPEC is most successful when world economy is growing and the demand for oil is growing and approaches production capacity. OPEC has had a mixed record in being able to influence price by manipulating supply, primarily because of lack of discipline among its members. This year they did show a surprising amount of discipline. That is why the high prices were sustained.

While crude oil price is the major ingredient of product prices, refining and distribution contribute significantly. Figures 17a and 17b shows the composition of the price of a gallon of gasoline and a gallon of home heating oil.

c.   Causes of Recent Price Increases

The seeds for the recent price spikes we saw this year have been planted for a number of years. Crude oil prices have been in a general decline since 1981. Prices fell sharply in 1986 as OPEC increased supplies of crude oil. Another sharp decline took place in 1998 in response to the collapse of Asian economies and increased production by Iraq. Prices collapsed to less than $10 per barrel in March 1998.

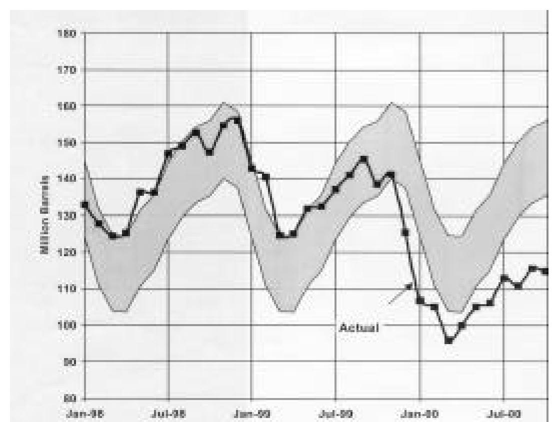
Lower crude oil prices mean lower profits. And, if they last long they lead to slashing expenses and layoffs by oil companies. The industry did curtail some of its exploration and development activity and shut down the higher cost wells. According to the EIA, hundreds of non-major oil and gas producers went out of business after the price collapse in 1986. According to Daniel Yergin, a prominent energy analyst, world oil capacity is 10 percent, or 8 million barrel per day, lower than what was anticipated for 2000 back in 1997. Production capacity additions were not adequate to meet increasing demand when the Asian economy recovered.

Rejuvenated demand in Asia and the rest of the world wiped out the ample supplies of crude oil that were stored during the low price period of 1997-1998. Prices started to increase swiftly in 1999 and as the system approached capacity constraints prices began to spike reaching beyond $30 dollars per barrel.

Another contributing factor to the high prices of refined products is the low level of inventories. Heating oil inventories were critically low entering the heating season (see Figure 18).

U.S. Total Distillate Fuel Stocks

Figure 18



NOTE: The wider, shaded band is the normal stock range.

Source: EIA

Producing more heating fuel as the heating season began led to a reduction of gasoline stocks. This in turn led to the unseasonably flattened price path for gasoline prices this fall instead of the usual downturn.

The low level of storage and unwillingness or inability to increase production in the near term has made the system overly vulnerable to supply disruption. Small disruptions in supply, or the specter of such disruptions, could generate extreme volatility in prices.

d. *Future Outlook*

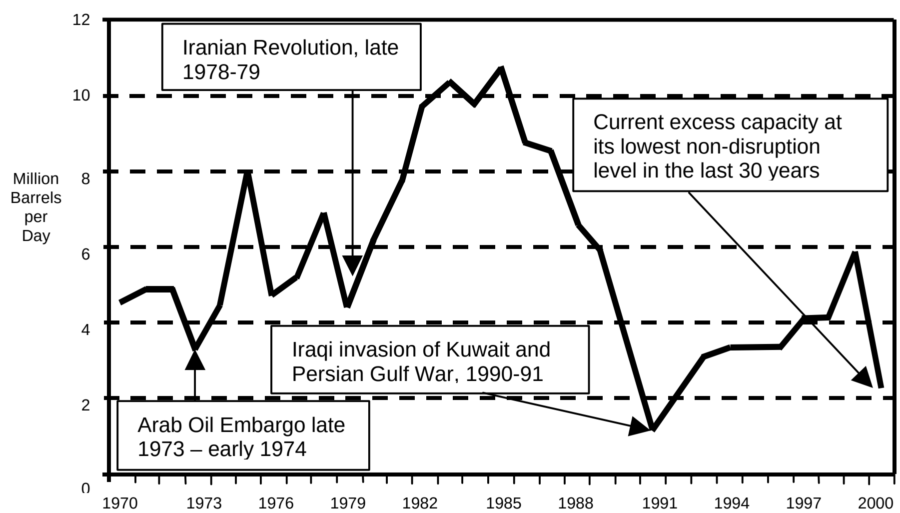
(i) Supply

As U.S. production and reserves of crude oil decline, reliance on imports will increase. That is unlikely to change. That dependence brings with it vulnerability to forces beyond our control. The risks are both of political and physical nature.

On the political side, the current instability of the countries that control the bulk of remaining world crude oil reserves is well known. However, it is unlikely that we will see another oil embargo of the magnitude of 1973. The oil producing countries of today are far more united economically than politically.

The physical risks are more imminent. As discussed above, the major reason for the tripling of crude oil prices this year is that demand has pushed the petroleum industry infrastructure to capacity. Even if it wanted to, OPEC cannot increase production by much because of a deteriorating infrastructure that did not get much attention in the lean years of low oil prices. Updating the infrastructure to a point where it is capable of handling increased production takes time and capital. Figure 19 shows historical world excess capacity levels. It shows that current excess capacity is at its lowest non-

World Excess Oil Production Capacity, 1970 – Present
Figure 19



Source: EIA

disruption level in the last 30 years.

Only Saudi Arabia is thought to have some excess capacity that can be dispatched on short notice. But that capacity has also been eroding since ARAMCO, the only oil producer in the country, was transferred from the ownership of Western companies to Saudi ownership in 1980. For example, at the height of the petroleum crisis resulting from the Iraqi invasion of Kuwait, Saudi Arabia was only able to muster a production level of 8.5 million barrel per day. This is from a system that once was capable of pumping 12 million barrel per day.

A system this tight is vulnerable and is likely to magnify the impact of smaller events. This was seen recently when Israeli-Palestinian relations broke down. The market reacted very nervously for a few days although at no time was there danger of disruption of oil supplies.

Closer to home, the Washington state refineries who are the major source of our refined petroleum products face some potential problems. Those refineries are operating nearly at capacity. While there are restrictions by the state of Washington on capacity expansion, they are expected to produce sufficient amounts of gasoline and distillate fuel oil to satisfy demand in Washington and Oregon. This is according to a report to the Oregon Office of Energy, by Economic Insight Inc, a Portland based economic analysis firm. The report goes on to state that barring a major refinery shutdown, local supply shocks should not be considered a threat. More likely to shock the distribution chain in the Pacific Northwest is a disruption in crude oil supply. The report explains that situation as follows.

The principal source of supply for Puget Sound's refineries is Alaska North Slope (ANS). This oil is shipped from Prudhoe Bay and other oil fields in the Arctic through a 600-mile pipeline. In recent years there has been concern about the safety of the pipeline and its principal shipping terminal at Valdez. The pipeline is over twenty years old and operates in an extreme climate. If the flow of oil through the pipeline or the Valdez terminal were disrupted, the impact on Washington and Oregon would be serious.

Shipping time from Valdez to Puget Sound is ten days or less, while shipping time for alternative oil supplies (from Asia or the U.S. Gulf Coast) exceeds thirty days. Puget Sound's refineries typically hold only a few days of inventory. If the flow of Alaska oil were disrupted there would be an "air bubble" in the logistical system that could cause shortages of gasoline and diesel for up to a month. If such an event were to occur, however, it would also demonstrate the flexibility of the petroleum product distribution system. Petroleum products could be hauled by rail and truck to the West in as little as four to five days. Price spikes, perhaps large in magnitude, would result, but allowing the market to work would ensure the availability of fuel.

Both at the international and the local level, the state of the infrastructure is more to likely to cause disruption of supplies than political events.

(ii) Prices

The two major petroleum products by both magnitude and impact on

Oregonian's daily life are gasoline and distillate fuel oil. The discussion will focus on them.

As discussed earlier, the price of refined petroleum products is mostly determined by the price of crude oil. The OPEC cartel has managed to get control of the oil market and will act to maximize its members' revenue.

This does not necessarily mean that they will attempt to drive the price as high as possible. They have become savvier than that. Learning from past lessons, OPEC members have realized that it is not in their best interest to keep supplies tight and prices high. In the 1980s, high prices led to significant conservation and new non-OPEC oil supplies. OPEC members, Saudi Arabia in particular, have learned that unreasonably high prices are difficult to sustain. They encourage increased production by non-OPEC countries, production beyond agreed levels by OPEC members, and accelerated development of alternate technologies and fuels.

OPEC has tried to fine-tune its control of the world oil market by adopting what it calls a "target range" for its oil. The target range for OPEC average oil price, what is called basket price, is between $22 and $28 per barrel. Prices above the target range, sustained for 20 trading days, would result in automatic increases in production of 500,000 barrels per day. Prices below the target range for 10 trading days would result in automatic cuts in production of 500,000 barrels per day. Although the average OPEC basket price has remained above $28 per barrel since August 14, the price band mechanism has been triggered only once. On October 31, OPEC activated the mechanism to increase aggregate OPEC production quotas by 500,000 barrels per day. However, it was not activated during the last part of November despite the passing of another 20 trading days of high prices that could have triggered the informal mechanism. On December 5, 2000 the price of OPEC oil fell into the target range of $22-28 per barrel for the first time since August 11.

Most analysts predict that crude oil will trade in the $25-35 per barrel range for the balance of this year and next. However, extreme volatility could be experienced if shortages in other fuels, such as natural gas, would drive consumers to the most available substitute—fuel oil. This is a real possibility in Oregon as well as other parts of the country where service to large natural gas user could be interrupted when extreme weather conditions drive residential heating loads upward.

Current prices of distillate fuel (heating oil and diesel fuel) are nearly 50% higher than last year. If the currently depressed level of distillate stocks continues, strong upward pressure on distillate fuel prices will result especially if we get an extended period of cold weather in the Northeast. What happens in the Northeast usually drives the market for heating fuel because it is where 78 percent of the nation's heating fuel is consumed. EIA is predicting that average price for heating oil will maintain at current high levels of around $1.50 per gallon (excluding taxes) through the winter months and then decline to below $1.20 per gallon in summer 2001 and remain there for the balance of the year. Again, we should expect high volatility with extreme spikes with any prolonged cold weather.

In Oregon we have a set of conditions that could drive heating fuel oil much higher. We will have a significant price increase if severe winter temperatures last a long time and force the interruption of service to large natural gas users thereby driving them to compete for dwindling fuel oil supplies with residential consumers. This will not only impact prices this heating season but also at least the next one as storage facilities will be unlikely to refill at the high prices.

Gasoline prices usually decline significantly at the end of the summer driving season. This did not happen this year. For future prices we rely on the forecast developed by the Oregon Department of Transportation (ODOT). ODOT develops a gasoline consumption and price forecast for revenue estimation purposes. The forecast is based on changes the state's economic factors.

ODOT projects that gasoline prices will sustain their current high level but will decline by five percent in 2001 and two percent in 2002 and will maintain at that same level through 2004. Price volatility is likely and events that could lead to such volatility cannot be foreseen by the forecast.

The scenario of service interruption of large natural gas users discussed earlier, could have repercussions for motor gasoline as well. If refineries try to boost their production of heating fuel oil to meet the increased demand for that product, that increase will be at the expense of producing less gasoline. That will lead to lower than normal inventories of gasoline and will drive the cost even higher.

In summary, as long as the petroleum production and refining infrastructure is stretched to full capacity, we will continue to have higher prices. Additional production can only be obtained through committing massive investments, which in turn increase costs, helping to maintain higher prices. Prices are more likely to be volatile when infrastructure is at its capacity. This instability will be exacerbated by any external factors such as extended periods of cold weather. Furthermore, the outlook for expanded refinery capacity is not favorable.

II. What does the Energy Outlook mean for Oregonians?

A. Overview

1. Oregonians at Home

Oregonians will pay higher costs for energy, costs that most have yet to see. In their homes, Oregonians use the most energy for winter heating. The coldest months are December, January, and February. The heating bills for those months will bring unwelcome news of rising energy costs. For Oregonians who heat with oil, the message of rising energy costs was delivered when they first filled their heating oil tanks for the winter. By November of this year, heating oil prices were up 50 percent over last winter.

Oregonians who heat their homes with electricity or natural gas will see their bills grow as rate increases show up in winter heating bills. Even those rate increases do not yet account for all of the additional costs of electricity and natural gas being purchased by utilities in the marketplace. More rate increases are likely in 2001.

For Oregonians most in need, those rising energy costs will be a hardship. That hardship will be tempered by additional funding for low-income energy assistance. The Oregon Department of Housing and Community Services will have $5 million more to help customers of Portland General Electric and Pacific Power. That money will be collected from ratepayers of those utilities as the result of a 1999 Oregon law moving Oregon toward a competitive electricity market. Under that law, publicly-owned utilities will be required to offer a bill assistance program for household that qualify for federal low income energy assistance. Another $3.5 million was added to Low Income Energy Assistance by the federal government in September 2000 in response to rising heating oil prices. This is emergency assistance and cannot be expected in the future. Even with the additional money, the Oregon Department of Housing and Community Services concludes there will not be enough to help all Oregonians who will need help.

For Oregon households, tight energy supplies bring the possibility of curtailments in the event of unusually cold weather or supply disruptions.

2. Oregonians at Work

For Oregon’s businesses, there are difficult times ahead. Oregon’s jobs are produced primarily by small businesses. Most small businesses have firm energy contracts with a high level of assurance that energy will be delivered. For most small businesses, direct energy use represents a small part of the cost of doing business, but even they will struggle with rising energy prices. Those prices are reflected not only in rising utility bills, but also in the costs for goods and services used by those small businesses. For them, rising energy costs and an economic downturn will make survival even more challenging, in a segment of the economy where survival is the exception.

For larger businesses, the market dynamics are more complex. Rising prices, potential supply constraints, and energy purchasing choices made by those businesses may all impose costs. Those conditions combined with a downturn in the economy will affect not only those businesses, but also Oregonians who will lose or already have lost their jobs. Job losses may not be widespread, but that will be little consolation to those who lose their jobs. Any job losses will be particularly hard-felt in rural Oregon.

3. Choices

The only certainty will be uncertainty. Given the interrelationship of energy resources, problems with electricity, natural gas, or oil will affect the other resources. Given the interconnection of supply and distribution systems, problems elsewhere, most notably California, will affect Oregon. Volatility will prevail in the markets for months to come and longer until supply and demand come into balance. Oregon's cautious approach to opening its electricity markets to competition will not change the national and international market dynamics affecting price and supply.

While their choices are few, Oregonians do have choices. They can use less energy in their homes, their cars, and their businesses. They can reduce their peak electricity use. They can pursue new local resources in electricity production and energy infrastructure, but both will impose economic and environmental costs. All these actions will become increasingly valuable in the next few years. All should be pursued.

a. Energy Conservation

The impetus for energy conservation has faded over the last 20 years, as the oil shortages of the 1970's became a distant memory and as investments in new energy resources, including conservation, diminished. Because new energy resources were not being acquired, the costs avoided by conservation were much lower in the 1990s than in the 1980s. Conservation continues, but at a much slower pace.

With the recent increases in wholesale electricity and natural gas costs, Oregonians are not receiving the message about the value of conservation. While petroleum costs follow the market, the rates Oregonians are paying for electricity and natural gas do not reflect the costs of the energy they are using. The market pricing for energy is much more dynamic than the rate-setting process for electricity and natural gas. The energy being used to heat and light our homes and businesses costs more than we are paying, although those are costs Oregonians could well end up paying later. While it could be argued that over the long-term there will not be much affect on conservation investments from the delayed price increases, Oregonians are not seeing the full cost of energy they are using today.

The following comments by electric *(Pacific Power)* and gas *(Avista Corporation*) utilities illustrate the point:

> *Average market prices for electricity in the Pacific Northwest are expected to be higher in 2001 than they were in 2000. Pacific Power expects power prices to be approximately three times as high as what is reflected in its current rates.*
>
> (Because of) *unprecedented natural gas purchase prices in the Northwest markets …you can expect to see some utilities in the region file for early relief of these balances. While unpopular with ratepayers it sends the appropriate price signals to encourage the proper economic decisions about energy usage and conservation.*

Oregonians are not bearing the full brunt of the cost of the energy they are using, because the rising costs of that energy have yet to be reflected in retail rates. As a result, they are just beginning to receive the message about the full value of conservation. This is even truer because Oregonians have not yet received their winter heating bills for the coldest months of the year carrying the rate increases already approved.

Oregon law now requires energy suppliers to offer residential energy conservation services. Energy audits share insights about ways to save energy and money. Cash rebates, low interest loans, and tax credits are available to help finance the cost of energy efficiency measures.

The utility conservation programs are now based on the concept of acquiring energy through conservation in lieu of other energy resources. For that reason, the utility incentives are based on the costs avoided by the utilities in acquiring energy. This affects the incentive levels offered by the utilities and particularly conservation incentives offered by the gas utilities. Unlike the electric utilities that historically have had to make huge capital investments in new generating facilities, gas utilities save only the price of gas coming through the pipelines as the result of conservation. Therefore, the incentives offered by the gas utilities are much more modest than the incentives offered by electric utilities.

Services available from electric utilities are expected to change over the next few years. BPA will offer its customer utilities a new conservation incentive called the Conservation Rate Discount. Those utilities in turn may offer their residential customers added services and incentives. Residential customers of Pacific Power and PGE will begin to see changes in conservation services under the state's electric utility restructuring law. Under that law, conservation programs will be financed through a public purpose charge. A non-profit corporation will administer the programs.

b. Managing Peak Energy Use

The Pacific Northwest's abundant hydroelectric resources have provided not only energy, but also the capacity to meet peak loads and "follow" daily and seasonal changes in electric demand. Peak loads are much higher than the average load requirements. In other regions, more costly generating resources, usually diesel or natural gas fired combustion turbines, have to be brought on-line to meet the peak load requirements. In the Pacific Northwest, more water could be released through the hydroelectric turbines producing enough electricity to meet the peak loads. But additional hydroelectric capacity is now tapped out. While hydroelectricity still will be used to follow loads and meet peaks, the Pacific Northwest must now bring on more costly thermal generation to serve growing loads. Prices at times of peak use will remain high.

In other regions of the country, "time-of-use" and "demand charge" rate structures were designed to pass through the costs of using energy at peak times. Demand charges in the Pacific Northwest are much more modest than in other parts of the country and time of use rates are not widely used. In other regions, both residential and business customers may also use technology to reduce peak use, by not allowing water heaters, air conditioners, or other loads to all operate at once or during specific times of the day. These products shift or "shave" load off of the peaks. The products can be set to times of day, peak customer loads, or signaled remotely by utilities.

Load management tariffs and products are not common in the Pacific Northwest, including Oregon, but represent a potential significant new resource to meet an emerging need.   PGE has had an innovative load management rate that has been very successful, reducing peak loads at a lower cost than serving those loads. Pacific Power recently gained OPUC approval of a similar program. The Eugene Water and Electric Board (EWEB) successfully operated a load shifting and customer generation program to help manage the December 2000 cold snap.

c. Local Resources and Infrastructure

Oregon has no opportunity to develop new gas or petroleum resources and its local electricity resource options are limited and inevitably present conflicts.

Local renewable resources, including hydro, wind, and geothermal, present opportunities for new electrical generation. These opportunities also have economic and environmental costs that will need to be weighed in the deliberative public review process if such resources are proposed.

Significant new natural gas fired electricity generation has been proposed in Oregon and the Pacific Northwest. As of January 1, 2001 approximately 1300 megawatts will be under construction in Oregon. Developers have applied for approval of another 650 megawatts. Developers preparing notices of intent to construct plants have contacted the Office of Energy. These projects would total 2000 to 3000 megawatts that would begin operating in about 2004. If constructed, those generating systems will produce needed electricity, but compete for natural gas used in Oregon homes and businesses. The added demand for natural gas would put pressure on price and supply and require more pipeline capacity.

PGE has been pursuing a "virtual generating plant" that would use back-up generators of industrial customers. Under the virtual resource concept, PGE would buy electricity from these customers during times of peak energy use. This is a use of these generators that was not contemplated in their air quality permits or in Oregon's environmental rules. In Oregon, the Department of Environmental Quality (DEQ) issues the air quality permits. The use of these generators could be considered on either a site-by-site basis, or by considering multiple generators together and permitting them under one permit, or by a combination of these approaches. However, normal permit procedures would have to be followed in either case. Even if the department expedited such permits as much as possible, a minimum of 6 to 8 weeks would be required to issue or revise the necessary permits.

No permit applications have been received to date, making it unlikely that a virtual generating plant could be established this winter. Further, since Oregon's environmental rules currently do not address the use of back-up generators as peaking generators, there are no rules that specify the emission control and nuisance abatement requirements that would have to be met. Owners of potentially usable back-up generators are perhaps reluctant to apply for permits without clear knowledge of what requirements they would have to meet if they were to operate them as peaking generators. DEQ plans to work on rules to address the use of back up generators as a virtual generating resource with the goal of having rules in place before the winter of 2001. With regard to this winter, DEQ is continuing to work with PGE to develop the concept, but wishes to avoid emergency rulemaking unless and until a true emergency situation develops.

In addition to local electricity resources, there is also a need to build infrastructure. The construction of transmission and distribution systems has not kept pace with growing energy demands.

There is a need for more gas pipeline capacity by local gas utilities and for deliveries from interstate pipelines to serve independent power producers. While the local gas utilities are dependent on regulatory approval of financing to build infrastructure, the interstate system is dependent on market conditions and whether large Oregon customers and independent power producers will commit to firm deliveries, which they have not.

In summary, Oregonians have the opportunity to use energy more efficiently in their homes, businesses, and industries, but those actions take time and cost money. Not only businesses, but also public institutions engaged in the already open market for natural gas purchases are only now beginning to understand the risks associated with those decisions and have more to learn about managing those risks.

Oregon can pursue local resource options for electricity, such as use of industrial back-up generators to meet peak loads, but those actions will have air quality impacts that the regulatory process has not begun to consider.

The development of new resources and transmission and distribution systems is essential to meet growing demand and improve reliability, but such actions are inhibited by market and regulatory uncertainty whether as the result of restructuring of the electricity markets or uncertain environmental regulation. Innovative rate designs to encourage load management to reduce peak demands are also possible and have been implemented by at least three Oregon utilities, but the Pacific Northwest has much to learn about load management, which has not been an issue in years gone by.

Oregon cannot resolve the national and international market uncertainties, but it can choose to take actions to manage risk.

B. Oregonians at Home

Oregonians will pay more for energy, whether they heat with electricity, natural gas, or heating oil. For low-income Oregonians, those rising energy costs will be a hardship.

Energy supply constraints are least likely to affect Oregonians at home. Residential energy use is considered a "firm" load and utilities will do all they can to make sure those needs are met. Heating oil customers could confront pressures on prices and supplies, but while higher prices may occur, severe supply shortages are not foreseen. A combination of severe cold weather and plant outages or other problems in the supply and delivery systems could impose supply constraints, but loss of service is unlikely.

There will be rising energy prices. Those prices will compete for a larger share of income, but for low-income Oregonians the price increases will be a hardship. The following discussion explores the resources available to help Oregonians most in need.

1. Low-Income Energy Assistance

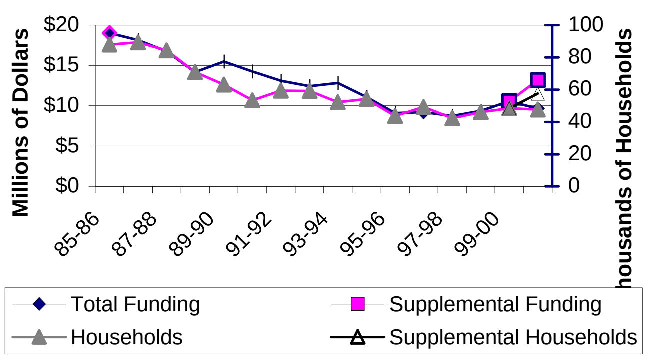
Low-income energy assistance is offered through grants for home weatherization and bill payment assistance. Financing for those programs comes through diverse federal, state, local, and utility resources. The basic statewide low-income assistance programs however are offered through the Oregon Housing and Community Services Department.

a.   Oregon Housing and Community Services Department

The foundation for Oregon's low-income energy assistance is the programs administered by the Oregon Housing and Community Services Department (HCS). Most of the money available to help low-income Oregonians with their home energy costs comes from the federal government through this state agency.

The U.S. Department of Health & Human Services (HHS), the U.S. Department of Energy, and BPA provide funding for the low-income energy programs, and funds are contributed by utilities. This funding supports both low-income fuel assistance and weatherization. The Oregon Office of Energy's State Home Oil Weatherization (SHOW) Program offers grants through local community action agencies for weatherization in low-income homes heated by oil, propane, butane, kerosene, or wood. There is no state financing for fuel assistance, other than emergency assistance offered by the Department Human Services, Adult and Family Services Division.

Oregon Housing and Community Services Department
LIEAP FUEL ASSISTANCE
Figure 20



Most of the low-income fuel assistance funding comes from the U.S. Department of Health & Human Services' Low Income Energy Assistance Program (LIEAP). That money provides grants for low-income Oregonians whose income is at or below 60% of the median statewide income. For example, a family of four earning $27,060 a year or less would be eligible. For perspective, the Oregon Office of Energy estimates that about 250,000 Oregon households have incomes below the federal poverty guidelines. These guidelines are much lower than the income standards used for LIEAP. Many more Oregon households would qualify for LIEAP.

The funding for LIEAP has declined over the years. Oregon received just over $19 million in 1985-86 serving 87,994 households. In 1999-00, Oregon's funding is $10.5 million serving an estimated 48,413 households, 55% of the households served in 1985-86.

In response to the rising fuel oil prices, President Clinton released an additional $400 million nationwide for low-income fuel assistance in September 2000. Oregon's share was $3.5 million.

Oregon has committed the supplemental funding to meet rising heating oil and propane costs among low-income Oregonians. A crisis payment of up to $250 is being added to the average payment of $200 to offset increased heating costs. HCS anticipates that the supplemental funding will serve about 10,000 low-income households.

In addition to the supplemental federal funding, significant new financing has been derived from a law adopted by the 1999 Oregon Legislature. This law (Senate Bill 1149) establishes the framework for Oregon's move toward a competitive market for electricity. Under this law, PGE and Pacific Power began collecting $5 million per year on January 1, 2000 for low-income bill payment assistance. Under this law, publicly-owned utilities will be required to offer a bill assistance program for household that qualify for federal low income energy assistance. Monthly collections are distributed through HCS to local community action agencies for low-income customers served by PGE and Pacific Power. The contribution will increase to $10 million for low-income fuel assistance and funding will also be collected for low-income weatherization after competitive markets begin October 1, 2001. Legislation is needed to clarify the intent that the $10 million contribution is to be collected annually.

Even with the additional funding for low-income fuel assistance, HCS acknowledges that this winter as in winters past, there will not be enough money to serve all low-income households in need.

The HCS financing is complemented by support from Oregon's utilities and heating oil dealers, but additional state emergency assistance financing is also offered through the Oregon Department of Human Services.

b. Department of Human Services

The Adult and Family Services Division, Oregon Department of Human Services (DHS), manages two programs that provide payments to low-income households. Those programs are Temporary Assistance for Needy Families and Emergency Assistance. These programs help low-income families pay for basic necessities including food, clothes, utilities, transportation, rent, and energy.

(i) Temporary Assistance for Needy Families

The *Temporary Assistance for Needy Families* program serves approximately 15,500 families (households) per month. The program is funded at approximately $127.7 million each biennium. The maximum monthly payment per household is $458.00. Payments are made directly to families or through community assistance programs throughout the state. The monthly assistance checks are not targeted for any specific use. In some cases the payments may go for food, in other cases rent, clothing, transportation, or some combination. However, if energy costs significantly increase, some families may spend more of their monthly payment on higher energy bills particularly during the winter months.

(ii) Emergency Assistance Program

The *Emergency Assistance Program* provides low-income families a one-time payment per year in emergency assistance for payment of rent, transportation, utility bills, food, clothes, and related necessities. The program is designed as an interim step to reduce the number of households applying for the *Temporary Assistance to Needy Families* program. The program currently serves approximately 1,600 different households each month. Payments average $350 per family. Assistance payments are not directed toward any specific use. Each household determines how the payments will be used and the payment may be used to meet rising energy costs. The program is funded at approximately $12.5 million for the1999-01 biennium.

There is no additional funding available to address rising energy costs this winter.

c. Community Programs

There are diverse programs in local communities to help Oregonians in need. While all of those local initiatives have value, it is useful to describe two programs that help low-income, senior, and disabled Oregonians stay warm in the winter. These two programs are used as community resources by utilities and heating oil dealers.

(i) Oregon HEAT

Oregon HEAT (Home Energy Assistance Team) is a non-profit organization that uses donations to help low-income families throughout Oregon pay their heating bills in an emergency. Oregon HEAT generally serves single-parent families with small children and older Oregonians on a fixed income. Last heating season, Oregon HEAT raised about $750,000 to help more than 5,000 households pay their bills.

(ii) Community Energy Project

Community Energy Project (CEP) is a non-profit organization in Portland providing weatherization assistance to senior and disabled Oregonians and community energy education. Since 1987, CEP has installed energy saving measures in more than 1,900 homes free of charge. CEP also conducts 45 self-help workshops annually teaching 540 homeowners and renters how to stay warm and lower their heating bills. Participants in the workshops receive a free kit of materials including do-it-yourself weatherization products and detailed information on wise energy use.

d. Investor-Owned Electric Utilities

PGE, Pacific Power, and Idaho Power are the investor-owned electric utilities serving Oregon. Idaho Power's service area is in Eastern Oregon. Pacific Power's service area is dispersed to communities throughout the state from North Portland to Lincoln City to Medford to Pendleton. PGE's service area is in the greater Portland Metropolitan and Salem areas.

As part of the restructuring of Oregon's electric utilities for a competitive market, the 1999 Oregon Legislature adopted Senate Bill 1149. That legislation dedicates a 3% surcharge to finance specific public purposes. The 3% surcharge is expected to result in collections of about $50 million a year for ten years. The surcharge applies only to PGE and Pacific Power at the moment, but any utility opting to participate in the competitive market under SB 1149 would contribute. Among those public purposes is low-income weatherization:

SB 1149 Public Purpose Funding

3% Surcharge Allocation

Education Service Districts	10%
Cost-Effective Conservation and New Market Transformation	57%
Above-Market Costs of Renewable Resources	17%
Low-Income Weatherization	12%
Low-Income Housing Trust Funds	4%

PGE and Pacific Power began collecting $5 million per year on January 1, 2000 for low-income bill payment assistance. Monthly collections are given to the Oregon Housing and Community Services Department for distribution to local community action agencies, which give the money to low-income families in communities served by PGE and Pacific Power. This $5 million is called "SB 1149 Bridge Financing" covering the time until competitive service begins October 1, 2001. After October 1, 2001, the amount is expected to increase to $10 million. SB 1149 did not make clear the intent that the $10 million be collected annually, but it is anticipated that legislation will be considered in 2001 to resolve this ambiguity.

(i) Portland General Electric (PGE)

PGE makes corporate contributions to Oregon HEAT to match customer donations for low-income fuel assistance. PGE plans to donate an additional $57,000 in corporate contributions next year for a total of $100,000 and donates another $75,000 in in-kind contributions to support Oregon HEAT. The combined value of PGE donations to Oregon HEAT in 2001 then could reach $175,000.

PGE currently contributes $200,000 a year in ratepayer financing for low-income weatherization. This financial support covers up to half of the home weatherization costs for low-income families. PGE will make a new corporate donation of $200,000 in 2000 and 2001 to cover the other half of the cost of home weatherization. The corporate contribution is part of the Sierra Pacific Resources agreement to acquire PGE. The money goes directly to community action agencies to serve low-income households in PGE's service area. This funding will most likely not continue after October 1, 2001 when the competitive market is scheduled to begin under SB 1149.

PGE also supports the Community Energy Project (CEP). Each year 50 - 100 PGE employees perform volunteer services and PGE has donated more than $32,000 in recent years to CEP.

(ii) Pacific Power

Pacific Power is spending $400,000 per year for three years on new programs to assist low income Oregonians. The majority of the money goes to the Oregon Housing and Community Services Department's REACH (Residential Energy Assistance Challenge) Program, which provides debt counseling and energy education services. A smaller portion of the money goes to the Community Energy Project.

In November and February, Pacific Power solicits donations to Oregon HEAT through bill inserts. Pacific Power matches, dollar for dollar, the donations their customers make. The program raises tens of thousands of dollars for Oregon HEAT.

Pacific Power has a program for low-income weatherization, for which $500,000 was budgeted this year. Pacific Power's goal is to cover 50 percent of the costs of local agency weatherization projects for electric-heated homes in its service area. Local agencies receive grants from additional sources (mostly federal funding) to make up the balance, making the projects free to low income customers.

e. *Publicly-owned and Consumer Owned Electric Utilities*

The low-income fuel assistance programs of Oregon’s 36 publicly-owned utilities are diverse. The programs include customer check-off donations on their monthly bills, utility-funded assistance, and reliance on the federally funded fuel assistance programs of the local community action agencies. Some utilities, including EWEB, Emerald PUD, and City of Ashland, also make contributions to Oregon HEAT. The utilities also work closely with customers through payment options, such as equal pay programs, to help them manage winter heating bills.

Again, under SB 1149, publicly-owned utilities will be required to offer a bill assistance program for household that qualify for federal low income energy assistance.

f. *Gas Utilities*

Oregon’s gas utilities also provide financial support for low-income Oregonians.

(i) *Avista Corporation*

Avista's corporate fund for low-income fuel assistance is called Project Share. Most contributions into this fund come from employees and customers. In recent months the contributions levels have been over $3,000 per month for Avista’s Oregon segment of this fund. Avista’s corporate contribution to the fund for Oregon customers was $8,000 in 2000.

(ii) *NW Natural*

NW Natural has a low-income bill assistance program called the Gas Assistance Program (GAP). Contributions are solicited from employees, customers, and shareholders. The program has been in place for 17 years collecting nearly $180,000 in 1999, which has been distributed to more than 1,700 households. GAP funds are collected and distributed by United Way.

Understanding that the recent upswing in prices may make bill payment difficult for low-income customers, NW Natural has increased its contribution from $35,000 (last year) to $75,000. The maximum amount to be distributed has been increased from $125 to $150.

NW Natural works one-on-one with customers who have bill payment problems and expects to continue that practice. It also communicates the advantages of equal payment plans for assistance in budgeting for winter bills and many more customers are signing up for this service.

NW Natural supports a number of community-based events each year. Three "Fix-It-Fairs" are organized each year by the City of Portland and the utilities where free-weatherization, do-it-yourself weatherization and water conservation kits are featured. In October, when the heating season begins, NW Natural partners with the Oregon Office of Energy, the City of Portland, major retailers, PGE, and Pacific Power to sponsor an "Energy Awareness" campaign. This program results in eight million media impressions that promote the efficient use of energy within the common service areas of the utilities.

NW Natural has donated energy efficient gas space and water heaters for installation in Habitat for Humanity homes.

g. Heating Oil Dealers

Because Oregon's heating oil industry comprises nearly 200 small businesses; there is no comprehensive statewide program for low-income fuel assistance. The Oregon Petroleum Marketer's Association (OPMA) is working in concert with Oregon HEAT to raise donations for fuel assistance. Heating oil dealers statewide have been asked to include donation envelopes in the customer billings.

Heating oil customers also have a choice within this competitive market of selecting heating oil service based on lowest cost or payment options comparable to the equal pay programs of the utilities.

Within their local communities, individual heating oil dealers participate in diverse community services, including delivering oil pumped from abandoned tanks and donations for needy families.

2. Choices at Home

Oregonians do have a choice. They can use less energy in their homes. There are services and financial assistance to help them do that.

Oregon law now requires energy suppliers to offer residential energy conservations services. Energy audits share insights about ways to save energy and money. Cash rebates, low interest loans, and tax credits are available to help finance the cost of energy efficiency measures.

a. Utility Conservation Programs

The conservation services and incentives offered vary from one utility to another. Utilities like Salem Electric view energy conservation not just as a way to acquire energy resources, but as a valued customer service. Their energy conservation services are comprehensive, timely, and responsive and they offer attractive financial incentives. Other utilities place less emphasis on energy conservation and have long lead times for energy audits and modest financial incentives. In any case, the utility conservation programs are a resource for Oregonians to learn about ways to save money and energy at home.

Services available from electric utilities are expected to change over the next few years. BPA will offer its customer utilities a new conservation incentive called the Conservation Rate Discount. Those utilities in turn may offer their residential customers added services and incentives. Residential customers of Pacific Power and PGE will begin to see changes in conservation services under the state's electric utility restructuring law. Under that law, conservation programs will be financed through a public purpose charge. A non-profit corporation will administer the programs.

b. State Services and Financial Incentives

The State of Oregon offers services and financial incentives to help Oregonians use energy more efficiently in their homes.

(i) Office of Energy

The Oregon Office of Energy offers financial incentives to help Oregonians make their homes more energy efficient, comfortable, and affordable.

(a.) State Home Oil Weatherization (SHOW) Program

For households heated with oil, propane, butane, kerosene or wood, the SHOW program offers rebates for weatherization and heating measures. The rebates are targeted to low-to-moderate income households. Homeowners can qualify for low-interest loans to pay for recommended measures. The program also provides free home energy audits. Oil companies doing business in Oregon fund the program.

(b.) Residential Energy Tax Credit Program

The residential energy tax credit program helps Oregon households invest in renewable resource systems and energy-saving technologies for the home. The tax credit is offered for solar, wind or geothermal space or water heating systems, premium efficient appliances, alternative-fuel vehicles and charging systems (including hybrid cars), photovoltaic systems and fuel cells. Any Oregon homeowner or renter can qualify for the credit with purchase of an eligible system.

(c.) Business Energy Tax Credit Program

Single family and multi-family rental housing is a business and qualifies for the Oregon Office of Energy's Business Energy Tax Credit Program. These tax credits are offered to businesses to encourage them to invest in energy conservation, renewable resources, recycling and alternative fuels. The tax credit is 35 percent of the cost of the investment, taken over five years. Conservation measures in rentals and multi-family housing must generally pay back the cost of the investment in more than one and less than thirty years. Examples of projects include weatherizing apartment buildings, installing new energy efficient heating systems, and installing energy-efficient lighting.

(d.) Northwest Energy-Efficient Manufactured Homes

The Office of Energy has worked with the manufactured home industry since 1988 to build energy-efficient homes. Under a voluntary agreement with Oregon manufacturers the Office certifies homes that are very efficient. Electrically heated homes meeting these standards are called "Super Good Cents" and gas heated homes are called "Natural Choice". Compared to homes built to federal standards, these homes have more insulation, more efficient windows and doors, better-sealed ducts and whole-house ventilation systems. On average, Super Good Cents and Natural Choice homes reduce the energy needed for heat by almost half.

(ii) Housing and Community Services

Housing and Community Services administers statewide programs through local community action agencies or other lead agencies to weatherize the homes of Oregonians most in need. Most of the money comes from federal funding, but there is also funding from BPA on behalf of publicly-owned utilities and investor-owned utilities. The Oregon Office of Energy provides funding directly to local community action agencies for low-income weatherization services.

A major source of funding for low-income weatherization comes from the U.S. Department of Health & Human Services (HHS) Low-Income Energy Assistance Program. In 2000-01, an estimated $1.9 million will be available to weatherize about 890 homes. Another $1.3 million will be transferred from low-income energy assistance to weatherize about 590 homes. HCS can transfer up to 15% of the fuel assistance money into weatherization. That is done because weatherization is a longer-term solution than bill payment assistance.

Another major source of funding for low-income weatherization comes from the U.S. Department of Energy's Weatherization Assistance Program. That funding has been greatly reduced over the past decade. In 2000-01, funding of just under $1.7 million will serve an estimated 636 households. In 1992-93, funding of just under $2.5 million served about 1,310 households.

BPA will provide about $900,000 in 2000-01 to weatherize an estimated 450 Oregon homes.

In addition, the Oregon Office of Energy provides financing through the State Home Oil Weatherization (SHOW) Program for energy conservation for low-income households. This money comes from Oregon's heating oil industry and is used by local community action agencies to weatherize low-income homes.

Oregon's investor-owned utilities contribute significant financial support to low-income weatherization programs. The investor-owned electric utilities will collect public purpose funds dedicated to low-income weatherization under SB 1149. NW Natural also contributes to low-income weatherization as mandated by the Oregon Public Utility Commission.

C. Oregonians at Work

1. Adverse Impacts

The changing energy markets may have significant adverse impacts on Oregon's businesses. Those impacts may result from price, supply and purchasing decisions.

a. Price

Rising energy prices will have an impact on Oregon businesses. Those prices will be reflected in product costs and in turn in competitive position. While the Pacific Northwest is not necessarily at a disadvantage when energy costs are compared with the rest of the nation, the impact could be significant nonetheless for at least five reasons.

First, for many industries, competition is not just national it is global. While the cost increases in petroleum have been international, recent electricity and natural gas price spikes have been driven by conditions unique to the United States. The uncertainty inherent in those price spikes will be a consideration in significant plant investment in the United States.

Second, Oregon has used its relatively low electricity costs to its competitive advantage. That advantage is narrowing, and unlikely to be a strong selling point in the not too distant future. With new electrical generation being supplied by natural gas and increasing demand driving gas prices upward, the competitive advantage of the Pacific Northwest will lessen markedly. That narrowing will accelerate as more energy resources are acquired on the open market. Investment in the Pacific Northwest will be affected by its declining competitive advantage in energy costs.

Third, businesses attracted to the Pacific Northwest by low electricity costs will find that attraction diminishing. Those businesses dependent on low energy costs to be profitable will suffer declining profit margins. The closure of aluminum plants in the Pacific Northwest is an early sign of the impact of rising energy prices. While the aluminum industry may be the most sensitive to rising energy costs, there are other businesses in Oregon for which energy costs comprise a significant part of final product costs. If those businesses were marginally competitive or can produce their products elsewhere at lower costs, the rising energy costs may mean that they can no longer continue operations in Oregon.

Fourth, Oregon is moving toward a competitive market in electricity, which is causing apprehension among businesses given the recent price volatility. When the 1999 Oregon Legislature was considering changing the laws to allow competition in electricity markets, many businesses were strong proponents, anticipating that a deregulated market would produce lower energy costs. Witnessing the events in California and the extraordinary price volatility, at least some Oregon businesses are having second thoughts about the move toward deregulation. The Oregon Economic and Community Development Department reports that the prospect of being thrust into a competitive electricity market is now one of the leading concerns of Oregon's businesses. Those fears may be unfounded because customers of Portland General Electric and Pacific Power will still receive the benefits of generation resources owned by those utilities, but the concern is being expressed.

Although Oregon's publicly-owned utilities and rural cooperatives are not required to participate in the competitive market, Larry Walsh of the Oregon Development Group, which provides economic development services in areas served by rural electric cooperatives, says:

> *In contrast to two years ago when many of our rural manufacturers in Oregon wanted access to market power, today a significant number prefer to work with their local utility in obtaining the best possible rates through the utility's access to Bonneville Power Administration (BPA).*

In rural Oregon, the concern about the potential adverse economic impact of rising energy costs is particularly acute. Stated simply, Oregon's rural communities, which historically have suffered higher unemployment rates than urban areas, cannot afford to lose any jobs.

Fifth, Oregonians recognize that their livelihood is based on the businesses and industries that now perceive themselves at risk. Conditions that adversely affect their jobs affect them.

In December 2000, an Oregon plywood plant announced the layoff of nearly 20 percent of its workforce, attributing the layoffs to rising natural gas prices. The rising energy costs combined with a decline in demand for housing, competition from other products and related adverse economic conditions to produce the layoffs.

On December 11, 2000, the wire services carried a story about how Kaiser Aluminum found it more profitable to shutdown its Mead, Washington plant and sell its BPA power back to BPA. The story continues that Kaiser could not only save energy costs, it could reap a windfall selling the power it bought for $22 per megawatt hour back to BPA at more than $500 a megawatt hour. The United Steelworkers of America, which represent workers employed by Kaiser, characterized the move as "unjustified

On December 27, 2000, the wire services reported that Golden Northwest Aluminum, which is the parent company of Northwest Aluminum in The Dalles, Oregon and Goldendale Aluminum in Goldendale, Washington, announced that it too would cut production from about 60 percent to about 10 percent in both plants to sell power back to BPA. The cutbacks were forecast to last until about October 1, 2001 and would affect about 400 to 500 jobs at both plants.

While in both cases the employees will receive at least some level of compensation, energy prices and market conditions directly affected jobs. In a sense, it became more profitable for these companies to sell electricity than aluminum.

The public sector is also affected by rising energy prices. With resources constrained by voter initiatives and a constitutional obligation to balance their budgets, state and local governments have little recourse to respond to energy price increases but to cut programs, services, and jobs.

b. Supply

Although the ***Oregon Energy Outlook*** assessment concludes that energy supplies are not likely to be constrained, supply constraints are possible.

For the diverse reasons cited in the assessment, the bottom line is that new energy resources have not been developed to keep pace with increasing demand. The systems used to produce and deliver energy to meet the growing demand have not been built to keep pace. The reserve margins available in the supply and delivery systems to meet growing demand are narrowing. The result is that the system has little ability to deal with problems. There is at least the possibility then that supply of electricity, natural gas, or petroleum could be constrained over the next few years.

The potential adverse impact of supply constraints is made more significant because of the interrelationships between the fuels. Natural gas increasingly is used to produce electricity. Both the price and supply of natural gas then will affect power production. Oil is used to fuel back up electrical generators for everything from hospitals to drinking water pumping stations to critical computer facilities. Oil is also used as a back up to natural gas in major industrial facilities and some power generation facilities. If low sulfur oil is used because of air quality considerations, that is the same oil used to heat homes and businesses. A surge in oil use by major industrial customers will reduce the supply and increase the price of home heating oil, which is already 50 percent above the prices of a year ago. That assumes that the major industrial customers have maintained the storage facilities to handle the back-up oil. In reality, that is not always the case, an issue that is discussed at greater length in the next section. What makes the interrelationships even more significant is that adverse conditions such as a severe Arctic cold front would put pressure on all fuel sources at the same time.

The interrelationships of the fuels is complicated by the interconnection with other markets, most notably California. California has been drawn to the edge of the energy price and supply abyss. Markets throughout the West have been affected and Oregon has been no exception. Oregon like other states is inextricably tied to California and shares in the California experience willingly or not. The California led energy price spikes of the summer have been succeeded by the supply constraints of the winter as plant maintenance deferred earlier in the year has brought California to the edge again this winter. But now, facing its seasonal peak winter heating loads and unusually cold weather, the Pacific Northwest can see the edge as well.

While near-term supply constraints are not anticipated, there are adverse conditions that could place the supply, production, or delivery systems at risk. Because investments have not been made to increase supply through new resources or conservation or delivery capabilities at a pace consistent with growing demand, there is little reserve margin to deal with those adverse conditions. Because of the interrelationship between fuels and the interconnection with other states, an adverse condition that affects one fuel or a nearby state will likely affect all fuels and neighboring states.

c. *Purchasing Decisions*

Purchasing decisions are an integral part of the discussion about price and supply. Understandably, the expectation has been that with deregulation and the changing energy markets would come choices.

Choices have come to the marketplace already to a limited extent in electricity and to a greater extent in natural gas. Customers with substantial energy use have been able to secure different kinds of contracts, including interruptible contracts. Interruptible contracts offer lower rates in exchange for the willingness to accept interruptions in energy supplies. The interruptible provisions of those contracts gave the energy suppliers assurance that they could meet seasonal peaks in firm loads, such as residential use, if the system were pushed to capacity. In the Pacific Northwest, that has usually been during the winter heating season. Those interruptions have been limited to a few days in the past and with that historical perspective, an interruptible contract may have been a prudent business decision. Unfortunately what was true in the past may not be true in the future.

In electricity, because a competitive electricity market has not yet been adopted in Oregon, the most notable interruptible contracts have been held by industries served directly by BPA. Those direct service industries included the aluminum plants. In 1995, when the BPA contracts were being negotiated, some plants chose to seek power on the open market. Those that remained with BPA have contracts that will expire in September 2001. Because BPA's offer for 2001 would supply only part of their needs, all aluminum plants have faced the need to secure additional resources on the open market. The recent dramatic increases in wholesale electricity prices resulted in costs the aluminum industry could not sustain. Plants closed or cut back production and jobs.

Interruptible contracts between investor-owned electric utilities and a few of their largest customers also have been used in Oregon. But, over the last few years these agreements fell out of favor.

In natural gas, major customers have had the option of choosing interruptible contracts for many years. Interruptible service is an integral part of the planning of gas utilities to serve the peak needs of customers who are not interruptible.

NW Natural, the predominant gas distribution company in Oregon, has eight customers who have bypassed NW Natural and about 20 special contracts with customers in lieu of bypass. NW Natural has about 100 to 125 interruptible (sales and transportation) customers on its system. Although interruptible sales are usually associated with major *industrial* customers, major *public* institutions also have opted for interruptible contracts. Oregon State University, Oregon State Correctional Institution, Oregon State Hospital, and Washington County Facilities, are examples of public institutions opting for interruptible gas or transportation services from NW Natural.

Interruptible customers were once required to have alternate fuel capability to back up the interruptible gas service. However, in 1999, that requirement was eliminated for transportation customers at the request of representatives of industrial customers. Customers receiving incentive-based gas sales from NW Natural are still required to have the capability of switching to alternate fuels. However, that requirement both in the past and now is fulfilled by a certification by the customer. In other words, NW Natural has no obligation to confirm that those customers do have alternate fuel capability. Some of them do not. Even if they do have the capability to use oil as a back up, they may not be able to do so because of air quality constraints.

Because of environmental concerns about leaking storage tanks, industrial customers were confronted with the choice in the late 1990s of removing the tanks or making costly investments to upgrade or replace those storage tanks. Many industrial customers chose to remove the tanks. In recent years, Oregon's oil suppliers have kept plants in operation by literally pumping directly from their tanker trucks into the plant. It is not reasonable to assume that the oil suppliers will be able to do that for many plants or for very long.

Air quality considerations play a significant role in two respects. First, as mentioned earlier, air quality considerations will require major customers to use low sulfur fuel oil for back up, the same fuel oil used to heat the homes of Oregonians. Over the past year, the price of home heating oil has increased about 50%. If major industrial customers switched to home heating oil as a back up fuel that would put pressure on both supplies and price. Heating oil prices will rise and as a minimum, deliveries will be delayed, especially if the tanker trucks are being used as temporary on-site storage for major customers who have no tanks.

Second, existing air quality permits may limit the amount of allowable sulfur dioxide emissions at the site. Depending on the level of emissions allowed and other sources of emissions at the site, the capability to use oil as a back up fuel may be constrained.

Emissions limitations may have been requested by the customer to stay below levels that trigger certain federal air quality regulations, or the limitations may simply have been based on "normal" oil usage projections that did not anticipate extended curtailment of natural gas. In the first case, Oregon's Department of Environmental Quality (DEQ) cannot waive federal requirements. Lifting of those emission limitations without first meeting the lengthy and expensive federal requirements would place the customer in violation of federal law and subject them to possible federal enforcement action. In the second case, the customer may be allowed to increase their emissions limits so that more oil can be used, but the customer would be obliged to request and obtain a permit revision before they exceeded their limitations. That process takes time. If there is insufficient time to revise their permit to allow increased use of oil, the customer then may face several unattractive alternatives. The alternatives might include using more expensive higher-grade or lower-sulfur fuel oil, or ceasing operation until a new permit can be secured. The customer might even consider use of oil in violation of their permit; however, deliberate violation of their permit would subject them to substantial civil penalties or even criminal prosecution. There are other options, but these options must be pursued before there is a problem.

Air quality permit revisions can be requested to provide greater assurance of the ability to use oil as a back up fuel. Although DEQ can expedite the permit review process when necessary, factors beyond DEQ's control such as total emissions at the site, the limiting effects of federal regulations, and the customer's willingness or unwillingness to reduce emissions by installing emission controls may dictate the outcome. The only way to know the outcome is to make the request before there is a problem.

For a customer that has chosen an interruptible contract there is an annual window of opportunity to acquire a firm contract. Under NW Natural's process, the customer would need to notify the company on March 31st of its request to acquire a firm contract. If NW Natural has the capacity and supply to provide the service, the customer may switch on or after May 1st. NW Natural reports that while "arranging supplies is not a problem with advance notice, that is not true for capacity" to deliver. Therefore, customers have one opportunity each year to change from an interruptible contract to a firm contract, but a firm contract is not assured. Stated differently, if there is an interruption this winter, neither a major industrial customer nor a public institution on interruptible service will have the opportunity to secure firm gas supplies.

Neither a major industrial customer nor a public institution with an interruptible service contract will have the opportunity to secure firm gas supplies this winter.

Interruptions occur when firm load requirements in effect push interruptible customers out of the pipeline. Interruptions will occur this winter just as they have in winters past. The questions are how often and for how long? Absent an unanticipated supply or delivery constraint or a significant cold weather event, interruptions should not be significantly greater than for the past several years. However, given growing demand, it is the perception of at least some representatives of the gas industry that the duration of interruptions could grow. At least some interruptible contracts in place over the last several years allow interruptions of up to 10 days. As those contracts expire, there are new contracts being offered to go into effect as early as January 1st that would allow interruptions of up to 100 days. Those contracts may simply be precautionary and not based on an expectation that there will be extended interruptions this winter or even in the next few years, but they are a statement about the industry's perception about the potential for longer term interruptions in the years ahead.

There is at least one other issue worth noting in discussing purchasing decisions and that is the choice of pricing structure. Natural gas purchasers whether they are the local gas company, major industrial customers, or major public institutions, have choices in terms of how to structure the price of the natural gas they are buying. Each approach has advantages and disadvantages. They can lock in price for a long period of time, such as a year. This approach provides stability. It may give up potential cost savings from declining prices, but also avoid price spikes. Another approach is to base contracts on monthly pricing. This approach has more volatility than a longer-term contract, which may be to the advantage or disadvantage of the customer. Finally, customers may purchase on the spot market where the price to the customer follows the daily moves in the market. This approach has the most volatility as was reflected in the period from November 1, 2000 to December 11, 2000 when prices at the Sumas, Washington delivery point increased by 841% from $4.495 to $42.300 per million BTUs. By December 29, 2000, prices were down to $10.47, but that is still more than double the cost less than two months ago.

Prices at the Sumas, Washington delivery point increased by 841% between November 1, 2000 and December 11, 2000.

NW Natural's purchases are longer term, while the purchases made for Avista Utilities are monthly. While the local gas companies do not base pricing on the spot market, other major customers have the option of securing contracts that do. Gas purchase contracts are proprietary and it is not known whether any Oregon customers buy on the spot market. If there are any Oregon customers purchasing on the spot market, they have experienced unprecedented price volatility over the last month.

2. Choices at Work

Oregonians have choices at work to manage the risk of the changing energy market. As discussed earlier, businesses and public sector organizations can choose to apply for firm natural gas contracts. They can also invest in energy efficiency, reducing their energy use. Businesses can participate in innovative new programs being offered by PGE, Pacific Power, EWEB, or through BPA and perhaps in time by other utilities to reduce peak use or generate electricity and receive financial incentives in return.

a. Energy Efficiency

There are services and financial incentives to help Oregon's business, industry and public sector improve productivity and energy efficiency.

(i) State Services and Financial Incentives

There are diverse state services and financial incentives to help Oregon's business, industry and public sector respond to the changing energy markets. These services and incentives can help them improve operating efficiency, reducing energy and other operating costs.

(a.) Office of Energy

The Oregon Office of Energy offers financial incentives to enhance the energy efficiency and productivity of Oregon businesses, industries and public agencies.

- ***Business Energy Tax Credit Program***

The Office of Energy offers tax credits to businesses to encourage them to invest in energy conservation, renewable resources, recycling and alternative fuels. The tax credit is 35 percent of the cost of the investment, taken over five years. For conservation measures, generally the energy savings must pay back the cost of the investment in more than one and less than fifteen years. Examples of projects include: energy-efficient lighting, improving energy efficiency of manufacturers production processes, and waste heat recovery systems.

- ***Small Scale Energy Loan Program***

The Office of Energy offers low-interest, long-term loans for energy conservation and renewable resources through the Small Scale Energy Loan Program. The loan program has funded innovative projects such as the recent construction of a small office building in Portland that features the use of recycled and environmentally friendly materials that is 25 percent more efficient than code requires. The loans are funded by sale of state general obligation bonds. Loans are available to homeowners, businesses, and public agencies for energy improvements.

- ***Industries of the Future***

  The Office of Energy provides technical energy advice and information to firms in Oregon's major energy-using industries on ways to help improve the energy efficiency of production. These industries include lumber, paper, agriculture, aluminum, steel, metal casting, and chemicals. Using federal dollars, the Office offers free on-site engineering consultations on ways to improve motor, air compression and steam systems. The Oregon State University Industrial Assessment Center also provides free plant energy and waste analyses.

  Oregon industries also are eligible for annual federal matching grants for adopting leading edge technologies that save energy, reduce waste, and improve air and water quality. The Office of Energy offers technical energy advice and applies for the grants on behalf of Oregon companies.

In addition, the Oregon Office of Energy offers a number of incentive, information and market development programs for energy savings and renewable energy. These programs range from energy efficient manufactured homes to telecommuting and from alternative fuel vehicles to heating duct testing. More information is available at www.energy.or.us.

(b.) Oregon Economic and Community Development Department

The Oregon Economic and Community Development Department (OECDD) is the lead state agency in working with businesses throughout Oregon. OECDD understands that while Oregon has much to offer businesses, there are a myriad of factors that can adversely affect Oregon's economy, including rising energy prices.

Rising energy prices will have the greatest impact on those businesses for which energy cost is a significant component of final product costs. A business such as high technology manufacturing may use a lot of energy, but the energy costs are a small percentage of final product costs. While even those businesses are sensitive to cost pressures that sensitivity grows in businesses for which energy costs are a larger percentage of final product costs.

The department's 12 regional development officers meet regularly with businesses in communities around the state. In those meetings, the regional development officers explore a broad range of issues of concern, including energy cost and supply issues. If needed, the department can call upon diverse resources to help businesses respond to the challenges presented by the changing energy markets.

Services are coordinated through the department's regional team structure and the regional development officers located throughout the state. Regional development officers may also call in their counterparts from the other state and local agencies involved in community solutions.

OECDD, through its Business Finance programs, offers several financial products to assist companies. These programs are offered through participating banks or in conjunction with local development groups and small business development centers. Business Finance provides financial tools that increase the capacity of private lenders to address the credit needs of small to medium sized Oregon companies.

- ***Bank Guarantee Programs***

  Business Finance offers two bank guarantee programs. Those are the Oregon Capital Access Program and the Oregon Credit Enhancement Program. These programs are designed to help banks make loans to companies that are somewhat higher in risk than traditional bank financing will allow without a partial guarantee of repayment. The Oregon Credit Enhancement Program provides loan guarantees that are focused on short term financing needs of Oregon businesses.

- ***Direct Loan Programs***

  Business Finance also offers direct loan programs such as the Oregon Business Development Fund**.** The Oregon Business Development Fund is designed to leverage bank or other private financing to help manufacturing and processing companies create or retain jobs. The program "fills a gap" in a financing package, providing a subordinate loan to complete the funding for a project. For companies facing increasing energy costs that have potential for retooling to save costs and retain jobs, these programs may provide a mechanism to finance the transition.

Manufacturers can sometimes obtain long-term, lower cost financing through the Industrial Development Revenue Bond program. These bonds are purchased or guaranteed by private financial institutions. Over 17,000 jobs have been created or saved in participating companies.

(ii) Utility Services and Financial Incentives

The utilities also offer services and financial incentives to help Oregon's business and industries use energy more efficiently. The services and incentives vary by utility, but often include technical advice, rebates for lighting improvements, and financing for efficiency improvements, including energy efficient design and construction of new facilities.

The investor-owned utilities also offer an "up-front" alternative to the five-year, state Business Energy Tax Credit. Under this program, the business can give the utility the tax credit in exchange for the net present value of the credit. That net present value acknowledges that the business benefits from having cash in-hand as opposed to a tax credit over time. The 35% tax credit over five years is traded for a payment of 28.87% today. The utilities may no longer offer this incentive once the public purpose programs of SB 1149 go into effect. The specific incentives to be offered under the SB 1149's public purpose financing for conservation have not been decided.

b. Load Management

As discussed above, utilities are beginning to offer innovative tariffs to entice industrial customers with more than one megawatt of load to voluntarily manage their loads to the benefit of the electrical system in return for financial incentives. The utilities may expand the programs to include smaller businesses.

There is value not only in businesses participating in the incentive programs offered by the utilities but in beginning to explore in earnest opportunities they might have to more effectively manage their loads. With a thoughtful, informed approach, businesses can achieve significant economic gains and improve the reliability of the electrical system, while not sacrificing productivity and jobs. Similarly, businesses could identify any emergency or back-up generation that could be called on to reduce utility loads.

c. Risk Management

If businesses have not done so already, they can take advantage of technical assistance from the utilities in risk management. There are emerging opportunities in the market to hedge risks, while taking advantage of the lower costs of interruptible contracts.

Similarly, if they have not done so already, businesses can affirm that their air quality permits will not only allow back up generation or use of oil, but allow use of back up generators to contribute to the creative "virtual power plant" being developed by utilities like PGE. The participation of businesses in the rulemaking process begun by DEQ on these issues would have benefit both in risk management and in developing new economic opportunities.

III. Energy Supplier Perspectives: Responding to the Changing Energy Market

The energy suppliers and state agencies participating in the review were asked to share perspectives on actions needed to respond to the changing energy markets. All shared information that was reflected in the report, but the energy suppliers offered other perspectives as well. A summary of those perspectives is presented in this section. The Appendix includes a more detailed description of written comments offered by three utilities. ***Oregon Energy Outlook*** presents these perspectives to stimulate further discussion of response actions.

A. State Leadership

State leadership in facilitating energy solutions, ensuring timely regulatory reviews, and completing a comprehensive review of issues associated with the move toward competitive markets was sought by some utilities.

B. Access to Low Cost Power

Electric cooperatives serving rural Oregon are very concerned about continued access to low cost power from BPA for their industrial customers.

C. Incentive Rates

New incentive rates are being offered to encourage customers to manage loads to the benefit of the electrical system and to use industrial back up generators to create a virtual electricity plant. Although the incentive rates are now focused on major industrial customers, utilities are exploring means by which other customers, including individual residential customers, can participate voluntarily in programs to reduce peak demand for electricity.

D. Managing Risk

Utilities, like PGE, are working with large customers to help them manage risk by using hedges and other risk management tools. They are exploring risk management tools such as the "weatherproof bill" for smaller customers.

E. Direct Use of Gas

NW Natural urges the Office of Energy and the OPUC to reassess the cost-effectiveness of using natural gas to produce electricity in combustion turbines when it could be used directly for home space and water heating. It encourages consideration of ways to entice developers of low-income housing to install appliances with higher energy efficiency and to support extension of service to other geographic areas.

F. Petroleum

Petroleum suppliers urged the state to explore actions needed to support development and use of other fuels, including use of refinery by-products, to lessen reliance on conventional petroleum products. New technology may make it possible to use refinery by-products to fuel industrial processes, rather than relying on heating oil.

Fuel oils must comply with sulfur content limitations to help protect air quality, and petroleum by-product fuels must also comply with sulfur content limits. The Department of Environmental Quality (DEQ) does not believe that environmental standards should be relaxed to allow burning these fuels.

Petroleum suppliers also urged the state to reconsider its use of oxygenated fuels if no longer needed to meet air quality standards. Petroleum suppliers note that oxygenated and other "designer" fuels, as they characterized them, require separate refining, distribution and storage, increasing costs and precluding use of more generally available motor vehicle fuels.

Oxygenated fuels help reduce the emissions of carbon monoxide from gasoline powered vehicles, especially older vehicles. Use of oxygenated fuel is required in certain areas of the state where carbon monoxide has been a problem, but only during the winter months. When it no longer appears that use of oxygenated fuel is necessary, DEQ has generally recommended elimination of oxygenated fuels as they have conducted planning around the state, for example, in Klamath Falls, Grants Pass and Medford. DEQ also recommended elimination of oxygenated fuels in Portland, but the local governments wanted to retain oxygenated fuels as a safety margin. They felt the risk of bringing back limits on the number of allowed parking spaces outweighed the benefits of eliminating oxygenated fuels. DEQ will review this again in the future.

With respect to oxygenated fuels, DEQ is aware that the oxygenate (ethanol) does require separate distribution and storage up to the gasoline distribution terminals. However, DEQ has been informed that some fuel suppliers are adding ethanol year round, and in locations where oxygenated fuels are not required, for reasons that are independent of regulatory requirements.

G. Renewable Resources

Electric utilities are investing in renewable resources, most notably wind power, to enhance long-term supply.

H. Internal Efficiencies

Utilities are taking action to improve efficiency and reduce costs. Those range from NW Natural completing a multi-year cast iron pipe replacement program to PGE’s commitment as part of its acquisition by Sierra Pacific to achieve $95 million in operating efficiencies.

A REPORT TO THE
OREGON OFFICE OF ENERGY

Oregon Energy Outlook

December 31, 2000

Appendix

Energy Supplier Perspectives: Responding to the Changing Energy Market

Energy Supplier Perspectives: Responding to the Changing Energy Market

1. Portland General Electric

a. Price Incentives

PGE is examining price-related incentives to improve supply. All of the options involve the concepts of voluntary participation and compensation to the customer for the savings, which will benefit the system, based on the actual market price at the time. This provides a much larger incentive than asking companies to simply "shut down" and take savings at the smaller kilowatt-hour tariff rate that they would have been billed.

b. Electricity Exchange Program

PGE's Electricity Exchange Program provides financial incentives for large industrial customers to voluntarily reduce consumption. That frees up power for everyone else at below-market cost. Since its inception in July 2000, the program has saved 32 million kilowatt hours of power, enough to supply the city of Salem for 10 days, or supply about 2,827 homes for an entire year. Forty-two percent of those savings took place in the five days between December 8th and 12th this year.

On December 8, 2000, the OPUC approved PGE's request to make several improvements aimed at making the Electricity Exchange more effective:

- The maximum one-time load reduction is now 300,000 kilowatts, up from 100,0000 kilowatts, adding greater potential for more businesses to participate.
- The program is now more flexible and easier to administer because businesses may sign up as much as one week in advance and can participate for as long as they want and the need exists.
- The program now offers more realistic prices based on prevailing market rates. Prices can be prescheduled specifically for on-peak and off-peak blocks of time instead of "real-time: pricing limited to 16 hours in a 24-hour period.

PGE is also looking for means by which other customers, including individual residential customers, can participate voluntarily in similar demand-side programs. The challenges include managing the program so the smaller savings generated by smaller customers is cost-effective, and finding a reasonably accurate system of projecting savings from customers' meters. The conventional meters used for the smaller loads do not track time-of-use or peak use and instead simply record the total electricity used.

c. Role of State Government

(i) Facilitating Solutions

If Oregon is to improve the supply of electricity (improving reliability and stabilizing prices), PGE concludes that it needs the support of state government. From PGE's perspective, government would serve the public interest by facilitating solutions to the problem and by expediting the various approval processes:

> *Overall, various state regulatory agencies affecting development of or expansion of power sources (including efficiency programs) should coordinate efforts across a broad spectrum: Energy Office, DEQ, OPUC, etc., with a goal of minimizing delay in implementation.*

(ii) Timely Regulatory Review: Air Quality

PGE is developing an innovative program, Dispatchable Standby Generation (DSG), where large private generators that would normally sit idle can feed the grid to meet peak needs. Obtaining an air quality permit for each site (potentially dozens), rather than for the entire project, makes the process very cumbersome and duplicates effort for the state. PGE argues that covering the entire project with one permit would make more sense. While both options are possible, the limiting effects of Federal regulations and/or the lack of clear permitting rules addressing back-up/peaking generators results in reluctance to apply for the necessary permits.

The Department of Environmental Quality and its governing body, the Environmental Quality Commission, have said that they will start the process to develop appropriate rules to address back-up/peaking generators.

(iii) Comprehensive Review of Competitive Market

As various policies, rules and procedures are created under SB 1149, PGE urges the state to carefully examine each, in consultation with energy suppliers and consumer groups, to make sure that they do not create further barriers to new or improved energy supply.

d. Rising Energy Prices

PGE realizes that rising prices have an impact and the utility has taken actions to address those rising costs.

(i) Risk management

PGE has worked with businesses to manage price risk and is exploring new programs to help residential customers:

PGE helps large customers manage financial risk by helping them acquire hedges and other risk management tools. We're also exploring risk management tools for smaller customers, such as the "weatherproof bill" concept we hope to formally introduce next year. (This would be a flat monthly rate, regardless of usage, with no "true-up." As with any other risk management device, it would provide customers with certainty against the uncertain prospect of a very cold winter bringing very high bills.)

(ii) Contract adjustments

During the rapid run-up of wholesale prices this summer, PGE worked closely with companies who were on market-based contracts to negotiate new agreements that would stabilize prices without impacting rates of other customers, or to move those firms back to the regulated rate schedules.

(iii) Energy efficiency and low-income assistance

PGE is using a variety of approaches to help customers deal with rising prices, including company sponsored energy efficiency and weatherization programs, greatly increased donations (of shareholder money) to low-income programs, innovative new programs to reduce consumption or increase supply during peak demand, increasing the efficiency of its largest generation plant, and facilitating development of a new generation plant.

(iv) Internal efficiencies

PGE, as part of its on-going self-evaluation and the rate filing process, has looked at ways to improve its own efficiency to minimize costs to customers over the long run, while improving the level of service. This includes the substantial upgrade and efficiency improvement at the Boardman plant, investment in new information technology, and the purchase of a new customer information system.

As part of its acquisition by Sierra Pacific Resources, PGE pledged $95 million dollars in efficiencies, which will be directly credited to customers over seven years.

e. Renewables

PGE is increasing its investment in and purchases of renewable resource-based power, especially wind power, because of its long-term supply potential.

2. Pacific Power

Pacific Power is very concerned about the impact of high prices and limited supply on its industrial, commercial and residential customers.

a. Load Management

Pacific Power is considering programs that would provide customers with incentives for not using high-energy appliances and other devices during peak times, such as late afternoon and early evening. Doing so would help reduce demands on the regional system during peak hours. It also would decrease the frequency with which Pacific Power is required to purchase supplemental power at the most expensive times of day. Pacific Power is considering beginning to offer programs in selected areas in 2001 and may expand as appropriate later.

On December 8, 200, the OPUC approved a demand-side bidding/buy back program for Pacific Power similar to programs offered to industrial customers by the BPA and Portland General Electric. From Pacific Power's perspective, a key feature involves a posted price for customers who want to voluntarily participate in the program.

Pacific Power is also in discussion with some customers regarding coordinating their energy consumption planning and schedules, such as maintenance shutdowns, with the Company's load requirements.

b. Energy Savings Campaign

Pacific Power is teaming up with an energy office in another state to develop an aggressive energy savings campaign, "Save It." The campaign, which includes public service announcements, emphasizes the broader benefits of energy savings in such areas as the environment and economic development. The goal is to change usage patterns away from peak times by focusing on how doing so benefits the community.

Pacific Power would welcome a partnership with the Oregon Office of Energy to develop a similar campaign in Oregon.

c. Energy Efficiency Investment

In addition to the above projects, Pacific Power committed $7.3 million to Oregon-based energy efficiency projects in 2000 and expects to expend at least that much in 2001.

3. NW Natural

NW Natural believes a comprehensive review of Oregon's energy policy should be conducted. The review should consider how the changing market will affect the development of energy resources and infrastructure, how the regulatory process can be responsive to these changing market conditions and whether public policy approaches to energy issues should be modified.

NW Natural outlined three specific areas for further state review and cited initiatives it has taken to improve internal efficiencies.

a. Areas for Further State Review

(i) Use of Gas-Fired Combustion Turbines

NW Natural would urge the Office of Energy and the Oregon Public Utility Commission to reassess the cost-effectiveness of using natural gas to produce electricity in combustion turbines when it could be used directly for home space and water heating:

> *As a natural gas distribution company, NW Natural is worried about the electric industry's near total reliance on natural gas for producing its incremental supplies. The company recognizes that there are few alternatives to natural gas generation, but is concerned that the demand from electric generation will constrain pipeline capacity and put upward pressure on the prices for natural gas supplies. These costs may be unfairly borne by native load natural gas customers if new pipeline costs are rolled into existing rates. Furthermore, if this new electric generation is used to serve end uses that could have been served directly by natural gas, then we are reducing energy efficiency and environmental quality, as well as wasting a valuable fuel. As the region builds new gas-fired turbines, public policies should be in place to: (1) assure that electric generators pay for the cost of the pipeline capacity that serves them; (2) encourage the direct use of natural gas*

where appropriate; and (3) capture the highest efficiency source to use of each form of energy available.

(ii) Direct Use in Multi-Family and Low-Income Housing

NW Natural suggests that the installation costs of electric space and water-heating systems may be lower than natural gas systems, but the operating costs are higher. As a result, particularly low-income housing has lower construction costs, but higher operating costs.

> *The multi-family and low-income housing market tends to be constructed using electric space and water heating. Many individuals and businesses that are developing single and multi-family housing for low-income customers are focused on keeping the rent low and, as a result, do not focus on the operating costs of the apartment. There is little financial incentive for the developers of these units to install appliances with higher energy efficiency.*

(iii) State Incentives to Expand Infrastructure

NW Natural recommends that the state examine ways to expand Oregon's energy infrastructure.

> *Rate treatment, tax policies, environmental policies, economic development programs and other mechanisms should be reviewed to determine the effect they have on the construction of generation, transmission and distribution facilities. The review should also encompass the delivery of energy to marginal areas where the traditional line extension policies (which are based only on the utility's economics) indicate that the costs to existing customers do not warrant extending service.*

b. Internal Efficiencies

NW Natural recently completed a multi-year cast iron pipe replacement program. This replacement program was performed to increase the operating efficiency of its distribution system, reduce energy losses and increase safety.