DIRECT USE OF NATURAL GAS: ANALYSIS AND POLICY OPTIONS

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Introduction

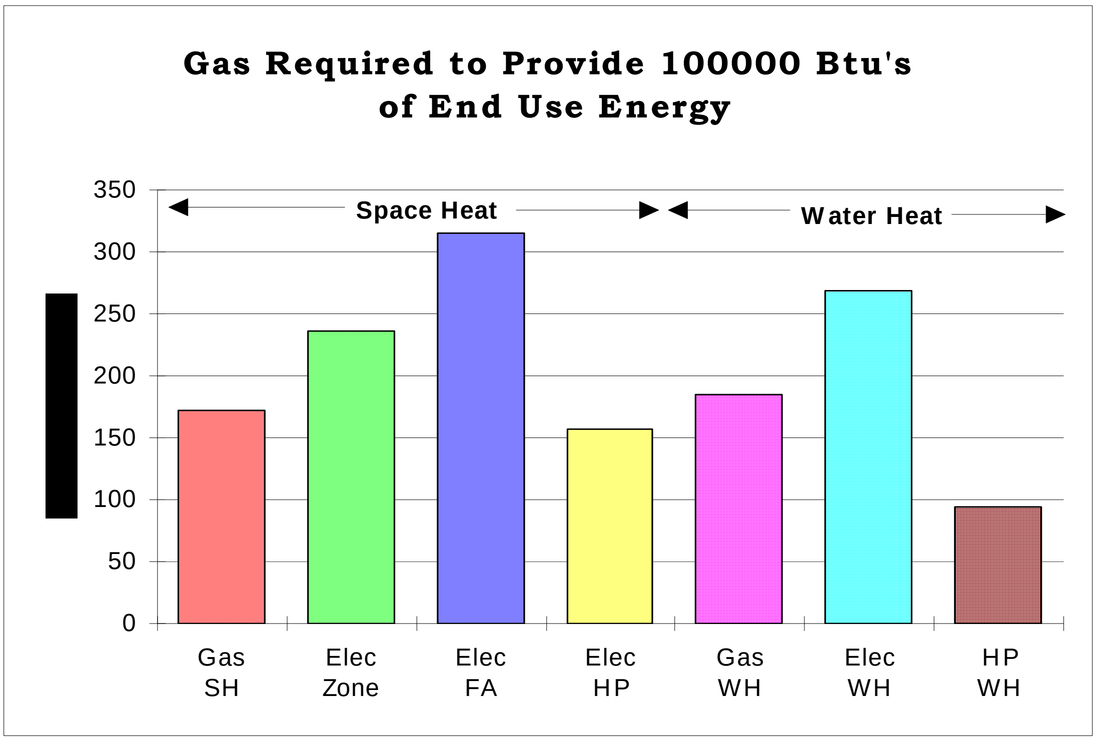
Lower natural gas prices, apparently adequate gas supplies and improving reliability and efficiency of combustion turbines have all increased the attractiveness of natural gas as a fuel for electricity generation. In the Northwest Power Planning Council's 1991 Northwest Power Plan, both natural gas-fired cogeneration and the use of combustion turbines as a means of backing up the hydropower system in low water years were found to be cost-effective resources. In conjunction with the hydropower system, combustion turbines would be used only when water conditions limit the supply of nonfirm or so-called secondary hydroelectricity. With today's lower natural gas price outlook, natural gas is competitive even as a base-load electricity generation resource, that is, to operate at high capacity factors to meet loads during most conditions.

Considering the use of natural gas-fired generation for meeting base-load electricity demands raises the issue of whether it is better to use natural gas directly for appropriate end-uses, such as space and water heating, than to burn natural gas to generate electricity to serve the end-use energy needs. When applied to existing buildings or industrial plants, this issue is referred to as "fuel conversion." When considered for new applications it is called "fuel choice." In general, it is a question of total energy efficiency.

A simple argument that carries substantial intuitive appeal is that it is more energy efficient to burn natural gas directly for space or water heating than it is to generate electricity with it. The energy content of the electricity generated in a combined-cycle combustion turbine, for example, is only 45 percent of the energy content of the gas burned to generate it. In contrast, direct use of natural gas to fire a home furnace would make use of 80 percent of the original energy content of the gas as heat for the home. To be a valid energy comparison, however, other considerations have to be introduced, such as the efficiency with which electricity is converted to useful heat in the home and the duct and flue losses associated with different types of heating systems. Such considerations make the comparison less clear, but the direct use of natural gas is more energy efficient for many conventional heating systems.

Figure 1 shows a comparison of the total gas requirements for space and water heating with various electric and gas systems. The gas requirements for the electric systems are calculated assuming that the electricity is generated using a combined-cycle combustion turbine. Figure 1 shows that forced-air electric heating systems require about twice as much gas as a gas-fired forced-air system. Zonal electric heating systems, where rooms are independently heated without central furnace or ductwork, while considerably more efficient, still require more total gas than direct use of gas for home heating.

Figure 1: Natural Gas Required to Provide 100,000 Btu of End-Use Energy.



Assumptions:

Gas furnace efficiency - .78
Duct efficiency - .75
Electric heat efficiency - 1.0
Heat pump efficiency - 2.0
Electric water heat efficiency - .88
Combined-cycle combustion turbine efficiency - .46
Electric transmission and distribution efficiency - .92
Heat pump water heater efficiency - 2.5
Gas water heater efficiency - .54

However, Figure 1 also shows that there are technologies, such as heat pumps, where electricity provides end-use services with less total gas use than a conventional gas furnace. This may also apply in many industrial and other applications. In addition, the comparisons in Figure 1 would be altered in cases where the insulation levels and other thermal characteristics differ between gas and electric heated homes as is currently the case for new homes in Washington. The important point is that whether natural gas or electricity is more energy efficient depends on specific technologies and physical home characteristics. Technologies and home building practices continually evolve and change the comparisons and conclusions. For example, gas-fired heat pumps have been developed and will soon be generally available.

The above reasoning for conventional space and water heating has led to arguments that the Council should encourage the direct use of natural gas as an electricity conservation program. It would be an energy-efficiency action that reduces electricity demand.

The Council, however, has never adopted <u>energy</u> efficiency as its planning criterion. The Council's plans are based on <u>economic</u> efficiency, which is a much broader concept focused on total costs, rather than pure energy efficiency. Further, the Council has focused on economic efficiency of electricity services, as mandated in the Pacific Northwest Electric Power Planning and Conservation Act, not on total energy efficiency. Total energy efficiency, however, is an important social objective that the Council has considered in its past decisions to some degree.

An economic analysis of the direct use of natural gas compared to the use of electricity must consider all of the costs associated with the two alternatives from the original fuel source through its transmission and conversion to the ultimate product. The ultimate product in this case is hot water or temperature-controlled interior space. Thus, for electricity the costs include the cost of the natural gas and of its transportation to the combustion turbine, the losses of energy in converting the natural gas to electricity in a combustion turbine, the losses and cost of electricity distribution and metering and any losses or gains involved in conversion of electricity to useful heat in the home. In the case of natural gas, the costs of distributing gas to homes and metering consumption need to be added. The losses of converting natural gas to a useful form of energy are now experienced in the home instead of in a combustion turbine power plant. In both cases, the costs of any required capital investments must be included. In general, end-use equipment is more costly for natural gas than for electricity, but for electricity the cost of the electricity generation plant must be considered. Finally, the environmental costs associated with each alternative must be evaluated. It is this evaluation of total costs that has been the Council's planning focus.

Now that regional utility and industrial plans indicate a substantial future role for natural gas in generating electricity, a number of new relationships between natural gas and electric utilities will develop. It is no longer the case that, if a natural gas distribution company loses a heating customer to an electric utility, total sales of natural gas will be lower. Now it is likely that the new electricity requirements will be generated by burning natural gas, probably more than the customer would have consumed directly. It becomes an issue of which customer the gas industry will serve directly — the ultimate user or the electric utility. Of course, the role of local gas distribution companies may be different in the two cases.

Further, it is becoming increasingly difficult and unpopular to support unconditional competition to sell energy resources. Wise stewardship of limited resources and careful consideration of the environmental effects of consuming those resources have become important elements of public policy. This implies that it may be desirable to ask what is the best way to serve particular energy service needs. For example, what is the best use of natural gas, to serve end uses or to generate electricity? If there are clear advantages on either side, should society try to influence the choice or is the market adequately informed and structured so that the most efficient choice will be made without policy intervention?

This issue paper reviews previous Council analyses and policies regarding direct use of gas. It also reviews several studies that have been done by others in the region addressing this topic. Most of these studies were addressing fuel switching or fuel choice issues.

The paper then makes use of the information generated by these studies and additional analysis to evaluate questions of the cost-effectiveness of fuel switching or fuel choice programs within the context of the Council's power plan for the region. Finally, comments received on the draft paper are summarized and a Council policy conclusion on the role of direct natural gas use is presented.

Past Council Analyses and Positions

The Council has not taken a strong position to encourage particular fuel choices in its past power plans. However, the issues of fuel conversion and fuel choice have been thoroughly examined and considered in developing the plans.

In developing its first (1983) power plan, the Council contracted with Synergic Resources Corporation for a thorough evaluation of the fuel conversion potential in the region. That study and a staff issue paper on the subject helped frame the Council's policy in the 1983 plan. In essence, that policy was that fuel conversions are not a form of electricity conservation. The plan stated that "..conservation involves the more efficient use of electricity."[1] It was further stated that the Council's policy is neither to encourage nor discourage the use of any particular fuel.

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[1] 1983 Northwest Conservation and Electric Power Plan, Volume I, Page 7-1.

Since the first power plan, the Council's policy has remained essentially unchanged. However, there has been a growing concern that electricity efficiency programs should not adversely affect the choice of natural gas as an end-use energy form. There also has been an increased recognition that the electric and natural gas industries need to better coordinate their planning as the two industries become increasingly interdependent. Appendix A contains a more detailed discussion of the development of Council fuel policies and studies done in support of, or as a result of, those policies.

Regional Analyses of Direct Gas Use

Several studies have been done by organizations and individuals in the region addressing the issues of fuel conversion and fuel choice. These studies have various scopes, address different regional areas and focus on different sectors and end uses. However, it is useful to break these studies into two general types. One type focuses on the cost-effectiveness of alternative fuel choices and efficiency levels in new buildings, and the second type focuses on determining fuel conversion potential in existing buildings. This section summarizes the important findings from these studies. A more detailed discussion of the individual studies is included as Appendix B.

Studies of fuel choice economics for new houses have been done primarily in support of the development of building efficiency codes in Oregon and Washington, but also include a study by the Council staff. The clear implication of these studies is that the economics of fuel choice is not a simple matter of energy efficiency. It is not possible to reach a simple conclusion that one fuel or the other is always a more cost-effective choice. Analysis invariably leads to the finding that the most economic fuel choice is very sensitive to the amount of energy required to heat a home. Thus, the answer depends on house size, climate and thermal efficiency of the house shell. In addition, the results depend on the relative prices of natural gas and electricity and the expected relative escalation of these prices over time.

A number of studies have been done over the last few years that address the potential electricity savings that could be achieved by converting existing electric space and water heat to natural gas. The Council study, done by Synergic Resources Corporation, was an early forerunner of these studies. More recent studies have been done by or for state energy offices and individual electric and gas utilities. As a general rule, these studies begin with estimates of the number of residences having electric space or water heat. Various levels of potential savings estimates are then developed. The least refined level of estimate is often referred to as "technical potential." Technical potential generally ignores many of the economic and practical limitations on fuel conversions and thus provides the largest estimate of savings.

"Cost-effective potential" estimates trim out the applications where, for various reasons, the conversions would not be cost-effective. "Resource potential" estimates further reduce the savings by subtracting an estimate of what could be expected to occur naturally in the market without encouragement by specific fuel conversion policies. Table 1 summarizes the results of studies that were done for the residential sector in the four Northwest states. Appendix B contains descriptions and references for these studies.

Table 1: Summary of Residential Sector Fuel Conversion Resource Estimates (in Megawatts)

Study	Technical Potential	Cost-Effective Potential	Resource Potential
Lazar	1,448		
Bonneville			385
WSEO	1,370	854	630
Aos & Blackmon	1,483	1,038	845

Perhaps the most important conclusion to draw from Table 1 is that the fuel conversion resource potential in the residential sector is between 385 and 845 average megawatts. This compares to a total new resource need of over 6,000 average megawatts in the Council's 1991 power plan by the year 2010. About 2,000 of the 6,000 megawatts were expected to be natural gas-fired. With the revised natural gas price outlook (revised in 1993) and new turbine efficiencies, that number would likely be larger. Fuel conversion programs may have significant resource potential, but they would not displace the need for significant amounts of gas-fired generation additions over the next 20 years.

As was the case for new homes, the cost-effectiveness of fuel conversions was found to be highly dependent on the amount of energy used in a home. Therefore, house size, climate and thermal efficiency are very important determinants of whether it is cost-effective to convert from electricity to natural gas. Other key elements that determine cost-effectiveness include fuel prices and expected escalation, capital costs of end-use equipment conversion, cost of extending gas service to the home and avoided costs of electric and natural gas resources. The determination of resource potential requires estimation of what the market is likely to convert in the future. The inherent uncertainty of the future is compounded in this case by a lack of understanding of even historical and current fuel choice behavior.

It is important to note that most of the studies done to date have only addressed these uncertainties in very limited ways. Most results were based on estimated average conditions and costs. A better understanding and assessment of these uncertainties is needed to help the Council reach decisions about its direct gas use policies. A particular need is to better understand how current fuel choice and conversion markets are working. This is explored in the following section.

Fuel Choice Markets

Interest in programs that influence fuel conversion and fuel choices has been growing in the region, driven by energy-efficiency arguments and made even more appealing by the improving economic and political attractiveness of natural gas. The studies cited above are evidence of growing interest, but some organizations have moved beyond studies to conduct experiments in fuel conversion programs and, in one case, to run an aggressive fuel conversion program. This regional experience in fuel conversion programs is described briefly in Appendix C.

Programs to influence fuel choice in new applications are also being explored. But programs to change market behavior should not be attempted without first examining the market. There are two reasons for this. First, if the market is found to be working well and is free from serious distortions, then the rationale for interfering is weak. Second, if policies are needed in order to reach a more efficient result, understanding the market will help design programs that are more likely to be effective. For example, we are finding that the ability to deliver conservation as a cost-effective resource can be threatened by inefficient program design and implementation.

It is difficult to establish whether a market is working effectively or not. One can look at historical responses to price change if sufficient data is available, but that can only establish whether the direction of change seems appropriate. The degree of change could still be constrained by market limitations. Another approach is to examine the structure of the market and the pricing of the products for obvious market problems. This section will briefly look at both theoretical market problems and at past market changes in the energy industry.

Both electricity and natural gas distribution are regulated monopolies or publicly owned utilities. Thus, neither the market for electricity nor the market for natural gas could be considered to be competitive. However, the market for energy, in general, is not a monopoly. Consumers do have choices about what type of fuel they use to produce energy services and also can invest in more efficient equipment or buildings to affect the amount of energy they require. There has been a history of lively competition among electricity, natural gas, oil and other energy sources for residential space and water heating markets. This competition continues today in various degrees throughout the region and, in fact, colors much of the growing interaction between the electricity and natural gas industries.

Nevertheless, there are several frequently cited imperfections in energy markets. These include average cost pricing, lack of consideration of the long-term marginal cost of natural resources, environmental externalities and imperfect knowledge of efficiency options. Most of these affect different energy sources about equally. However, the first, average cost pricing, clearly affects the electricity market more significantly than it affects the fuels markets. This is especially true in the Pacific Northwest where electricity is produced primarily from hydroelectric facilities at a very low price, whereas growing electricity needs must be served by new generation or efficiency improvements, both of which cost more. As a result, consumers make electricity decisions based on prices that are lower than the marginal cost the region faces for new electricity supplies. This pricing problem affects both the fuel choice decision and electricity efficiency decisions.

For natural gas and oil the problem is less severe. Much of the cost of these energy sources is for the fuel itself instead of for the capital cost of the generating plants as in the electricity industry. The wellhead costs of natural gas and oil have been freed from regulation and now reflect at least short-term marginal costs. Thus, electricity has been granted a competitive advantage over natural gas through its cost structure (greater capital intensity) and average cost pricing regulation.

The inherent advantage of electricity in fuel choice is much more basic than just regulatory treatment, however. Electricity serves several of the basic requirements for modern living that natural gas cannot serve efficiently. Thus, any new housing development is certain to include the cost of extending electrical service to provide lighting and power for electrical appliances and communications. Electricity is also capable of providing other end-use services, such as space and water heating, that could be provided by natural gas. But natural gas service often requires an additional customer investment in gas service extension. Compounding this first cost issue is the fact that a greater proportion of electric distribution costs are covered generally by the body of rate payers rather than by new customers. This may be due to deliberate policies to ensure that all citizens have access to electricity for lighting and appliances. Natural gas has not traditionally been viewed as such a basic necessity. There have not been large-scale programs to make natural gas available to all citizens as was the case, for example, with rural electrification.

In many ways, the market structure affecting fuel choice is similar to the market for electricity conservation. There are similar issues of inadequate information, utility incentives and inefficient electricity pricing. In the case of electricity conservation, society has chosen in many circumstances, including the Northwest Power Act, to intercede in the market. However, there is an important difference between fuel choice markets and electricity conservation markets. There is a large well-organized natural gas industry that markets natural gas and provides information and assistance for fuel conversions. There is no such market for energy-efficiency. In the following sections, the evidence on how fuel choice markets are working is examined and compared to the Council's forecast of electricity demand.

Related to the new home fuel choice market is the long-standing issue of whether the payment of electricity efficiency program incentives causes an increased selection of electric space and water heating. In the 1991 power plan, the Council asked Bonneville to monitor its energy-efficiency programs to see if they were affecting fuel choice. The particular programs of concern were the Long-term Super Good Cents program and the Manufactured Housing Acquisition Program (MAP).

In response to the Council's concern, Bonneville conducted studies of the fuel choice effects of incentive payments in both of these programs. The analysis of the Long-term Super Good Cents program showed that the availability of incentive payments did cause an increased choice of electric heat in new homes where gas was available. However, because gas was only available in 18 percent of the cases, the electric-efficiency savings were the dominant effect of the program incentives. Nevertheless, Bonneville has made adjustments to the incentives paid in the program to reduce the potential market distortion.

In the case of the MAP, the study showed that the gas-heated share of manufactured homes dropped from 10 percent to about 4 percent since the program began. The study also concluded that other factors, such as less liberal line extension policies and reduced marketing efforts by gas utilities, which occurred coincidentally with the implementation of the MAP program, contributed to this reduced market share. Again, the dominant effect of the program has been to dramatically improve the efficiency of electrically heated manufactured homes in the region. Increased national efficiency standards for manufactured homes will lead to lower incentive payments and less fuel choice distortion, but utilities are looking for ways to bring natural gas into the program so that a market bias toward electricity choice is avoided while maintaining electricity savings.

It is important to find ways to achieve electricity efficiency goals without impeding consumer choice of gas where it is available and cost effective. To the extent that new homes are induced to use electricity for heating when they would have used gas, the increased electricity use partially offsets the efficiency savings, causing the cost of efficiency savings to increase on a per kilowatt-hour basis.

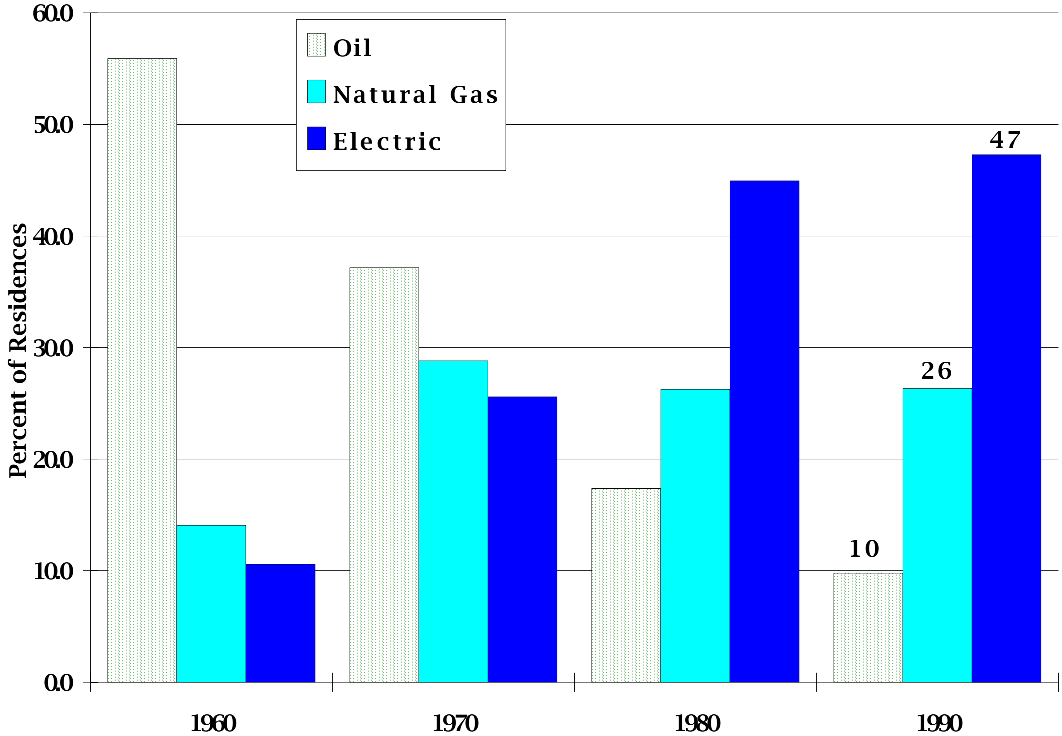
<u>Fuel Shares Information</u>

There have been significant changes in fuel shares and fuel choices over time in the region. The amount of data that is available is too sparse to facilitate careful analysis, but some trends can be shown. The available data shows that the roles of different energy sources change significantly over time as technologies, prices and other factors change.

The most comprehensive data over a long period of time is the census information on fuels used for home heating. This information is for the entire stock of homes in the region at a particular time and thus is a fuel share estimate. It does not address the question of what fuel choices are being made in new homes in a particular year, for example, but it does reflect the cumulative effect of past fuel choices.

Figure 2 shows the regional home heating shares of oil, natural gas and electricity for 1960, 1970, 1980 and 1990. The most dramatic trend is the reduction in the share of oil heat. This is a trend that was strongly under way even before the large oil price increases in the early 1970s, and it has continued since the oil price collapse in the mid-1980s. Over the 30 years between 1960 and 1990, the oil share of home heating fell from 55 percent to 10 percent of homes. The share of natural gas increased from 13 percent in 1960 to 28 percent in 1970, but then stabilized around 25 percent. (Natural gas was not available by pipeline in the Pacific Northwest until 1956.) Unlike oil, the natural gas trend appears to have been stemmed by the increased price and supply concerns that occurred during the 1970s and early 1980s. Electricity increased rapidly in share between 1960 and 1980, from only 10 percent in 1960 to 45 percent in 1980. Electricity's share appears to have been affected by large increases in electricity prices during the late 1970s and early 1980s, as the share leveled off around 45 percent. Not shown in Figure 2, is an "other fuels" category that includes wood, propane and a few other miscellaneous fuels.

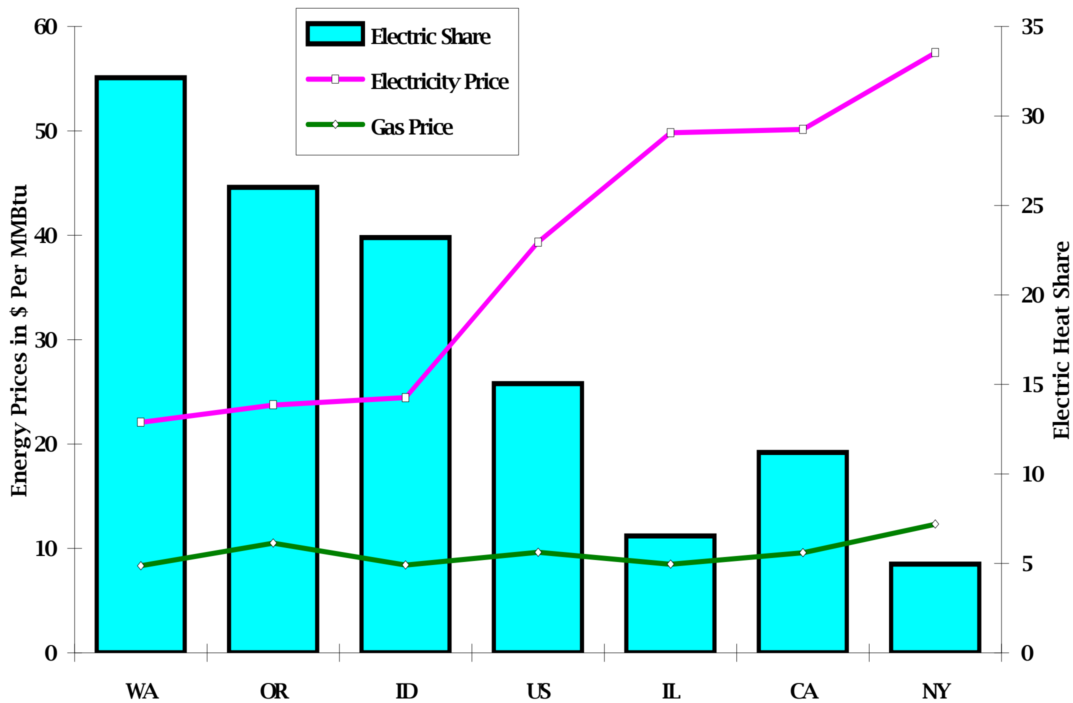
Figure 2: Changing Fuel Shares for Northwest Home Space Heating



Another way to view how fuel shares have responded to price differences is to compare fuel shares and prices for different regions or utility service areas. While natural gas prices are similar across states, electricity prices vary significantly. Comparing electricity price and electricity space heating shares across states makes it clear that in the long run, markets do adjust to different energy prices and can result in dramatic differences in fuel shares.

Figure 3 compares 1990 electricity and natural gas prices to electric space heating shares for Washington, Oregon, Idaho, the total United States, Illinois, New York and California. Electricity prices in the three non-Northwest states were more than double those for the Northwest states. The bars show that higher electricity prices are accompanied by much lower electric space-heating shares. Whereas Northwest electric shares vary from 40 to 55 percent, the shares for the other states shown in Figure 3 vary from only 9 to 19 percent. Conversely, natural gas heating shares for the Northwest states range from 22 to 28 percent compared to 73 percent in California, 80 percent in Illinois and 46 percent in New York. New York's natural gas share is lower because many more homes are heated with oil than in most other regions.

Figure 3: Comparison of State Electric Prices and Heating Shares



Within the Northwest, electricity prices vary significantly between publicly owned utility service areas and investor-owned utility service areas. Bonneville Power Administration allocated 1990 Census Data to utility areas using zip code level data.[2] The average electric heating share for the region was 48 percent, consistent with the 1990 bar in Figure 2. However, for publicly owned utility service areas the electricity share was 60 percent compared to 41 percent for investor-owned utility service areas. This pattern is consistent with incentives provided by electricity price differentials between residential customers of investor-owned utilities, at 5 cents per kilowatt-hour in 1990, and customers of public utilities who paid 4 cents. In addition to the price differentials, and partly because of them, natural gas is more readily available in investor-owned utility service territories. The Bonneville Power Administration recently completed a survey of homes in the region, the 1992 Pacific Northwest Residential Energy Survey (PNRES92). It showed that gas was available to 35 percent of investor-owned utility customers, but only to 18 percent of publicly owned utility customers.[3]

Fuel Choice in New Homes

The discussion above illustrates that fuel choice markets do respond to economic signals over the long-term. Persistent differences in energy prices are reflected in fuel choice in different parts of the country and also between utility service areas. Although Northwest electricity prices remain well below prices in

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[2]Communication from Ottie Nabors, Bonneville Power Administration, February 21, 1993.
[3]Communication from David Mills, Bonneville Power Administration, September 29, 1993.

other areas of the country, the region has experienced both significant increases in electricity rates and decreases in natural gas prices over the last several years. The response to these changes can best be measured by looking at how the choice of space and water heating fuels for new homes is changing. These shares of new equipment purchases are often referred to as penetration rates. The most appropriate measure of market performance would be the share of natural gas in new homes built where gas is available. However, there is little data on gas availability and, as a result, fuel shares are reported as the share for all houses.

Bonneville's 1992 survey documents a significant shift toward natural gas and away from electricity as a heating fuel.[4] Homes built between 1986 and 1988 were 58 percent electrically heated and 23 percent natural gas heated. Homes built between 1989 and 1992 were down to 52 percent electric and up to 33 percent gas. Most of the remaining new homes in both periods were heated with wood and, to a lesser degree, propane. The wood-heated share decreased from 13 percent in the earlier period to 9 percent.

To address the question of gas share where gas is available, a special tabulation of the PNRES92 survey was provided by Bonneville.[5] Although, as noted above, the share of all homes built between 1989 and 1992 that used gas space heating was 33 percent, the share of gas space heat where natural gas was available was 75 percent. Homes not heating with gas where gas was available used electricity (18 percent), wood (5 percent) or other fuels (1 percent). About a third of those using electricity were heat pumps.

Another source of fuel penetration data is the Oregon Public Utility Commission. The Commission has collected information on space and water heat fuel shares for new homes built in Oregon since 1978. An examination of this data gives some insight into the changes in new home fuel choice patterns over the last 13 years. The data shows that the share of new homes using natural gas for space heat has been increasing since 1978. Gas space heat penetration rates, averaged for all housing types and utility service areas, increased from 16 percent in 1978 to 31 percent in 1991. Water heat shares were only available after 1986 but appeared to be very similar to the space heat shares during the latter part of the same period.

Most of the natural gas space heat occurs in single-family, site-built homes. For example, in 1991, 55 percent of new single-family homes in Oregon chose natural gas for space heating. However, 94 percent of new multifamily and manufactured houses chose to heat with electricity. Figure 4 shows the trends for the three different housing types. There appears to be little trend in the Pacific Northwest toward the use of natural gas for multifamily or manufactured houses. In this respect, the region is not typical of the rest of the country where gas share

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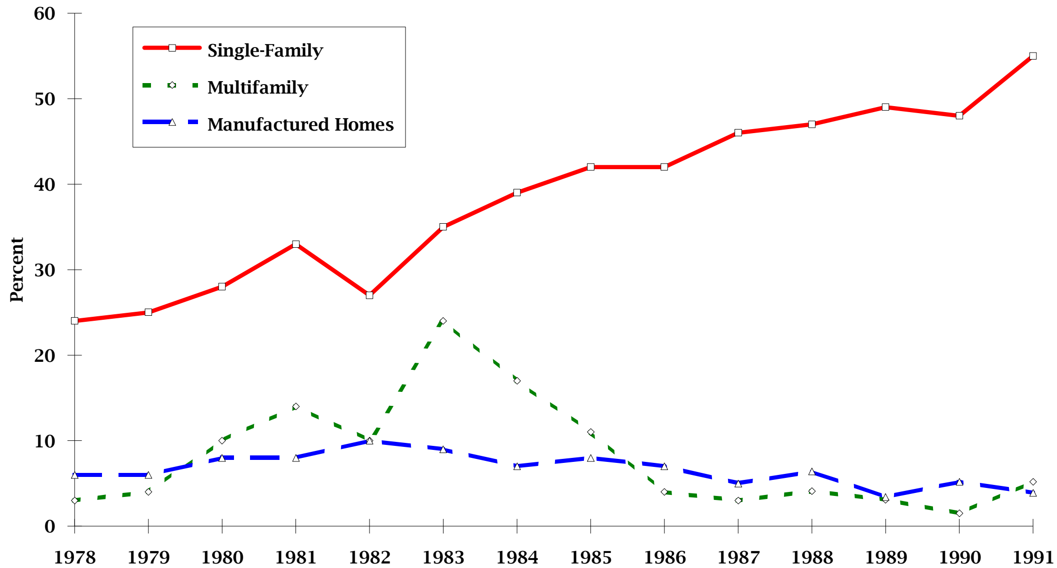
[4]Communication from Ottie Neighbors, Bonneville Power Administration, March 23, 1993.
[5]Communication from Ottie Neighbors, Bonneville Power Administration, December 1, 1993.

in multifamily homes is about 50 percent and has been increasing in recent years.[6]

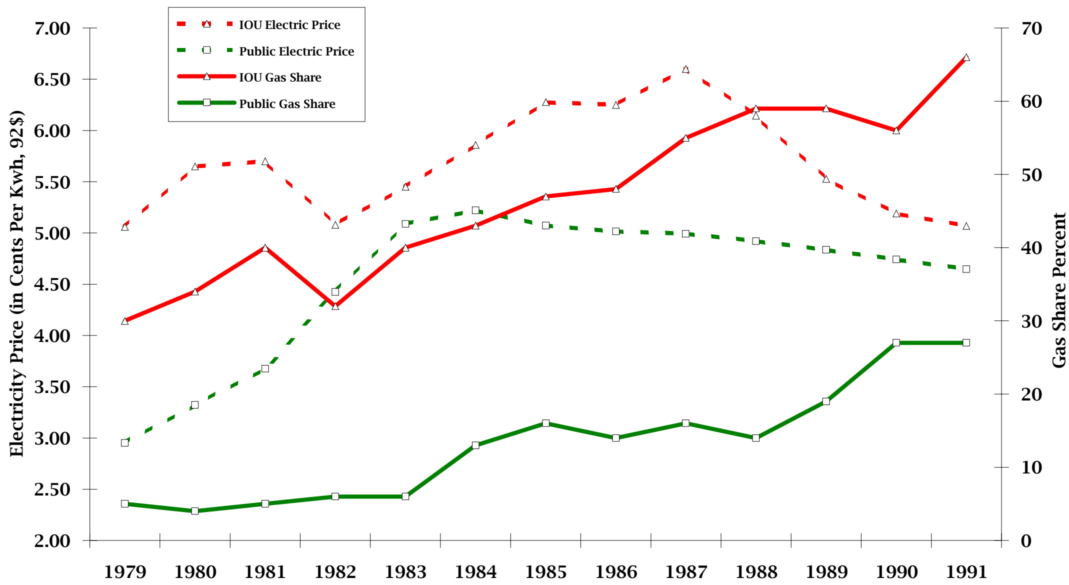
Figure 4: Residential Gas Space Heating Penetration Rates in Oregon New Construction



The Oregon Commission's fuel penetration data for Oregon, when combined with electricity prices and shown separately for public and investor-owned utility service areas, further illustrates the market response of fuel choices. Figure 5 plots natural gas penetration rates for new single-family houses as solid lines; the dashed lines show real (adjusted for inflation) electricity prices for the two utility types.

Figure 5: Electricity Prices and Gas Space Heating Penetration in Oregon, by Utility Type

[6]Northwest Natural Gas Company, Multifamily Market Study, March 1994, page 9.



Comparing the dashed lines illustrates the difference in residential electric rates between public and investor-owned utilities. Comparing the solid lines shows that the penetration of natural gas for heating new homes in investor-owned utility service areas has been more than double the rate in public utility service areas. In addition to the electricity price differences, this may also reflect a greater natural gas availability for investor-owned utility customers. As noted above, this is true for the region, and it is likely the case in Oregon as well. It should be recognized, however, that the gas availability difference itself may partly reflect the electricity price difference as well as a different urban/rural mix. The graph shows that the penetration of natural gas continued to increase even after real electric rates began declining. This is partly because natural gas prices were declining during that time.

<u>Fuel Conversions in Existing Homes</u>

The evidence above, as well as reports by both gas and electric utilities, indicates that natural gas is capturing most of the new single-family home market where gas is available. However, most of the discussion and analysis of possible energy-efficiency gains relate to fuel conversions in existing homes that use electricity for space or water heating. Unfortunately, information on fuel conversions in existing homes is much harder to find than information on new home fuel choices.

Bonneville's PNRES92 survey included a question that asked if the household had changed heating fuels in the last year. The survey results, when expanded to the region, indicate that about 27,600 single-family homes switched heating fuels from electricity to natural gas. This represents nearly 3 percent of the electrically heated single-family homes in the region. Of the region's electrically heated homes, 69 percent are in western Oregon and Washington, and that is where 77 percent of the reported conversions occurred. Conversion activity was significantly higher in investor-owned utility service areas than in publicly owned utility areas. Seventy percent of the conversions were in investor-owned utility areas, while only 47 percent of the electrically heated homes were located there.

The Council, helped by the Association of Northwest Gas Utilities and the Natural Gas Advisory Committee, collected information about fuel conversions from regional natural gas distribution companies. Although not all companies were able to provide data, the largest companies did. The data showed an active conversions market, but not quite to the level indicated by the Bonneville survey. For 1992, the gas utilities identified about 15,000 conversions of space heat from electricity to natural gas. In addition, there were about 19,000 water heater conversions, 7,000 of which were in homes already heated by gas. In total, gas utilities hooked up about 26,600 new customers as a result of fuel conversions in existing homes. Of these, 56 percent were from electric space heat, while the rest were primarily from oil heat with some propane and wood conversions. Generally, natural gas conversions in existing homes accounted for about half of all new gas hookups with the other half occurring in new construction. That is, natural gas companies are getting as many new customers from conversions as they are from new construction.

The surveys indicate that the regional fuel conversion market is very active. About 2 to 3 percent of electrically heated homes converted to natural gas in 1992, and similar levels of activity are evident since the late 1980s. For investor-owned utility service areas over 4 percent of electrically heated homes converted and over 6 percent of western Washington investor-owned utilities converted. Since gas is not available for many homes with electric heating, the shares of the eligible conversion market are considerably higher.

Fuel Choice and Conversions in the Council's Demand Forecast

One of the important elements in determining the electric savings from fuel conversion policies is the number of conversions that are expected to occur through market forces alone. A higher forecast of market-induced fuel conversions would lower the estimate of savings attributable to fuel conversion programs. Most of the studies of fuel conversion potential described earlier included an estimate of, or assumptions about, market-induced fuel conversions. For example, Bonneville's study assumed that homes with natural gas space heat and electric water heat would convert the water heat to gas without a utility program. Aos and Blackmon, in their study for Washington Natural Gas, used the forecasts of fuel conversions implicit in the Council's electricity demand forecasts. They estimated this number to be 44,000 electric space heaters and 180,000 electric water heaters. They used this number in their study in order to maintain consistency with the Council's power plan, but noted that recent experience in the Seattle area seemed to indicate that conversions were actually occurring at a faster rate.

Council staff calculated the implied conversion rates in its medium-high forecast and found the water heat conversions to be lower than Aos and Blackmon's estimate, at 105,900 water heaters. Space heat conversions were similar to Aos and Blackmon's estimate, at 47,500 space heaters. On average, over the 20-year forecast, this is about 2,400 space heaters a year and 5,000 water heaters a year. These levels are far below the recent activity described above. However, the forecasts do not estimate that conversions would occur uniformly in the future. The forecasts show greater conversion activity in the early years. For the 1990 to 1993 period, for example, the forecast conversions to natural gas from electricity are about 4,000 space heaters a year and 14,000 water heaters a year. These estimates of space heat conversions are still well below recent experience. Forecasts of water heat conversions are also below recent experience, but they are not nearly so far off.

The forecast model's fuel conversion predictions are sensitive to natural gas prices and energy-efficiency programs. For example, space heat conversions were about doubled in the medium-high forecast compared to the medium forecast which had lower natural gas prices. In the case of water heat, fuel conversions were sensitive to the presence of programs to improve the efficiency of water heaters and hot water use. With improved efficiency there are fewer conversions predicted because the amount of energy saved by conversion is reduced, making the investment less attractive.

Council staff also examined the behavior of the forecasting models in predicting new home space heating fuel choice. Bonneville's PNRES92 survey showed regional new home fuel choice for two intervals, 1986 to 1988 and 1989 to 1992. The electric heating share for homes of all types built between 1986 and 1988 was 58 percent, while the forecast model average for the same years was 55 percent. However, if the 1987 forecast, which is out of line with the surrounding years, is ignored, the average forecast of electric heating share was 58 percent, the same as the survey results. By the 1989 to 1992 period, the PNRES92 survey showed the new home electric space heat share to have fallen to 52 percent, while the forecasting model remained near 58 percent. For natural gas fuel choice the survey showed an increase in share between the two periods from 23 percent to 33 percent, while the forecast model predicted about 26 percent in both periods. Thus, while the general level of the forecasts is reasonable, there is concern about very recent trends not being reflected.

New home fuel choices combined with equipment conversions in existing homes result in a total share of homes in the region that heat with electricity. Table 2 compares fuel shares for all regional homes as reported in the 1990 Census with the model's forecast for fuel shares in 1990. The forecast model shares are reasonably close to the actual shares reported in the Census, although the electricity share is a little high and the natural gas share is a little low.

Table 2: Space Heating Fuel Shares, 1990

	Census	Medium Electricity Sales Forecast
Electricity	47.3	48.4
Natural Gas	26.3	23.9
Oil	9.8	11.8

In summary, the degree to which the forecasts are underpredicting the long-term number of fuel conversions depends on the degree to which strong conversion activity continues. It seems most likely that, although the conversion activity will probably slacken somewhat after a few years, the models are still predicting too few conversions over the long run. In other words, the market is likely to achieve more conversions than are reflected in the Council's 1991 power plan, and the potential savings from conversion programs will correspondingly diminish.

Analysis

Savings and Cost Estimates

After reviewing the various regional studies of fuel conversion costs and potential savings, the Council staff decided to undertake its own analysis. Although the previous regional studies were a useful starting point and provided much of the important data, there were some areas where refinement was needed. In particular, the analysis described below and in Appendix D more carefully defines the market segments and addresses the variation in important factors that determine cost-effectiveness.

The analysis is limited to existing single-family detached homes using conventional electric space or water heat. Thus, the study does not evaluate fuel choice in new homes, conversion in existing multifamily and manufactured housing or homes with heat pump systems. The-single family detached market is where most conversion activity has been observed and seems to hold the most promise for cost-effective fuel conversions. This part of the housing market contains 62 percent of the electric space heat, 75 percent of the electric water heat and 93 percent of the electric water heaters in homes with gas heating systems.[7] The limitation of the analysis to existing single-family detached homes is not intended to imply that there is no cost-effective conversion or fuel choice potential in the other housing markets. Council staff did not feel, however, that there was adequate data to quantify the potential in these other markets.

There are five specific market segments analyzed:

[7]Calculated from Residential Fuel Conversion Potential and Cost-Effectiveness: Portland General Electric Service Area, Steve Aos and Glenn Blackmon, July 15, 1992, p. 5.

1. Conversion of electric water heat to gas where gas is already used for space heating.
2. Conversion of an electric forced-air furnace and electric water heat to gas where only a gas service connection is required.
3. Conversion of an electric forced-air furnace and electric water heat to gas where both a gas main extension and a gas service connection are required.
4. Conversion of electric zonal space heat and electric water heat to gas where only a gas service connection is required.
5. Conversion of electric zonal space heat and electric water heat to gas where both a gas main extension and a gas service connection are required.

The analysis assumes that water heat will be converted at the same time that space heat is converted. This makes economic sense because it allows the main extension and service connection costs to be allocated jointly to space and water heat.

Studies of total energy efficiency have clearly shown that the most cost-effective fuel choice is very dependent on the specific conditions of the home. The most significant characteristic that affects the choice is the amount of energy used in the home. This depends directly on a number of factors including house size, thermal efficiency of the house and climate. The attractiveness of specific fuels also depends on energy prices and their expected escalation rates. In the case of conversion of existing heating to natural gas, the decision depends on the costs of conversion and getting gas service to the house. In spite of the fact that the effect of these conditions on cost-effectiveness is well understood, studies of fuel conversion potential and cost have relied on average assumptions to make their estimates.

The analysis for this paper has explicitly evaluated the range of conditions that exists for the important components of the cost-effectiveness determination. The analysis is based on distributions of house size, energy use for a given house size, conversion costs, main extensions and service connections. These distributions were based on data and estimates from various sources, as described in Appendix D. These distributions of energy use and conversion costs result in a distribution of costs per kilowatt-hour for electricity saved through conversion to natural gas.

The explicit evaluation of the variety of conditions that is expected to exist in the housing market provides two major enhancements to the estimates of potential cost-effective fuel conversion savings. First, it is possible to compare avoided alternative resource costs to the range of fuel conversion costs for a specific market segment. As a result, the analysis can identify the portion of the market segment that would be cost-effective to convert rather than accepting or rejecting the entire market segment based on its average cost. Second, it is possible to estimate the average cost of the cost-effective portion of the market segment, rather than assuming the average cost of the entire market segment.

Figure 6 illustrates the use of a cost distribution for one market segment. The average cost of this market segment is 40 mills per kilowatt-hour, but the costs range from 25 mills to 60 mills. The avoided cost is assumed to be 36 mills. The shaded area shows the portion of the market segment that is cost-effective. Thus, about 20 percent of the market segment in this example is cost-effective, and it has an average cost of 32 mills. In the next step of the analysis, which evaluates this resource as a potential component of the electric power system, 20 percent of the megawatts, costing 32 mills, would compete with other resources to earn a place in the regional electric power system.

Figure 6: Selecting the Cost-Effective Portion of a Market Segment.

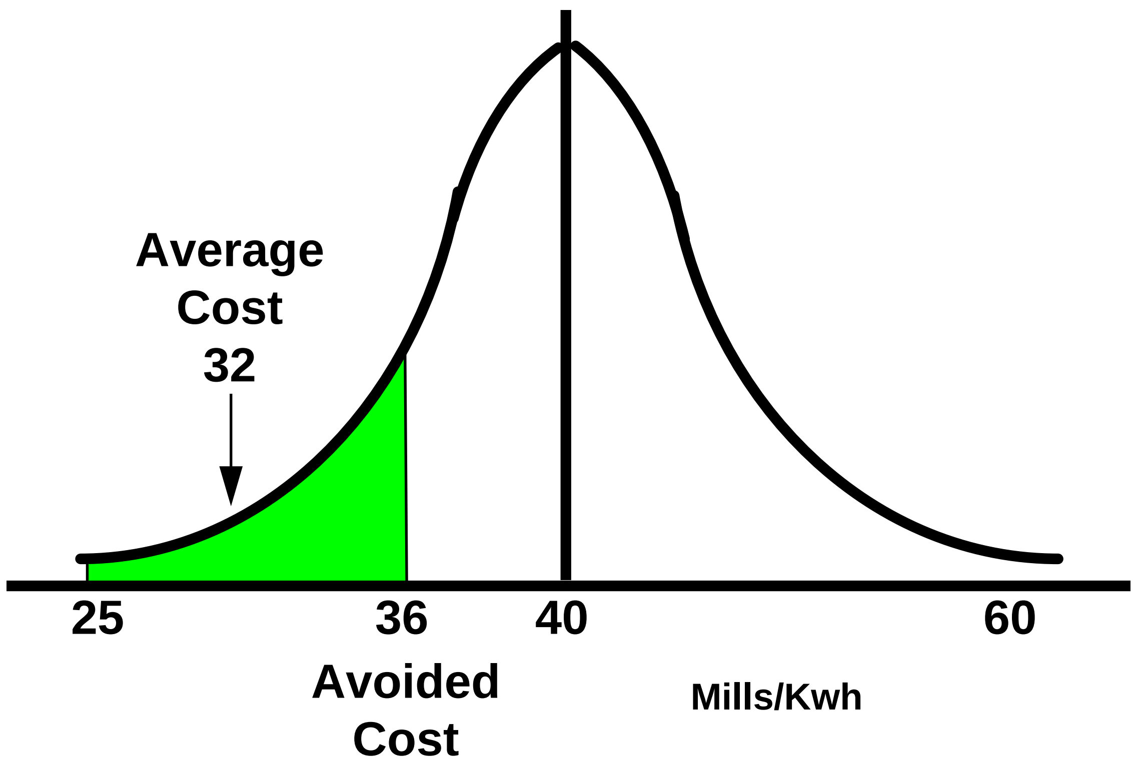


Table 3 shows the results of the analysis for each market segment. Three categories of megawatt savings are shown. "Technical potential" is the total megawatts of electricity use that could be avoided if all of the homes in the market segment that have gas available and are technically feasible to convert were converted to natural gas. It was assumed that 95 percent of segments one and two and 90 percent of the other three segments would be technically feasible to convert.

"Achievable economic potential" is the portion of the market segment's technical potential that is cost-effective, as shown in column two and illustrated in Figure 6. In addition, it was assumed that only 90 percent of the cost-effective potential could actually be achieved. The percent cost-effective in Table 3 refers to the percent of the <u>homes</u> where conversion is cost-effective. When converted to <u>average megawatts,</u> economic potential is not the same percentage of technical potential because the average electricity consumption avoided is higher for the cost-effective homes than for the average home in the segment.

"Resource potential" is the savings that could be achieved beyond what the market is expected to achieve. Since this involves the future, it is unknown, so a range is examined. The low market-induced conversions case is based on the Council demand forecasting model predictions of conversions, given the current lower gas price forecasts. Since recent conversion activity has been significantly above the model forecasts, the high market-induced case is provided as an alternative view of the future. It assumes that conversion activity is closer to recent experience over the forecast period; 67 percent of the cost-effective water heat conversions, and 71 percent of the cost-effective space heat conversions, are assumed to occur over the next 20 years.

Table 3: Fuel Conversion Supply Estimates

	Technical Potential (MWa)	Percent Cost Effective	Achievable Economic Potential (MWa)	Resource Potential		Average Cost (Mills/Kwh) (1990 dollars)	
				Low Mkt. (MWa)	High Mkt. (MWa)	Tech.	C/E
Water Heat Only	156	100.0%	140	119	46	22.1	22.1
Forced Air- Service	245	99.4%	220	94	9	23.6	23.5
Forced Air - Main	167	96.8%	148	71	19	25.9	25.5
Zonal - Service	347	33.7%	148	96	62	39.0	32.0
Zonal - Main	249	22.2%	77	51	34	42.3	32.4
Total	1,164		733	431	170	32.3	26.3

The analysis shows that there are 1,164 average megawatts of electricity that could be saved by using natural gas for space and water heat in the market segments considered. However, only 733 megawatts of these savings would be cost-effective and achievable. The market is likely to achieve between 302 and 563 megawatts of these savings, leaving between 431 and 170 megawatts as possible targets of some form of policy or program to encourage cost-effective fuel conversions.

The last two columns of Table 3 show the average total mills per kilowatt-hour resource cost in 1990 dollars. The next to last column, labeled "Tech.," is the average cost of the technical potential in each market segment. The last column, labeled "C/E," is the average cost of the cost-effective portion of the market segment. Thus, the average cost of the cost-effective fuel conversions is 26.3 mills per kilowatt-hour.

One interesting comparison to make is between the costs of fuel conversion and weatherization of single-family homes. The estimated costs of single-family home weatherization from the 1991 Power Plan is 32 mills per kilowatt-hour. While this is considerably above the 26 mill per kilowatt-hour average cost of the fuel conversion programs, it is roughly equivalent to the cost of the zonal-heated conversions. Since acquiring one resource (weatherization or fuel conversion) has ramifications for acquisition of the other, it raises the policy question of when to pursue fuel switching over weatherization.

This analysis assumes that those homes where gas is not available are available for full weatherization. The rest of the stock is tested for fuel switching, and if cost-effective, is converted with the remainder available for full weatherization. However, had the analysis been reversed, as was suggested by some commentors, i.e. full weatherization of the stock before analysis of fuel conversion, the results would be significantly different. For example, application of weatherization to the zonal-heated stock would have pushed the entire stock out of the range of cost-effective fuel conversions.

For a number of reasons, it would be inappropriate for the analysis to have proceeded in the latter direction. First, the goal of the analysis was to examine the minimum life-cycle cost to the region, including electric and gas supply-side resources. If, as in the zonal heated case, weatherization and fuel switching are the same cost per saved kilowatt-hour but are mutually exclusive resources, the region would be best served by selecting the largest of the two options, since that would mean less purchase of the next more expensive resource up the cost-supply curve.[8]

Second, the fuel conversion cannot be analyzed as if it were an incremental measure in the efficiency supply curve because it represents a discontinuity in the supply curve. For example, if all regionally cost-effective weatherization measures up to the average cost of fuel conversion are applied first, the fraction of the stock that can be cost-effectively fuel switched is reduced because of the reduced energy usage. If however, fuel switching is applied first, there may still be cost-effective weatherization measures to apply, albeit a reduced amount given the avoided cost of gas. The optimal choice would consist of the package of fuel switching and efficiency that minimizes total societal costs, including replacement electricity generating and gas resources. The analysis presented in this paper stops short of analyzing cost-effective levels of weatherization in converted houses. Since these measures would only be applied if they lowered regional cost, inclusion of this effect would increase the cost-effectiveness of fuel conversions.

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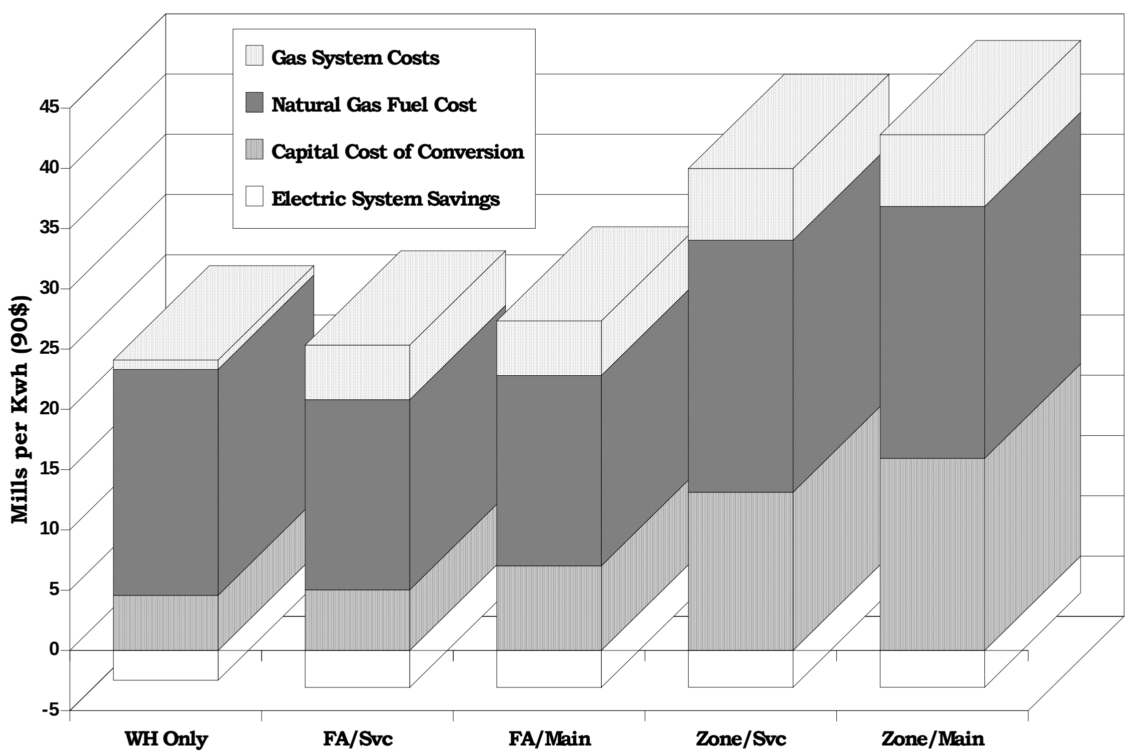
[8] For example, if the average zonal-heated house used 10,000 kilowatt-hour, the weatherization savings could be as large as 3,000 kilowatt-hours and cost the same as fuel conversion at 32 mills per kilowatt-hour. If the remaining 7,000 kilowatt-hours of electric usage in the post weatherized house were provided by a combustion turbine at 35 mills per kilowatt-hour, then the true cost of the weatherization choice would be 34 mills per kilowatt-hour compared to acquiring all 10,000 kilowatt-hours at 32 mills per kilowatt-hour through fuel conversion.

An important finding of this analysis relates to the composition of the fuel conversion costs. Figure 7 shows the major components of the costs. A significant share of the costs of fuel conversion is the gas costs to be paid by the user over the life of the analysis. This share varies from 53 percent of the costs for the "zonal-with-main-extension" segment to 87 percent for the "water-heater-only" segment. The capital cost of the equipment conversion and the gas hookup is only between 21 percent and 40 percent of the total costs. In the case of weatherization programs, capital costs are the entire cost. Thinking in terms of the investment that would be required to cause fuel conversions to happen, the costs are very low, ranging from about 5 to 16 mills per kilowatt-hour, much of which may be offset by reduced electrical transmission capacity costs.

Figure 7: Fuel Conversion Cost Components



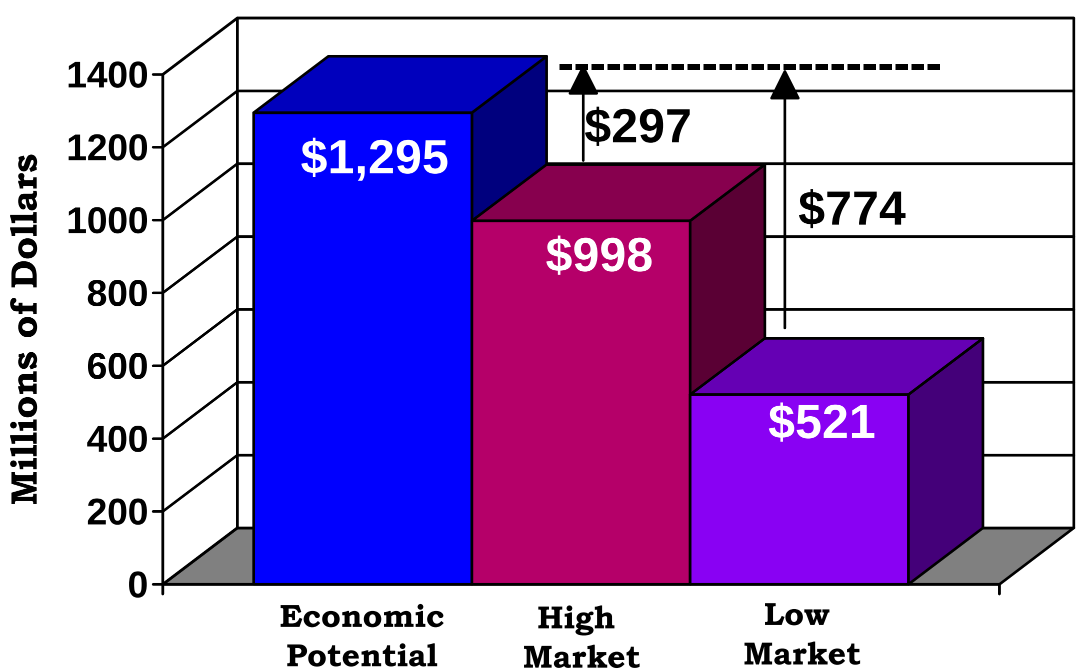
System Analysis

Once the initial estimate of cost-effective fuel conversion potential is developed, it can be evaluated within the regional power system planning framework. This provides a more direct comparison of fuel conversions with other resources available for meeting future electricity needs. The Council's principal planning model, ISAAC, provides an estimate of the value of fuel conversions in terms of changes in net present value of system costs that result from substituting fuel conversions for alternative resources in the Council's resource portfolio. By explicit incorporation of uncertainty about future electricity demand growth and natural gas prices, ISAAC provides information about the sensitivity of the value of fuel conversions under different demand growth rates and different natural gas price escalation assumptions.

Two important enhancements of ISAAC, since the 1991 Power Plan, facilitate the analysis of fuel conversions. The first includes, in the system cost calculations, an estimate of the costs of natural gas burned directly in homes as a result of fuel conversions. The second permits an analysis of the environmental emissions associated with different resource strategies. This capability includes the ability to assess the pollutants associated with direct use of gas along with other electricity resources.

Figure 8 shows the value of fuel conversions to the power system. Three cases are shown. The first, labeled economic potential, shows the change in net present value of system costs that would result from making all of the cost-effective fuel conversion potential available as a power system resource. This would decrease the cost of the power system by $1,295 million over time. This analysis did not include an administrative cost to achieve this level of conversions. It only answers the question, if all cost-effective conversions were available, how much would they be worth?

Figure 8: Benefits of Fuel Conversions.



In all likelihood, some portion of the cost-effective conversions will occur as market-induced actions. As noted above, the amount of these market-induced conversions is unknown. The high and low-market conversion cases described in Table 3 would provide different levels of benefit to the power system if they occurred. Figure 8 shows the value to the power system of the high-market and low-market cases. High-market conversions, similar to recent experience, would reduce power system costs by $998 million, achieving a substantial portion of the possible benefits from cost-effective fuel conversions and leaving only $300 million as a potential benefit from policies and programs to encourage further conversions. Low-market conversions, however, would achieve only $521 million of the benefits leaving close to $800 million to be achieved through policies or programs.

In summary, the need for and value of actions to encourage fuel conversions is highly dependent on what the market is likely to achieve without any intervention. Unlike the case of electricity efficiency, there is considerable evidence that the fuel conversion market may achieve a substantial portion of the potential saving over time. If this is the case, programs may just accelerate the conversions that would happen eventually anyway. Preliminary Council staff analysis showed that there would be relatively little value associated with accelerating the pace of conversions if they were likely to be achieved by the market. This implies that one option would be to wait and see what the market is achieving while trying to improve the incentives and remove disincentives for fuel conversions. This approach would require some improved data collection on conversions in order to better evaluate the pace of conversion.

ISAAC studies also permit an evaluation of total natural gas requirements for the combined electrical system and direct gas use due to conversions. The analysis presented here assumed that a large share of the new resources, available and cost-effective to meet future electricity needs, would be electricity conservation or gas-fired generation. The total amount of natural gas projected to be used by the electric power system by 2013 is 263 trillion Btu per year in the absence of fuel conversions. This includes gas burned by nearly 5,000 megawatts of both existing and new combustion turbines. For comparison, the total natural gas consumption in the region in 1992 was 400 trillion Btu. Thus, with expected load growth and strong reliance on gas-fired combustion turbines, current gas use in the region could be increased by nearly 66 percent over recent levels. This represents a 2.6 percent a year growth in regional gas use.

Fuel conversions displace mainly gas-fired generation. However, since there are only 733 megawatts of cost-effective conversions, and each of those conversions only saves 20 percent of the gas that would be required if electricity were used instead, the effect of fuel conversions on total gas use is fairly small. Doing all cost-effective fuel conversion is estimated to reduce natural gas use by only 6 to 8 trillion Btu per year by 2010.

Some commentors on the draft issue paper noted the large discrepancy between the estimated 20 percent gas savings above and the 30 to 50 percent savings shown in Figure 1. (If the savings in Figure 1 are weighted by the potential conversions in each market segment, the average savings are 34 percent.) The two numbers are very different. The ISAAC analysis reflects displacement of a number of power system resources by fuel conversions, not just combustion turbines. For example, residential weatherization programs are partially displaced by conversions. In addition, when combustion turbines are displaced, the fuel savings reflect the fact that these plants are backed down by secondary hydroelectricity some of the time, thus reducing the gas savings.

The ISAAC model studies shed some light on other issues, including the sensitivity of the results to changes in natural gas prices and the environmental impacts of fuel conversion. In the case of gas prices, the analysis shows that the benefits of fuel conversion are relatively insensitive to different fuel price assumptions. This is because most alternatives to direct gas use involve using gas to generate electricity. Since electricity generation uses a little more gas, the value of fuel conversions increases slightly with higher gas price escalation. If the alternative resource to direct gas use were electricity conservation or renewable energy, the value of fuel conversions would be much more sensitive to gas price assumptions.

The environmental effects of direct use of natural gas, compared to electricity generation, are mixed. There are three main influences to consider: first, the relative amount of gas required; second, the amount of pollutants emitted per Btu of gas burned and third, the interactive effects with the rest of the power system. The environmental effects of fuel conversions are discussed in appendix D and are only summarized here.

In the case of nitrous oxide and carbon monoxide, total pollutants are increased with direct gas use. This is because the emission factors are larger for end-use furnaces and water heaters than for a combustion turbine. The emissions are enough larger for direct use of gas that the lower total gas requirements are more than offset. Carbon dioxide, in contrast, is reduced significantly by fuel conversion because the emission factors are the same for direct use as for combustion turbines. Since total gas use is reduced by fuel conversions, the amount of $CO2$ released is also reduced.

Sulfer oxide shows a significant decrease with fuel conversions. This is due to the seasonal pattern of the savings in electricity use, which result in occasional displacement of existing coal-fired generation. The reduction in sulfer oxide is due to reduced use of these coal-fired units. The effects on suspended particulates and volatile organic chemicals were found to be insignificant.

Council Policy

The reduced price outlook for natural gas and the improved technology of gas-fired electricity generation have made gas-fired base-load generation cost-effective. This development raises anew fuel choice and fuel conversions as a policy issue for the Council. Past Council policies regarding fuel conversions and fuel choice were summarized in an earlier section and are described in Appendix A. To briefly recap, the Council has not included fuel conversion actions in its previous plans. The Council has stated that it does not consider fuel conversions to be conservation, but that electricity efficiency programs should be monitored to ensure that they do not affect fuel choice by discouraging the use of natural gas where it is available, energy efficient and cost-effective.

Public comment on the draft of this issue paper supported the need for the Council to increase its consideration of direct use of gas in its power planning. However, there was little support for treating conversions as a resource to be acquired and paid by electric utilities. Based on the issue paper, public comment and consultations with gas industry representatives the Council adopted the following policy statement to guide staff analysis for the 1995 power plan.

Council Policy Statement

The Council recognizes that there are applications in which it is more energy efficient to use natural gas directly than to generate electricity from natural gas and then use the electricity in the end-use application. The Council also recognizes that in many cases the direct use of natural gas can be more economically efficient. These potentially cost-effective reductions in electricity use, while not defined as conservation in the sense the Council uses the term, are nevertheless alternatives to be considered in planning for future electricity requirements.

The changing nature of energy markets, the substantial benefits that can accrue from healthy competition among natural gas, electricity and other fuels and the desire to preserve individual energy source choices -- all support the Council taking a market-oriented approach to encouraging efficient fuel decisions in the region.

The following examples illustrate the market-oriented approaches to encouraging cost-effective fuel choices:

(1) Providing information in the power plan on the cost-effectiveness of direct natural gas use along with the resources in the power plan resource portfolio.

This will include identification of possible synergy between fish and wildlife flows and the pattern of demand reductions from fuel conversions.

(2) Encouraging efficient pricing of energy so that consumers can see the true value of alternative choices.

(3) Working with electric utilities, public utility commissions and others to ensure that policies on system expansion and new service connections, advertising, electric efficiency incentives, zoning practices, building codes and other policies do not unnecessarily distort consumer decisions about energy choices.

(4) Continuing the role of the Natural Gas Advisory Committee as a forum for coordination and discussion of issues that affect both gas and electric industries.

(5) Council staff participating in least-cost planning efforts of both gas and electric utilities, possibly encouraging utilities to consider direct use of gas as an alternative in their own least-cost plans.

Appendix A

Past Council Analyses and Positions

The Council has not taken a strong position to encourage particular fuel choices in its past power plans. However, the issues of fuel switching and fuel choice have been thoroughly examined and considered in developing the plans.

SRC Study, 1982

The Council contracted with Synergic Resources Corporation (SRC) during the development of the first power plan to examine potential reductions of electricity use in the Pacific Northwest through increased use of alternative fuels. The SRC study, completed in September 1982, is probably the most comprehensive study of fuel switching and choice potential that has been done for this region. It looked at the residential, commercial and industrial sectors and estimated potential conversions for both private and public utility service areas. The data for the residential study was built from county-level data, and 21 combinations of equipment, fuel and housing characteristics were evaluated.

The SRC study identified 3,655 average megawatts of potential fuel switching by the year 2000, primarily in the residential sector. This was estimated to add 1,610 million therms to regional natural gas demand. Too many conditions have changed since the SRC study was done to make the numerical results applicable in today's market. However, the study addressed several issues that are still keys to the debate.

The SRC study explored the effects that electric efficiency incentives might have on fuel choice. For example, incentives paid to improve the efficiency of electrically heated homes can cause more such homes to be built. This is because the cost of the improved efficiency would be partly paid by the utility while the consumer receives a lower cost of heating. This makes the electrically heated house economically more attractive to the consumer. The increased choice of electric heating would thus offset some of the anticipated electricity savings from such a program.

Another important finding of the SRC study was that it generally is more cost-effective to weatherize a home and maintain its current heating system than to convert to a different fuel. This result has appeared in several subsequent studies and is an important consideration in the debate about policies to encourage fuel conversions.

The SRC study established the link between historical fuel price patterns, the cost of heating and the choice of fuels historically. It was clear from the SRC results that markets have responded significantly to changes in relative costs of heating. The efficiency with which fuel markets work is an important consideration when assessing the need for total energy-efficiency policies and is discussed later in this paper.

Staff Issue Paper, 1982

The Council staff developed an issue paper in late 1982 to help the Council decide on the role that total energy-efficiency policies might play in the first regional Power Plan. With respect to fuel conversions in existing applications, the issue paper was concerned with whether to offer incentives for electric heating customers to convert to gas. The finding was that conservation was likely to be more cost-effective than fuel conversion. Hesitancy to encourage natural gas conversions was linked to concerns about future conversions of those inefficient homes back to electricity. The cost of natural gas was higher then. In addition, the outlook for natural gas price escalation was considerably higher and was viewed as even more uncertain than it is now. The Council was reluctant to encourage consumers to shift to natural gas when it could subsequently turn out to be a very expensive choice.

The discussion of fuel choice for new homes centered around whether efficiency standards and incentives should apply to both electric and gas-heated homes. There was concern about affecting the fuel choice of consumers and the possibility that inefficient gas-heated homes could switch to electricity in the future. In addition, the Council heard comment that having multiple code levels for new construction would be administratively complex and costly. Natural gas as an electricity generating resource did not look particularly attractive at the time and was a further argument against promoting the end-use of natural gas instead of electricity.

The staff issue paper recommended that Council policy should neither encourage nor discourage particular fuel uses and that new energy-efficiency codes be applied equally to all new construction, regardless of heating fuel. It was decided that direct end-use of natural gas was not conservation, but rather a fourth priority (non-renewable) resource under the Act. The reluctance to encourage use of natural gas was related to the perception that future gas prices and availability were highly uncertain. In addition, it appeared that conservation was both cheaper and a higher priority resource under the Act. Since base-load natural gas generation was not expected to be a cost-effective resource in the plan and was, in fact, prohibited under the Power plant and Industrial Fuel Use Act, the thermodynamic-efficiency argument was not applicable. The decision about whether to give incentives for use of natural gas in new homes could be delayed.

1983 and 1986 Power Plans

In the 1983 Power Plan, the Council stated that "conservation involves the more efficient use of electricity."[9] The Council's policy on fuel switching in the 1983 Power Plan was neither to encourage nor discourage a consumer's continued use of electricity instead of a nonrenewable fuel. Since there was no evidence of fuel switching to electricity, the Council deferred applying efficiency incentives to all homes regardless of heating fuel choice. However, the 1983 plan did include a fuel conversion efficiency standard for homes that switch from natural gas to electricity.[10]

In settlement of a legal challenge to the 1983 Power Plan, the Council agreed that, if substantial fuel switching, as a result of the plan, were documented and made the plan not cost-effective, it would take action to limit further switching. Further, the Council agreed to clarify that the model conservation standards apply only to electrically heated homes.

The 1986 Power Plan did not change the Council conclusions on fuel choice. The 1986 plan did, however, contain two action items relating to fuel choice. The first called for Bonneville to develop and implement a method for monitoring the effects of incentives on the choice of heating systems by new home buyers. The second committed the Council to analyzing the costs of heating new homes with electricity and natural gas.[11]

Council Cost of Heating Study

In response to both the action item described above in the 1986 plan and to questions arising from the code adoption process, the Council did a study of the cost of heating new homes.[12] The study focused only on space heating in new homes but considered an array of heating systems, fuel types and building shell efficiency levels. Considering three different house sizes, the study evaluated costs from four perspectives: first cost, annual energy costs, annual after-tax cost of heating and heating system life cycle costs. The study did not include the cost of gas service connections or main extension costs, factors that have been considered important in subsequent studies.

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[9] 1983 Northwest Conservation and Electric Power Plan, Volume I, Page 7-1.

[10] 1983 Northwest Conservation and Electric Power Plan, Volume I, Page 10-11.

[11] 1986 Northwest Conservation and Electric Power Plan, Volume I, Page 9-8.

[12] Heating New Homes: A Comparison of the Cost of Heating with Electric, Natural Gas and Fuel Oil Heating Systems, Northwest Power Planning Council, Publication 88-11, June 22, 1988.

The conclusions varied widely depending on house efficiency levels, relative fuel costs, heating system, presence of air conditioning, climate zone and house configuration. Therefore, generalization from the results is very difficult. The clearest conclusion is that most of the options widely available and used in the market today can be competitive in some conditions. The overall costs of alternative options are sensitive to first costs, system efficiency and shell efficiency.

The study clearly illustrated that simple energy-efficiency arguments or fuel price comparisons are inadequate to draw conclusions about the cost-effectiveness of heating with different fuels. For example, zonal electric heating systems in homes built to the model conservation standards in the 1986 plan were found to cost less than natural gas heating systems built to then current codes under current prices by most measures and in most climate zones. The finding reflects the low first cost of zonal electric heating systems, their low maintenance cost and the high efficiency of the system with no conversion losses or duct and flue losses. However, in comparing gas and electric forced-air systems, the costs were very close at then current relative prices. In general, zonal systems were found to cost less than forced-air systems, but the zonal advantage was less clear in a house with the furnace and ductwork in the heated space.

The study showed that one effect of building homes with higher thermal integrity is to significantly reduce the effect of price escalation on the cost of heating. Thus, thermal integrity of the house shell serves as a risk mitigation against fuel price uncertainty.

1991 Power Plan

The 1991 Power Plan did not contain a substantial change in the Council's policy of fuel choice or fuel switching. However, in response to falling natural gas prices, the role of natural gas for electricity generation in the Power Plan increased. The uses of natural gas were limited to cogeneration and hydro-firming combustion turbines. This increased use of natural gas did cause the Council some concern for total energy efficiency. As a result, the Council expressed a strong preference for "thermally balanced" cogeneration. This is viewed as a high-efficiency resource. Cogeneration that is primarily just a large electricity generating plant with insignificant thermal loads would raise issues of total fuel efficiency.

In recognition of the likelihood of growing reliance on gas-fired generation, the Council called for the formation of a natural gas policy group to explore issues of coordination between the natural gas and electric industries.[13] That group has met and started the process of increasing mutual understanding between the two energy industries.

[13] 1991 Northwest Conservation and Electric Power Plan, Volume I, page 47.

Appendix B

Regional Analyses of Direct Gas Use

Several studies have been done by organizations and individuals in the region addressing the issues of fuel conversions and fuel choice. These studies have various scopes, address different regional areas and focus on different sectors and end-uses. However, it is useful to break these studies into two general types. One type focuses on the cost-effectiveness of alternative fuel choices and efficiency levels in new buildings, and the second type focuses on determining fuel conversion potential in existing buildings. The former has been done primarily in support of the development of building efficiency codes in Oregon and Washington. This section reviews the available studies and summarizes some of the findings.

New Home Energy-Efficiency Studies

The Council's cost of heating study, which was discussed in the previous section, is an example of a new home energy-efficiency study. Similar studies were done by the Washington State Energy Office[14] and Oregon's Energy Conservation Board[15] in support of legislative consideration of building-efficiency codes.

Oregon Energy Conservation Board

The Oregon study was done by a Technical Working Group appointed by the Energy Conservation Board. The Technical Working Group consisted of representatives of several organizations, including the Council staff. The analysis was done using an engineering model of home energy use called SUNDAY, supplemented by some other analyses and models. A number of structural efficiency measures were examined for several representative building types, heating systems and climate zones. The analysis sought the set of efficiency measures that was most cost-effective to the house occupant.

The Oregon study plotted the life-cycle costs of the heating plant, conservation measures and fuels. The objective was to identify those measures to include in a residential energy-efficiency code that would minimize the life-cycle costs. Perhaps the most significant finding was that the life-cycle costs were minimized

[14] Analysis of Consumer and Marginal Costs for Electric and Natural Gas Space and Water Heat in Single Family Residences in Puget Sound Power and Light Company Service Territory, Dick Byers, Washington State Energy Office, September 1989.
[15] Oregon Residential Energy Efficiency Project, June 1990.

with the same efficiency measures for zonal electric, gas forced-air and electric forced-air systems. In the case of heat pumps only a couple of measures were found to be cost-effective, but life-cycle costs of the heat pump system were also the highest of the four systems examined. The findings of this study accounted in part for Oregon adopting a single code for all homes regardless of the energy source used for heating.

The Oregon study also showed that the life-cycle costs of zonal electric heating systems were the lowest, followed by gas forced-air and then electric forced-air. These results were based on costs to the consumer rather than to society. Therefore, electricity and gas fuel costs were average costs rather than incremental costs as would have been used for a study from a societal perspective. The study included forecasts of fuel price escalation in which natural gas prices are expected to grow faster than electricity prices, and these assumptions had significant effects on life-cycle costs.

Washington State Energy Office

The Washington State Energy Office study was focused on the relative cost of space and water heating using natural gas or electricity. Its calculations were based on typical energy consumption levels in houses rather than an energy engineering simulation model. The study looked at total cost of space and water heating from three perspectives for both new and existing homes--that of the consumer (as in the Oregon study), society and the utility. Unlike the Oregon study, this one assumed that current energy prices escalate with inflation, but not in real terms.

The results for relative costs in new homes were different from the Oregon findings. The lowest cost option from the consumer perspective was natural gas space and water heating in a home built to the 1986 Washington State Energy Code. Using natural gas and building the home to the higher efficiency levels in the Council's model conservation standards (MCS) resulted in higher costs. The least expensive electric heating option for the homeowner is resistance zone heating built to the Council's model conservation standards. The difference from the Oregon results may partly reflect historically higher residential gas prices in Oregon.

The study found that if natural gas price escalated at 2.5 to 2.8 percent per year above inflation, then the advantage of natural gas would disappear. For comparison the Council report (93-4) on Natural Gas Supply and Price projected residential gas prices to increase between -.5 percent and 1.9 percent annually.[16]

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[16]Natural Gas Supply and Price, Northwest Power Planning Council, draft staff issue paper 93-4, March 12, 1993.

The findings on relative costs for new homes were true from a societal perspective as well. Generally, gas is least expensive in homes built to the 1986 Washington State Energy Code levels. Electric resistance heat is the lowest cost electric option, and it has the lowest cost at the higher MCS efficiency level. Electric heat pumps were the most expensive option. The findings of this study partly supported the use of different code levels in Washington for gas and electric heated homes.

In existing homes that are already heated with natural gas, the WSEO study shows large cost advantages to heating water with natural gas. This advantage would not be eliminated by most current forecasts of natural gas price escalation. It is also true from any of the three perspectives tested.

Fuel Conversion Potential Studies

A number of studies have been done over the last few years that address the potential electricity savings that could be achieved from programs to convert electric space and water heat to natural gas. The Council study, done by SRC, was an early forerunner of these studies. More recent studies have been done by or for state energy offices and individual electric and gas utilities. As a general rule, these studies begin with estimates of the number of residences having electric space or water heat. Potential fuel conversion savings are then calculated along with the costs of conversion under different gas availability assumptions. Technical potential estimates are modified to account for cost-effectiveness and for portions of the potential likely to be accomplished by market forces alone.

<u>Association of Northwest Gas Utilities</u>

Pacific Energy Systems, Inc. did a study for the Association of Northwest Gas Utilities in 1990.[17] The study explored the benefits that might be gained through coordinated energy planning. The study focused on energy efficiency rather than economic efficiency and was limited to water heat and cogeneration.

The study compared the gas required to provide an equal amount of hot water from an electric water heater using electricity generated from hydro-firming combustion turbines and from a gas water heater. When the natural gas displaced in California by secondary hydroelectricity was considered, the total gas required for the electric water heater was 42 million cubic feet compared to 25 million cubic feet for a gas-fired water heater. The study also looked at the environmental effects of using natural gas and electricity for water heating.

[17]<u>Coordinated Energy Development in the Pacific Northwest</u>, Pacific Energy Systems, Inc., April 12, 1990.

The study calculated that if one million water heaters were converted from electricity to natural gas, the region would save 530 average megawatts of electricity. The study showed that the rate of return on a consumer's investment in conversion from electric to natural gas water heat would be sensitive to a number of factors, including electricity price, water heater efficiencies, hot water consumption and whether the old water heater needed replacement or not.

In addition, Jim Lazar did a reconnaissance-level evaluation of fuel switching potential for the Association of Northwest Gas Utilities in 1990. His study included both space and water heating. The results of his study were presented to the Council during the development of the 1991 Power Plan. Lazar identified fuel conversion potential of 1,448 average megawatts in the existing single-family residential sector. Table B-1 shows a breakdown of the estimated potential and its costs which are expressed in levelized nominal dollars from 1990 forward.

Table B-1: Fuel Conversion Potential from the Lazar Study.

Conversion	Potential Conversions	Potential Savings (MWa)	Average Costs (Mills/kWh)
To gas water heat in home with existing gas space heat	350,000	198	39.4
To gas space and water heat with service connection only	200,000	357	59.0
To gas space and water heat with line extension and service connection required	500,000	893	64.1

ODOE/OPUC

In the Fall of 1991 the Oregon Department of Energy and the Oregon Public Utility Commission staffs did a study of the cost-effectiveness of fuel conversions for a limited set of circumstances. The study addressed single-family houses for two possible conversions: to gas water heat when natural gas is already in the home and from an electric forced-air furnace to a gas furnace where gas is readily available at the street. This study did not attempt to estimate the potential electricity savings possible through fuel conversions, but rather focused on cost-effectiveness under alternative usage levels, prices and equipment efficiencies. The study evaluated cost-effectiveness from both the consumer and societal perspectives.

There were many cases where fuel conversions were found to be cost-effective from either the consumer or societal perspective. Conversion became less cost-effective with declining usage levels. Therefore implementation of conservation measures tended to reduce the cost-effectiveness of fuel conversions. The avoided costs from the societal perspective made some conversions more cost-effective for society or a utility than for consumers. Because of the diversity of results for different situations, a blanket fuel conversion policy was not recommended. Instead, the Oregon Public Utility Commission proposed a policy of considering specific policies proposed by the utilities. Utilities were asked to consider fuel conversion programs in their integrated resource plans. A set of tests for an acceptable fuel conversion program was developed that recognized the diversity of conditions that exist.

Pacific Power and Light (PP&L)

In commenting on the ODOE/OPUC study, PP&L did a parallel analysis of the cost-effectiveness of fuel switching.[18] In contrast to the ODOE/OPUC study, PP&L concluded that fuel switching is not cost-effective for any of the situations evaluated in the ODOE/OPUC study.

The different results were due to a number of assumptions. PP&L assumed much lower typical usage levels for electric space and water heat than the ODOE/OPUC study. In addition, PP&L assumed that efficiency improvements should be done before evaluating the cost-effectiveness of fuel switching. This further lowered the consumption levels for electric space and water heating, making the fuel conversion less cost-effective. PP&L also used different assumptions regarding avoided costs of natural gas, the risk associated with gas price uncertainty and the analysis of heat pumps.

Bonneville Power Administration

In the winter of 1991/1992 Bonneville Power Administration did a regional estimate of potential electricity savings from fuel conversion policies.[19] This study estimated housing stock and natural gas availability on a county level. The study only addressed the single-family and manufactured housing sectors, but did deal with both existing and new homes. In addition, the analysis addressed public utility service areas separately from investor-owned utility service areas.

There were some significant differences in the use of electricity between public utility and investor-owned utility service areas. The difference is most marked in

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[18]Technical Comments on Oregon Department of Energy and Oregon Public Utility Commission Fuel Switching Memo, Pacific Power and Light.
[19]Draft 1992 Resource Program, Technical Report, pages 141-149.

space heating. In public utility service areas, 53 percent of single-family houses heat with electricity compared to 28 percent in private utility service areas. Water heat shares are both higher and less different between service areas, 85 percent electric for public utilities and 75 percent for investor-owned utilities. This implies a significant number of households that have natural gas in the home but still heat water with electricity. Manufactured housing had high shares of electricity, although the difference between public and private utility areas is still evident.

The Bonneville study did not estimate the technical potential for fuel conversions but limited the applications considered by judging cost-effectiveness and what the market was likely to achieve without programmatic assistance. The estimated fuel conversion savings, therefore, excluded consideration of some of the most cost-effective opportunities. For example, houses with gas space heat but electric water heat were excluded on the assumption that these conversions would be done by the market. In addition, houses with resistance zone electric heating systems were excluded from the potential on the assumption that such conversions would not be cost-effective. New homes that are built within one quarter of a mile of an existing service main were assumed to chose gas space and water heat without any utility programs to encourage such choices. The Bonneville estimate also assumes there would be only a 70 percent participation rate in any programs that attempt to acquire fuel conversion savings.

The total number of households that were assumed to participate in a fuel conversion program by 2010 was 400,000. Comparison of this number with the 1,050,000 households used in Lazar's study illustrates how different estimates come about. Lazar's estimate is based on households now in existence. Bonneville's study starts from current households but builds the estimate over time, discarding old houses and building new ones. But most of the difference reflects the limits Bonneville placed on its eligible households for cost-effectiveness, program penetration limits and market-induced occurrence reasons. It is estimated that such exclusions from the Bonneville study may have decreased the resulting savings by about 725 average megawatts.

Potential electricity savings that could be achieved through fuel conversion programs were estimated at 385 average megawatts. The 385 average megawatts were divided between 33 average megawatts in new homes and the rest in existing homes. The average cost of the electricity savings varied from 15 to 39 mills per kilowatt-hour (real 1990$).

<u>Aos and Blackmon</u>

A study of regional natural gas conversion potential by Steve Aos and Glen Blackmon is the most recent and probably the most thorough.[20] The study was sponsored by Washington Natural Gas as part of the Washington State Energy Strategy development. This study is particularly relevant for the Council because it was designed to be an extension of the Council's plan to consider fuel conversion as a resource for meeting electricity needs. As such, the study used assumptions consistent with those in the Council's power plan to the extent possible. The study is limited to existing residential homes, but does include single-family, multi-family and manufactured housing.

Aos and Blackmon estimate that 3,020 average megawatts of electricity are consumed for space and water heat in the region -- 1,671 for space heat and 1,329 for water heat. Due to the historically low cost of electricity in the region, there is substantially greater use per household than is typical for the rest of the country. If the Northwest were to conform to the pattern of the country, 1,483 megawatts of electricity would be saved. Aos and Blackmon use this figure as the technical potential for the region.

Aos and Blackmon develop a supply curve for fuel conversion savings. It is based on market segments typical of fuel conversion studies and shows the megawatts of savings available at different costs. The market segments are based on three housing types, three gas availability categories and three equipment conversions. These categories are shown below and result in 21 segments for the supply curve:

Fuel Conversion Supply Segments

- Building Type:
  - Single-family
  - Multi-family
  - Manufactured
- Gas Availability:
  - In Home
  - Service Connection Required
  - Main Extension Required
- Equipment Converted:
  - Electric Water Heat
  - Central Forced-Air Electric Furnace
  - Zone Electric Heat

[20] Natural Gas End-Use Conversion As An Electric Power Resource: An Estimate of Potential and Cost in the Pacific Northwest, Steve Aos and Glen Blackmon, June 1992.

Cutting off the supply curve at the Council's avoided cost of 77 mills per kilowatt-hour eliminated 445 average megawatts of the technical potential, leaving 1,038 average megawatts of cost-effective savings. This estimate is further reduced by the amount of fuel conversion they estimated to have been included in the Council's forecast of electricity demand -- 193 average megawatts. The result is a regional fuel conversion resource estimate of 845 average megawatts.

WSEO

Dick Byers of the Washington State Energy Office did a study of fuel conversion potential in May 1992.[21] This study was done as a review of the draft study of fuel conversion potential by Steve Aos and Glen Blackmon. The Byers study reviews, and in several cases develops revised estimates of, the technical assumptions about fuel conversion costs and savings for various conversion situations. It also suggested additions to the Aos and Blackmon study that included differential operation and maintenance costs for gas and electric systems, incremental billing costs, transmission and distribution cost savings of the electric system and additional electric fan loads associated with a shift from zonal electric to a gas forced-air furnace.

The Byers study concluded that there was a technical potential for 1370 average megawatts of fuel conversion savings in the region for single-family existing homes. Of that number, 855 average megawatts were estimated to be cost-effective at the 77 mills per kilowatt-hour cutoff (levelized nominal from 1990 forward) used by the Council in its regional plan. If a higher cutoff of 83 mills (reflecting Puget Power's avoided costs which consider capacity costs appropriate for residential space and water heating load factors) were applied, the cost-effective savings increase to 1,177 average megawatts. After accounting for market-induced conversions as forecast by the Council and assuming an 85 percent penetration rate, Byers derives potential fuel conversion program savings from 460 to 730 average megawatts for single-family homes.

The market segments that were least cost-effective were electric zone heated houses. If gas is available at the street and only a service connection is required, it is cost-effective to convert to gas if the house is unweatherized. If the house is weatherized, however, the conversion is only cost-effective at the higher cutoff level. In either case, the benefit cost ratio to the consumer is less than one. If an extension of the gas main is required, the only conversion from zone electric that is cost-effective is for an unweatherized house at the higher cutoff level.

Byers extended the draft Aos and Blackmon study to look at new construction in Washington. The electricity savings were not presented for new houses, rather the study provided three measures of effects: consumer benefit cost ratios, dollars

[21]Letter from Dick Byers to Steve Aos and Glen Blackmon, May 5, 1992.

per kilowatt-hour and net therms of natural gas saved per year compared to generating electricity with a combustion turbine. Generally, direct use of natural gas appeared to be cost-effective and reduced the total use of natural gas. However, there was an important exception to this rule. A house with zonal electric heating, built to the 1991 Washington State Energy Code and using electricity generated by a combustion turbine would use about 50 therms a year less gas than a gas-heated home built to the 1991 code. The reason is that the code requirements are different for gas and electric-heated homes in Washington's 1991 code.

Portland General Electric Studies

PGE did two studies of fuel conversions during the summer of 1992. One was done by Aos and Blackmon, using a method similar to the one described above, to estimate the cost-effective fuel conversion potential in the PGE service territory.[22] The other was done by PGE staff (Thompson and Eustis) and focused on cost-effectiveness of two specific fuel conversions.[23]

The Thompson and Eustis study looked at the cost-effectiveness of converting water heat in a home that already has gas space heat and converting both space and water heat in a home where a gas service connection is required. The study looked at cost-effectiveness from four different perspectives: societal, conversion participants, electric utility customers and gas utility customers. For their base case assumptions, both conversions were cost-effective from all perspectives with one exception -- the conversion of both space and water heat to gas had a small negative impact on gas utility customers, since the gas utility is assumed to pay the service hookup costs.

Thompson and Eustis examined the sensitivity of the results to several changes in assumptions. They found that the results were most sensitive to the level of consumption and the avoided cost of electric resources. Sensitivity to the relative cost of electricity and natural gas, installation costs, free riders and marginal gas cost was moderate to small.

The Aos and Blackmon study of fuel conversion potential in the PGE service territory extended their previous work by evaluating five different consumption levels for space and water heat. Fifty-seven percent of PGE's current single-family residential customers were estimated to use electricity for space or water heating; an estimated 55 percent of these have access to natural gas and are physically

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[22]Residential Fuel Conversion Potential and Cost-Effectiveness: Portland General Electric Service Area, Steve Aos and Glenn Blackmon, July 15, 1992.
[23]Residential Fuel Substitution in Integrated Resource Planning: An Economic Analysis, Mark E. Thompson and Conrad Eustis, ACEEE 1992 Summer Study on Energy Efficiency in Buildings, Panel 8 on Integrated Resource Planning.

able to convert. Aos and Blackmon constructed supply curves for water heat only as well as space and water heat conversions that contained about 150 segments based on consumption levels, current equipment and fuel types, housing types and access to natural gas. When these supply curves were compared to PGE's avoided costs, virtually every segment was found to be cost-effective. After adjusting for conversion as a result of market forces, about 23 percent of the households having electric space or water heating were considered potential program conversions that could save PGE 49 average megawatts of electricity.

PGE is now in the process of extending its fuel conversion study. At the request of the Oregon Public Utility Commission, it will study the behavioral factors that affect consumer fuel choice. The goal is to understand better why consumers decide for or against changing heating fuels.

Appendix C

Regional Fuel Conversion Programs

Interest in fuel conversion programs has been growing in the region, driven by energy-efficiency arguments and made even more appealing by the improving economic and political attractiveness of natural gas. The studies cited earlier in this paper are evidence of growing interest, but some organizations have moved beyond studies to conduct experiments in fuel switching programs and, in one case, to run an aggressive energy-efficiency program. This section briefly reviews some of the regional experience in fuel conversion programs.

One of the earliest efforts was a joint Snohomish County PUD No. 1 and Washington Natural Gas pilot project to encourage switching from electric to natural gas water heat. In a selected community with a large incidence of electric water heat and gas space heat, 1,426 households were contacted. Ultimately, the pilot project resulted in 209 customers converting their water heaters to natural gas. The program resulted in a much larger response than typically had been observed for programs run by Washington Natural Gas alone. The involvement of both utilities appears to have lent the program more credibility in the customer's eyes.

In 1991, Washington Water Power, a combination gas and electric utility, ran a test program to gauge the effects of different incentive levels on conversions from electric to natural gas space and water heat. Two different market areas were chosen, Coeur d'Alene and Lewiston/Clarkston. Direct mail campaigns were run in both areas describing the benefits of changing to gas space and water heat. However, in Coeur d'Alene customers were offered substantial financial incentives and asked to pay a shared savings charge over five years. In Lewiston/Clarkston customers were only offered zero-down market rate loans. The result was that the program had a 20 percent penetration rate in Coeur d'Alene but less than a 2 percent rate in Lewiston/Clarkston for space and water heat conversions. A similar result was obtained for water heat only conversions.

Washington Water Power is now running a fuel-efficiency program as part of its integrated resource plan. The company provides a grant up to $2,700 for space and water heat conversion. Customers pay any cost above that plus $19 a month to recover lost margin payments from the reduced electricity sales. The program requires minimum efficiencies for gas-fired equipment that is installed. The savings from the fuel-efficiency program are a very significant part of the company's integrated electricity resource plan, accounting for about 38 percent of the 212 average megawatts of demand and supply side resources to be acquired by 2011. Washington Water Power estimates the program costs born by the electric system to be about 25 mills per kilowatt-hour compared to an avoided cost of 68 mills per kilowatt-hour. Customers who convert both space and water heat are estimated to save over $300 a year in total energy bills, taking into account the lost margin payments and the costs of natural gas.

The Bonneville Power Administration is experimenting with fuel conversion programs that are initiated by the customer utilities. Bonneville has allocated about $2 million toward this effort to demonstrate the potential benefits from fuel conversions and to gather information to guide future fuel choice policies. Three projects have been initiated. One is a study of the consumption levels at which fuel conversions become cost-effective and the effects of fuel conversions on electric utility rates and consumer costs under different financial arrangements. This study will be done for the Salem Electric service area. A second project is the conversion of an industrial heating process at the Kaiser-Trentwood rolling mill from electric to natural gas. The estimated cost to Bonneville of the 2.4 average megawatts of electricity savings is 2.8 mills per kilowatt-hour in 1993 dollars. The third project is a joint electric and gas utility test of residential fuel conversion programs. In this project, Seattle City Light and Washington Natural Gas will develop targeted area conversion programs designed to achieve more efficiency in conversion costs. Control areas will be established and data collected on the costs and effectiveness of the program. All of these pilot studies are contributing information to the question of whether fuel conversion programs are cost-effective to electric utilities and their customers and how well such programs might be expected to work.

Fuel efficiency actions have also taken place in the regulatory arena in Oregon. The Oregon Public Utility Commission and the Oregon Energy Facility Siting Council have required that investor-owned utilities consider fuel efficiency programs in the context of their integrated resource plans. The OPUC would allow utilities to recover the costs of such programs if it can be demonstrated that they are economical, promote energy efficiency and are cost-effective to customers of both gas and electric utilities. To date, no proposals have been forthcoming from the utilities.

In a different area of energy efficiency, a project is being undertaken by the Washington State Energy Office and sponsored by Oak Ridge National Laboratory to conduct an experiment in joint gas and electric utility planning. The project is called the Puget Sound Fuel Blind Integrated Resource Planning Project. Utility participants in the study are Washington Natural Gas, Puget Sound Power and Light and Seattle City Light. In its initial report the study group decided to focus on six areas for potential joint planning benefits: (1) examining differences in service extension investment rules, (2) opportunities for targeting fuel conversions in a geographically targeted manner to relieve system constraints or avoid distribution system expansions, (3) joint pipeline capacity subscriptions, (4) fuel cell technology, (5) cogeneration siting to minimize adverse pipeline impacts and

(6) achieving economies through joint trenching for distribution expansions. This project holds significant potential for advancing joint gas and electric planning opportunities.

Several other groups have been convened to improve coordination and communication between the gas and electric industries. The Council's 1991 Plan called for the formation of a Gas Policy Group made up of Council members and policy leaders from the natural gas industry. That group has met and begun some mutual educational briefings. As policy level issues mature in the Council's natural gas study, of which this paper is a part, that group is likely to be convened to discuss them. On a more technical level, the Council has formed a Natural Gas Advisory Committee to held guide the natural gas study. This group has been very helpful in developing issue papers and framing analysis. Recently a Pacific Northwest Gas/Electric Integration Group has been formed with representatives from natural gas pipelines and electric and gas utilities. This group is oriented toward improving operational coordination, which will be important as more natural gas-fired electric generation comes on-line in the region. Some cooperative ventures between electric and gas utilities are already appearing. For example, Portland General Electric and Northwest Natural Gas have developed a joint gas transportation agreement that will benefit both parties.

With the regulatory changes that have taken place in the natural gas market and the possibility that similar ones will affect the electric industry in the future, incentives should be in place to encourage cooperation between the two industries to help ensure a more efficient use of all forms of energy in the region. The question for the Council is what policies it should adopt, if any, to help advance and facilitate total energy efficiency.

Appendix D

Fuel Conversion Analysis

Introduction

As described earlier in this paper, a number of studies have evaluated the potential for fuel conversions in the Pacific Northwest. This study is intended to build on these previous studies and to add value in two principal ways. First, the method used here to estimate the cost-effective potential is significantly different from those used in other studies. While it necessarily uses many of the same analytical components as previous studies, it uses a much more rigorous treatment of the uncertainty in these components to estimate the magnitude of the resource potential.

Second, this analysis uses the Council's system planning models to value the fuel conversion resource potential from a regional power system perspective. This allows for evaluation of the economic and environmental effects of resource acquisition in direct comparison with the array of alternative resources in the regional resource portfolio. It also allows explicit incorporation of the effects of other regional planning uncertainties, such as load growth, hydro conditions and fuel price.

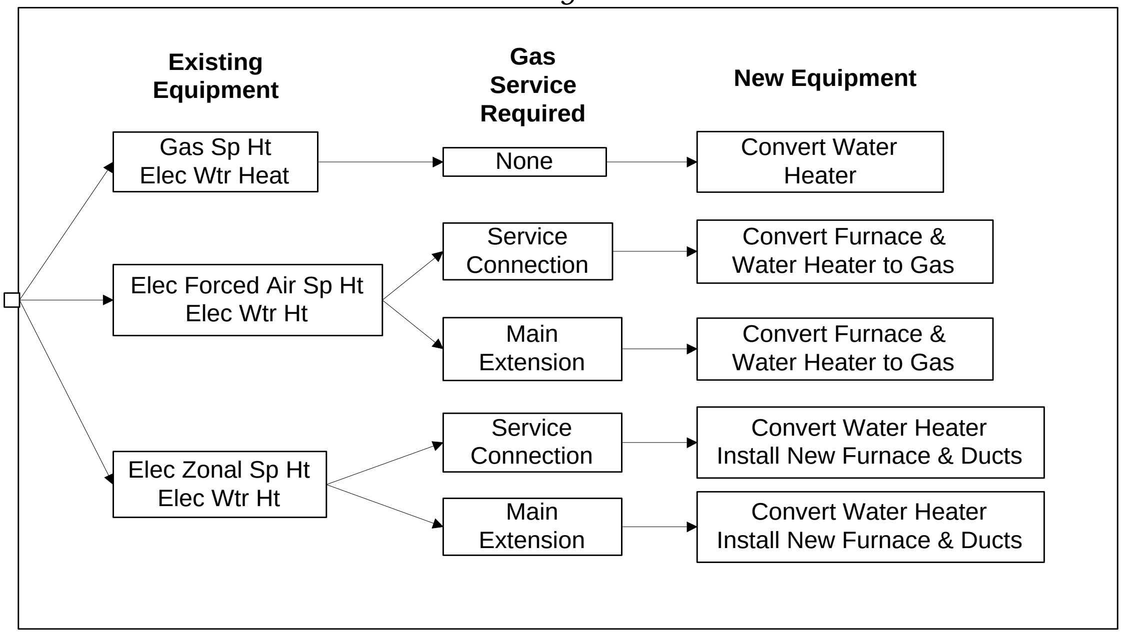
This appendix is organized into two principal sections. The first describes the methods and data assumptions used to estimate the technical and economic potential for the size of the conversion resource. The second addresses the economic and environmental effects of acquisition of the conversion resource from a system perspective.

Methods and Data Assumptions

<u>Market Definition and Segmentation</u>

The target market for this analysis is existing single-family, detached residences. Single-family residential is the market segment which has been consistently identified with the highest potential savings. It is also the segment for which the best quality data is available and is also probably the most receptive to the marketing of fuel conversion programs. For purposes of this study, the single family residential segment is subdivided into the five categories shown in Figure D-1. The differentiation is based on the type of water and space heating equipment present in a home and the type of gas connection required to provide gas service to the residence. Note that for the four categories where a space heat

Figure D-1
Market Segmentation



conversion takes place, this study assumes that the water heat conversion will be done as well. The possibility of providing new gas service to an electrically heated home and converting only the water heater is not considered. This allows the allocation of the service connection and gas main extension costs across the entire load reduction associated with the residence. Note also that homes with heat pumps are excluded from this analysis.

Evaluation Methodology

Probably the most significant difference between the evaluation approach used here and that used in previous studies is in the treatment of uncertainty. The cost-effectiveness of the conversion for an individual structure will be determined by a number of parameters, many of which have a significant degree of uncertainty about them. Because of the variation in these parameters, the candidate homes will also have significant variation in the ultimate cost of conversion. This analysis attempts to explicitly account for the uncertainty in the most important of these parameters. These include:[24]

[24]Natural gas price uncertainty can also have a significant effect on the ultimate cost of the conversion resource. However, if fuel conversion is compared to new gas-fired electrical generating resources, this uncertainty is present on both sides and will largely tend to net out the analysis. The effect of fuel price uncertainty is addressed in the system analysis section of this appendix.

- Water heat usage;
- Space heat usage;
- Heating equipment cost and cost of installation;
- Natural gas main extension costs; and
- Natural gas service connection costs.

The earlier studies did not directly address the uncertainty in these parameters. Instead, those analyses developed estimates for the mean values of these variables and used these single point values to estimate the cost-effectiveness for entire market segments.[25]

The effect of the variation in these parameters is incorporated here through a spreadsheet simulation model. Given a characterization for the uncertainty in key variables, simulation is a straightforward way to capture the effect that these stochastic variables can have on an outcome of interest, e.g., the levelized cost of fuel conversion. It essentially allows one to ask hundreds or thousands of "what if" questions and keep track of the answers quickly and efficiently. It is incorporated here through a software product called @RISK, which augments Microsoft Excel to provide simulation capability.

The methodology applied here is probably best illustrated through the use of a diagram. Figure D-2 shows an example calculation for a single pass through the logic for the zonally heated/main extension market segment. A similar analysis is performed for each of the five single family categories. What follows is a description of the simulation approach depicted in Figure D-2.

1. Take a random sample from the house size distribution for electrically heated homes with zonal heating systems.

2. Using an estimated relationship between house size and space heat usage, calculate the mean and standard deviation for space heat usage at the house size observed in step 1.

3. Using an estimated relationship between house size and water heat usage, calculate the mean and standard deviation for water heat usage at the house size observed in step 1. (Except for the effect of house size, the results for space heat and water heat usage are assumed to be independent from each other.)

4. Sample from a distribution of water heater conversion costs to obtain an observed value for the capital cost of gas water heat installation.

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[25]The July, 1992, Aos/Blackmon study recognizes that a distribution of cost outcomes is applicable to fuel conversion and arbitrarily assumes a uniform distribution with upper and lower bounds equal to a deterministic estimate ± 1.5 cents/kwh.

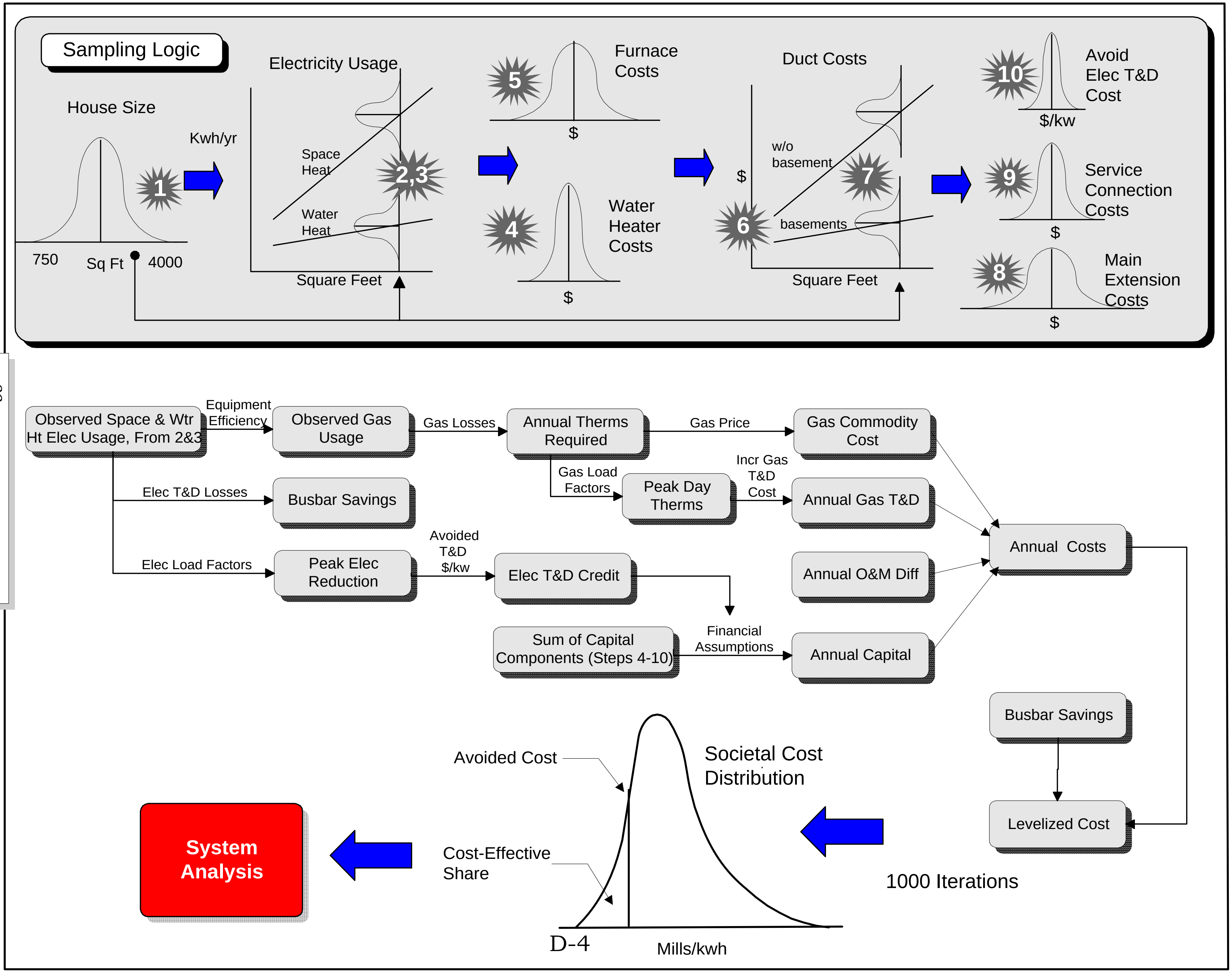


Figure D-2.
Evaluation Methodology

5. Sample from a distribution of furnace conversion costs to obtain an observed value for the capital cost of gas furnace installation.

6. Sample to determine if this house has a basement.

7. Using an estimated relationship between house size and cost of duct installation for basemented or non-basemented homes, calculate the mean and standard deviation for the duct cost distribution and draw a sample from this distribution to get an observed value for the duct installation cost.

8. Draw a sample from a distribution for main extension costs.

9. Draw a sample from a distribution for service connection costs.

10. Draw a sample from a distribution for electrical transmission and distribution avoided investment costs.

Steps 1-10 provide all of the information required for the uncertain variables present in the analysis. Except for the effect of house size, all of the distributions referenced above are assumed to be independent of each other. The rest of the calculation simply involves combining the information for these stochastic variables with other deterministic data to estimate the total cost of conversion for this specific installation. The actual spreadsheet used is shown in Table D-1, located at the end of this appendix.

When this calculation is completed, it represents the results for a single hypothetical installation. The results are recorded and the process is repeated many times to develop the distribution of outcomes which would be representative for all homes in this market segment. The resulting distributions can then be used to estimate the portion of the population for which conversion would be cost-effective and to identify the relevant characteristics for this population subset.

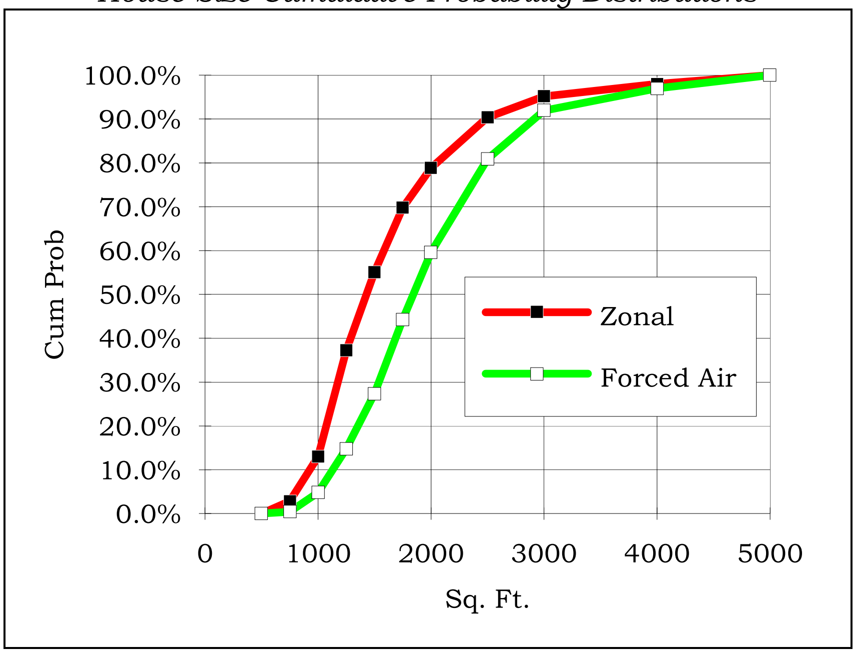
Data Development and Assumptions.

While this analysis uses a rigorous treatment of the uncertainty in the major cost and thermodynamic components associated with fuel conversions, it does not lessen the need for confidence in the quality of the data used. Changes in either the mean or shape of an input probability distribution will affect the conclusion about how much of a given market segment is cost-effective. The data used in this analysis was derived from a number of sources with varying degrees of quality. The usual time constraints applied, and there are probably a number of areas where the assumptions could be improved with better information. The following section is a description of the major assumptions used in the @RISK spreadsheet analysis.

House Size Distribution

The data for house size distributions comes directly from the 1992 Pacific Northwest Residential Survey (PNRES92) conducted by Bonneville. PNRES92 data represents the characteristics of the existing housing stock in 1992. The Council also uses this data for calibration of its demand models. Data is available for electrically heated single-family detached homes for a number of heating system types. The cumulative probability distributions used for both forced air and zonal heating systems are shown in Figure D-3. The mean house size for forced air systems is 1,983 square feet and for zonal systems, 1,613 square feet.

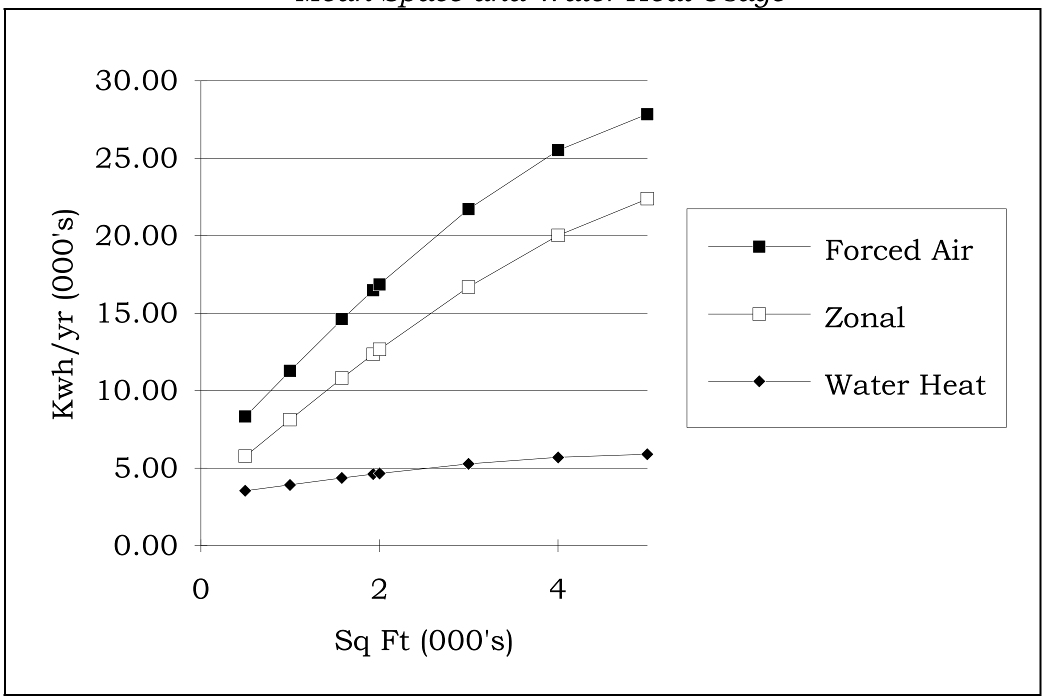
Figure D-3.
House Size Cumulative Probability Distributions



Space Heat Usage vs. House Size

The space heat usage data used in this study is derived from several sources. The Washington State Energy Office (WSEO) through the Washington State Thermabilt Program supplied data for a control group of about 150 electrically heated homes built before 1985. This data was used to estimate the general relationship between size and usage for all electrically heated homes. A simple linear regression on the WSEO data resulted in a slope of approximately 5.5 kilowatt-hours per square foot of floor space. To represent an approximate 25% efficiency difference between forced air systems and zonal systems, this slope was modified to 6 kilowatt-hours per sq. ft. and 4.8 kilowatt-hours per sq. ft. for forced air and zonal systems, respectively. It was the opinion of the Council's conservation staff that these slopes would be skewed for the larger house sizes due to behavioral effects, such as room closures, or physical constraints, such as heating system capacity. This effect was implemented through the use of a cubic equation. Figure D-4 shows the mean relationships between house size and space heat use for both heating system types.

Figure D-4.
Mean Space and Water Heat Usage



In addition, for the study to be consistent with the Council's demand forecast, it was required to calibrate the mean usage values for the entire population in this analysis to the values used in the Council's demand models. This was done by adjusting the intercepts for both heating system types until the mean usage values matched those in the Council's demand models.

The variance for these distributions was estimated using the Thermabilt data. The data were grouped into three categories of under 1,500 sq. ft., 1,500 to 2,000 sq. ft., and over 2,000 sq. ft. The means and standard deviations for each group were calculated. This resulted in coefficients of variation (the standard deviation divided by the mean) of 0.38, 0.44 and 0.38 for the three groups. To simplify the analysis, a coefficient of variation .4 was used in this study. The distributions were also observed to be skewed to the upper end. To represent this skewness, log normal distribution types were assumed. Figures D-5 and D-6 show the resulting distribution at house sizes of 2000 square feet for the two system types.

Figure D-5.
Forced Air Space Heating Use @ 2000 sq. ft.

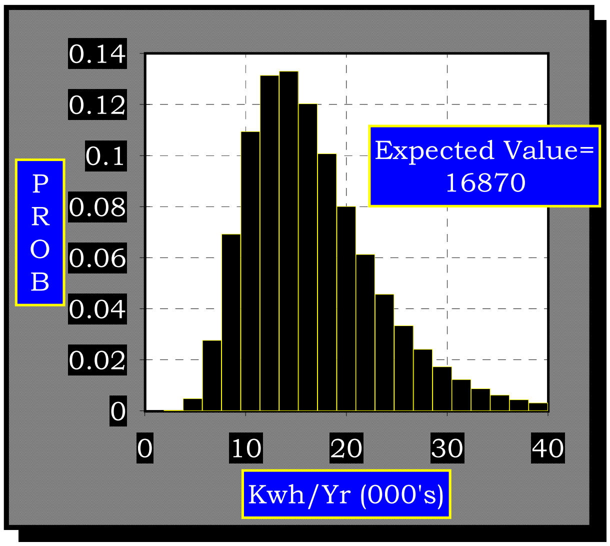
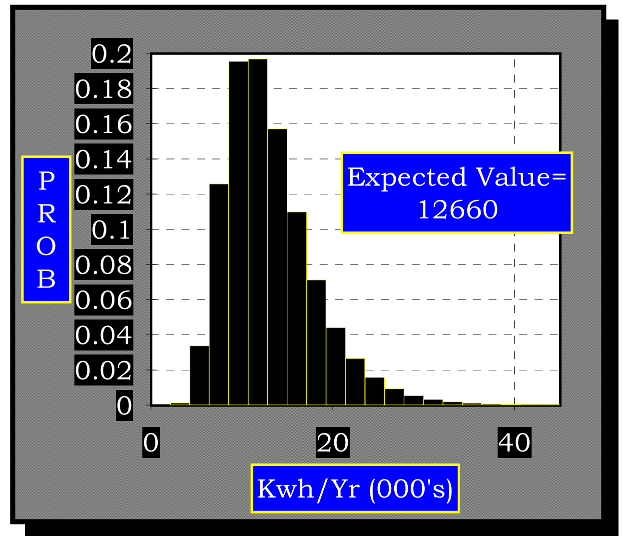


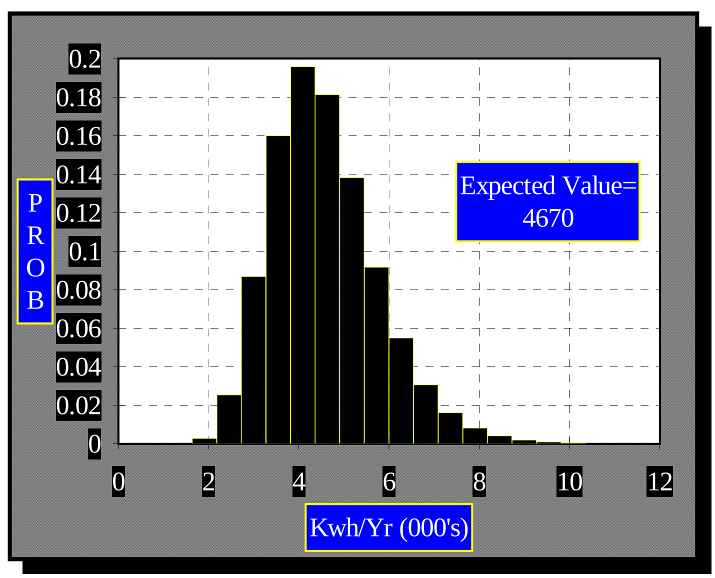
Figure D-6.
Zonal Space Heating Use @ 2000 sq. ft.



Water Heat Usage vs. House Size

The relationship between water heat usage and house size was estimated using data from the End Use Load and Consumer Assessment Program (ELCAP) conducted by the Bonneville Power Administration. Data on residential end use from the period 1986 to 1992 is contained in the *Description of Electric Energy Use in Single Family Residences in the Pacific Northwest*, December 1992. This document provides summary data for water heat usage as a function of house size for several different size categories. The approximate slope was estimated using the data for the base study. Calibration to the Council's demand models was performed in a manner similar to that for space heat. The intercept

Figure D-7.
Water Heat Use @ 2000 Square Feet



was modified to provide a mean usage for the population that was equal to the mean water heat use in the Council's 1991 demand forecast. By inspection of the ELCAP data, the coefficient of variation was estimated to be .25, and as with space heat, the usage distribution is skewed to the high end. Again, a log normal was used as the distribution type. Figure D-4 displayed the relationship used between house size and mean water heat usage. Figure D-7 shows the usage distribution that occurs at a house size of 2000 square feet.

Equipment Conversion Costs

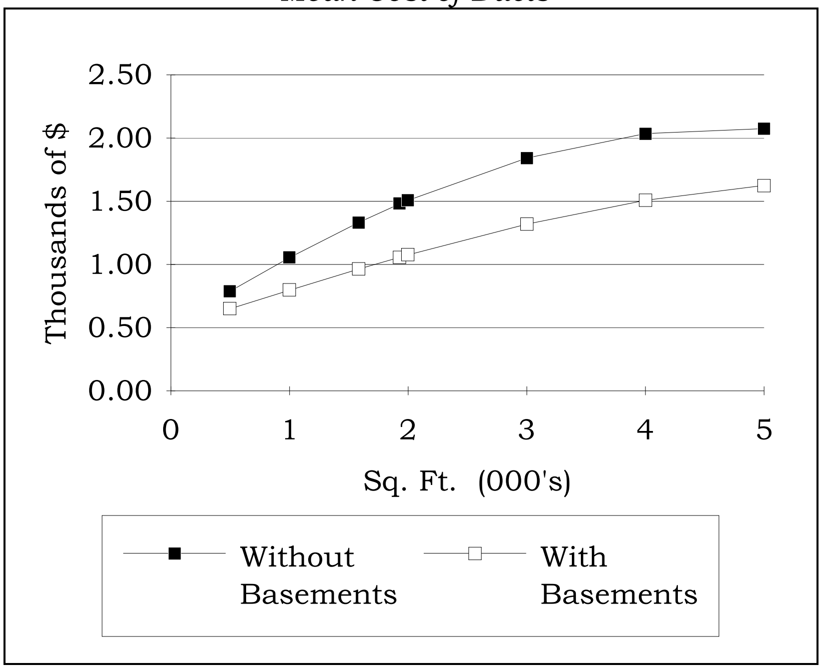
Equipment conversion costs include the capital and installation costs for water heaters and gas furnaces. However, since the issue is the comparison of natural gas use instead of electricity to fuel these appliances, the appropriate cost is the difference between the cost of installing gas equipment and the cost of replacing electric equipment as required through the study period. This study uses a physical life for ducts and gas mains of 40 years. Water heaters are assumed to last 13 years and furnaces 23 years. To capture all of the costs, the capital cost value should reflect the differential cost of replacement several times over this full 40 year horizon.

The Aos/Blackmon study recognized these issues and used a capital costing method consistent with an incremental replacement and vintaging framework. Their cost assumptions were based on data available from the Washington Water Power conversion program and were reviewed by WSEO. The mean values used in the analysis here use the Aos/Blackmon assumptions for incremental equipment replacement costs for the water heaters and furnaces, adjusted to 1990 dollars. They are $453 for water heat, $1,153 for gas forced air over electric forced air and $1,754 for gas forced air over zonal. Equipment conversion costs are not assumed to be a function of house size because of the differential gas versus electric relationship. While it is true that larger homes would require larger systems, it is assumed that most of the cost increase due to size would be present for both gas and replacement electric equipment and would tend to be equal. The equipment cost distributions are assumed to be normal, with standard deviations of $50 and $150 for water heat and furnace costs, respectively.

Duct Costs

Costs of a new duct system are only required in the case of conversion of a zonal heating system. Conversion of a forced air system would allow use of the existing ducts. The data for cost of a new duct system is based largely on information from the Washington Water Power $Switch $Saver program. Data obtained from WWP on duct costs showed an average cost of about $.38 per sq. ft. of floor space. However, over 80 percent of the homes in this sample had basements. Duct systems are likely to cost significantly less in basemented homes than in homes with crawl spaces. Data gathered for a Council cost of heating study done in 1988 estimated costs of ducts in crawl space homes to be over $1.00 per sq. ft. This analysis differentiates between homes with and without basements and assumes that 25 percent of the homes in the region have basements. Based on the WWP data, the assumption used here is that the mean duct costs for homes with basements is about $.30 per sq. ft. Mean duct costs for crawl space homes are assumed to be about $.60 per sq. ft. with an absolute upper limit of about $2,000. The coefficient of variation is estimated at 0.4 based on the WWP data. The mean relationships are shown graphically in Figure D-8.

Figure D-8.
Mean Cost of Ducts

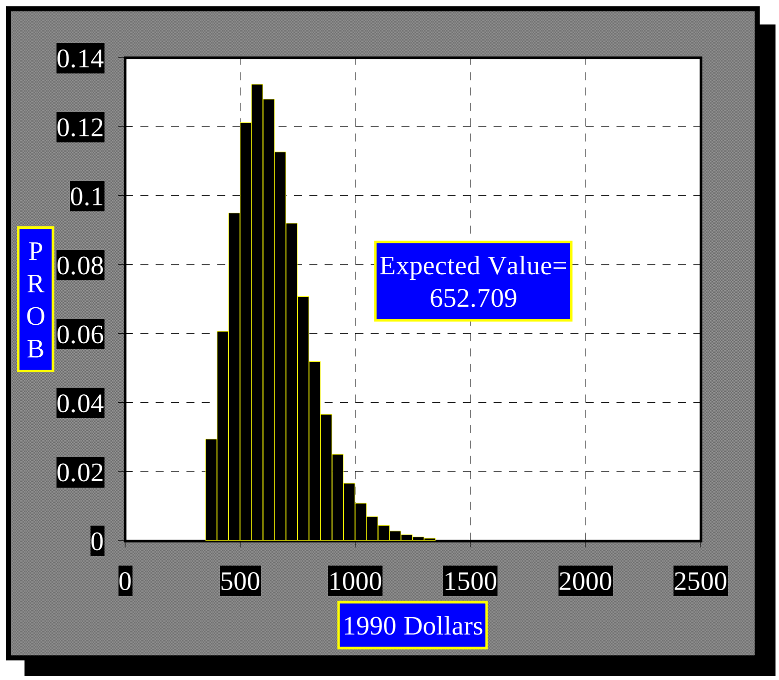


Service Connection Costs

Service connection costs refer to connecting a house to a gas main that already runs down the street in front of the house. A distribution of gas service connection costs is shown in Figure D-9. The distribution of gas service connection costs was based on data provided by Washington Water Power and Washington Natural Gas. Derivation of average service connection costs is fairly straightforward and can be based on gas utility experience. Utilities often contract with independent companies to do service extensions. For example, Washington Natural Gas does so at a fixed price per hookup that ranges between $590 and $647 per house.

Variations in the cost of service connection are due to the distance from the house to the gas main at the street, the type of soil conditions and the frequency with which more than one home can share the main connection. Washington Water Power provided data on service connection costs. There were fixed costs for the meter, the "bell hole" where connection to the gas main occurs and street repair. The latter two may sometimes be shared by two houses. In addition, there are variable costs that depend on the number of feet from the street to the house and the type of soil encountered. Washington Water Power provided some information on the distribution of distances which they have experienced. Variations in distance to the street and sharing of fixed costs led to a fairly uniform distribution of estimated costs; however, the soil conditions contribute much more cost to the upper end of the cost distribution. Trenching and pipe cost per foot varied from $2.70 a foot for normal soil to $8.65 a foot for loose rock to $20.85 for solid rock. It was assumed that average conditions cost $3.00 a foot, close to normal soil conditions. It was assumed that $2.70 was the minimum and $10.00 the maximum.

Figure D-9.
Service Connection Cost Distribution



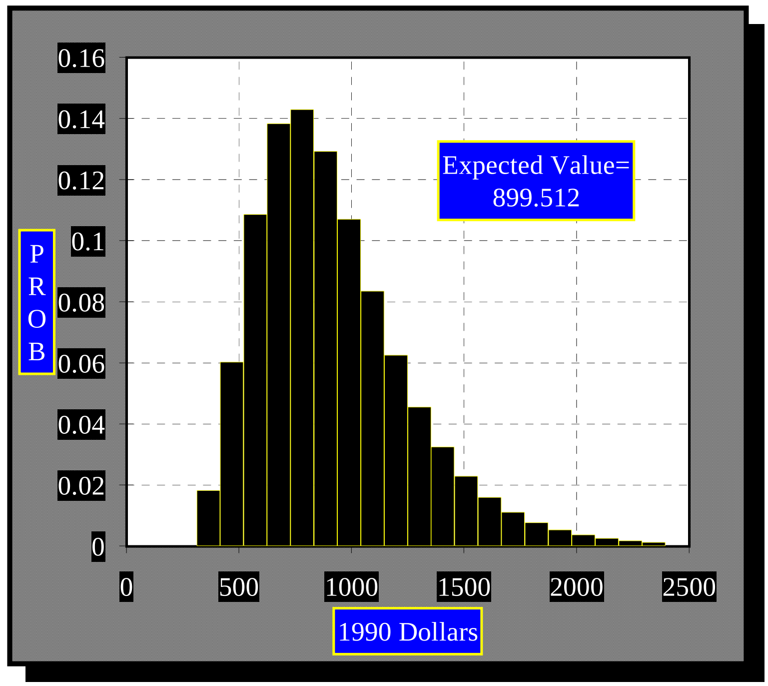
Main Extension Costs

Main extension costs refer to the cost of extending gas mains to serve new neighborhoods. Figure D-10 shows the distribution of costs for main extension. Estimation of a cost range for main extensions is more difficult than for service connections. The major difficulty is that the costs per house depend on the number of homes that will be served by the main extension. The number of homes served may be relatively sparse initially, resulting in a fairly high cost per house. However, over time as additional homes hook up to the gas main, the average costs will decrease. Although Washington Water Power provided estimated fixed and variable construction costs, there is little information available on the number of customers captured for any given line extension, even initially.

An additional complication is that the costs of main extension should conceptually be consistent with the estimate of the number of homes that can be reached with a main extension. If homes in sparsely settled areas surrounding towns with gas service were included, then the range of costs of main extension should reflect the fact that some share of the homes would be very expensive to reach. Unfortunately, data are not available to be that precise about the nature of possible main extensions.

In developing an estimate of a distribution of main extension costs, the assumption is made that we are dealing with a potentially economically viable extension. A one-quarter mile main extension was arbitrarily assumed. It was further assumed that the extension was on a street with homes every 60 feet on both sides of the street. The estimated distribution of cost depends on variations in fixed cost based on the size of pipe installed, variations in variable costs depending on soil conditions and variations in the assumed number of available homes that hook up to the gas line. For the lowest cost end of the distribution, it was assumed that all of the available homes hook up, for the mean it was assumed that one of two homes hooks up and for the high end it was assumed that only one of four hooks up. Each of these factors resulted in more variation on the high end of the costs, thus skewing the cost distribution to the high end of the range.

Figure D-10.
Main Extension Cost Distribution



Natural Gas Costs

The natural gas price assumptions used here are based on the July, 1993, revision of the Council's natural gas price forecasts.[26] Gas commodity prices are consistent with the medium price scenario. A levelized commodity price of $3.35 per million Btu (1990 $) is used in the spreadsheet analysis. It's derived from a 40-year time series beginning in 1995 with 30 years of real escalation consistent with the medium price forecast. Based on input from the Council's Natural Gas

[26]Staff Issue Paper, *Natural Gas Supply and Price*, June,1993. Request document 93-4.

Advisory Committee, a value of $5 per peak-day therm was used for incremental transmission cost. Gas prices are treated deterministically in this portion of the analysis. The effect of price uncertainty is addressed in the system analysis section of this appendix.

The remaining data parameters were also treated deterministically. They are shown in the top section of the sample spreadsheet in Table D-1.

Simulation Results and Estimation of Resource Potential.

Using the method and data described above, simulations were performed using Excel and @RISK to estimate the distributions for societal costs for each of the five market segments. One thousand iterations were used for each market segment. The resulting distributions are displayed in Figures D-11 through D-15. These figures are frequency distributions for the estimated societal costs of fuel conversion expressed in levelized 1990 mills per kilowatt-hour. They are shown on the same horizontal scale to facilitate comparison.

Figure D-11.
Water Heat Only Societal Costs

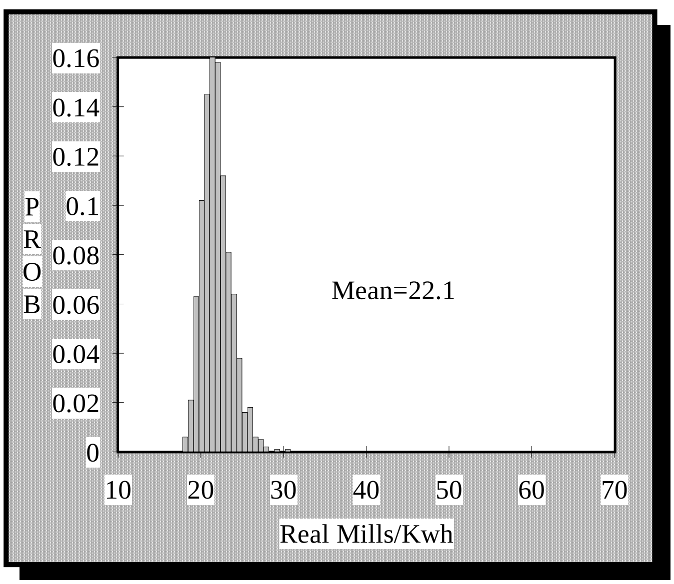


Figure D-12.
Forced Air/Service Connection Societal Costs

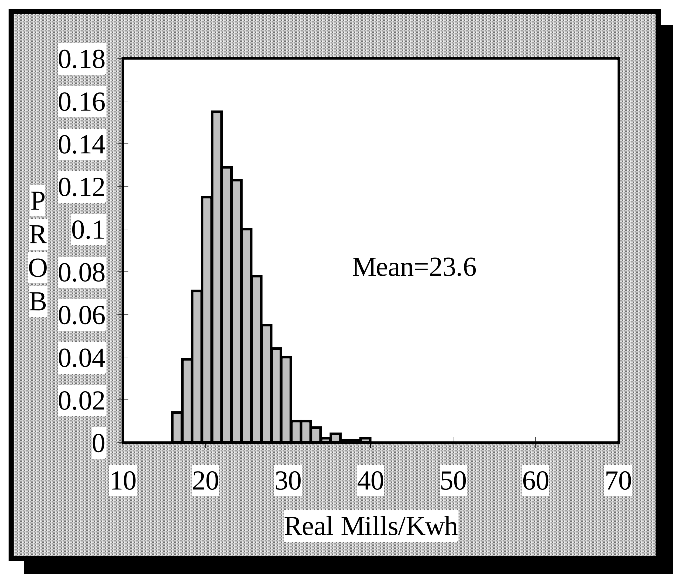


Figure D-13.
Forced Air/Main Extension Societal Costs

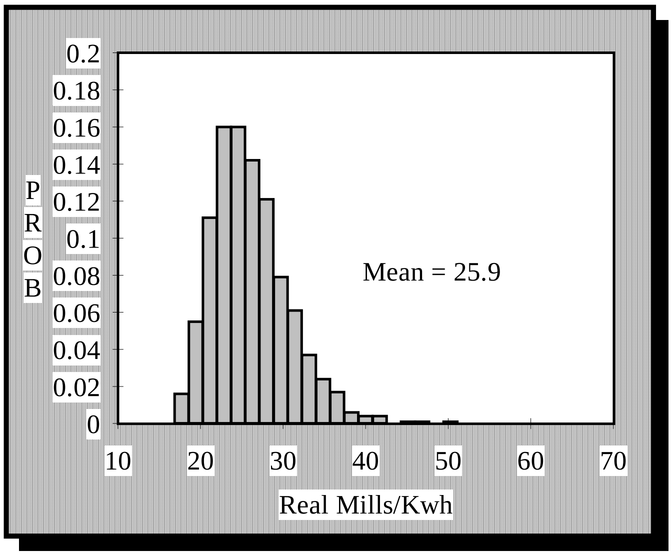


Figure D-14.
Zonal/Service Connection Societal Costs

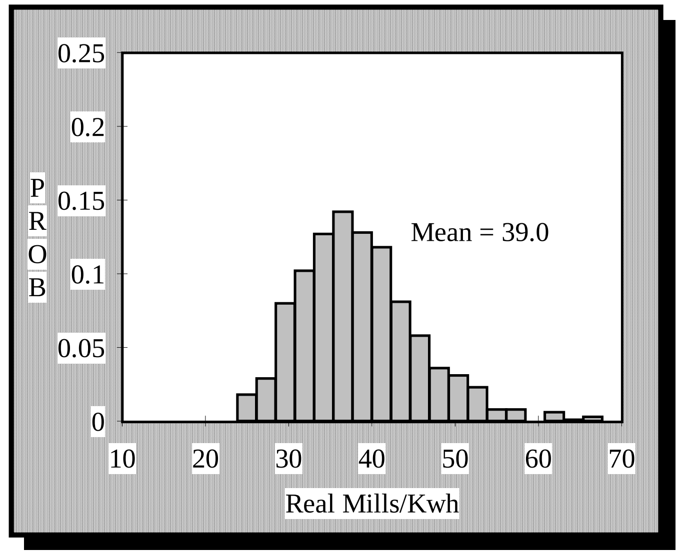
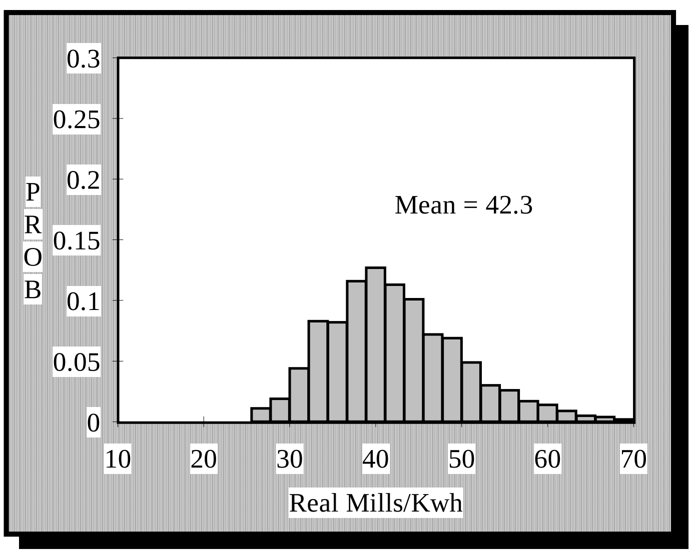


Figure D-15.
Zonal/Main Extension Societal Costs



The results show a wide range of outcomes. For the water heat only case, the distribution is relatively narrow, ranging from about 18 to 28 mills per kilowatt-hour. However, for the zonal/main segment the results range from 26 to over 70 mills per kilowatt-hour. The difference in the range of the outcomes arises from the number of underlying uncertainties which are applicable to each segment. The water heat only segment is subject only to the uncertainties of water heat usage, water heater conversion cost and avoided electrical transmission and distribution. On the other hand, the zonal/main category is subject to uncertainties in both water and space heat usage, conversion costs for both water heater and furnace, duct costs, gas main extension costs, gas service connection costs and the avoided electric transmission and distribution costs.

Avoided costs for the regional power system were developed specifically for this analysis using ISAAC, the Council's primary system planning model.[27] Separate avoided costs were calculated for reductions in typical water heat and space heat loads beginning in 1995 and lasting for 40 years. These studies were performed using 100 future paths for regional load and water conditions. The backstop generating resource in the resource portfolio used here is a gas-fired combined cycle plant with a heat rate of 7,400 Btu per kilowatt-hour and an equivalent availability of 90 percent. On most load paths, this will be the avoided resource. The study uses the medium case of the Council's revised natural gas price forecasts, which is consistent with the assumptions used in the fuel conversion simulation analysis described above. The mean avoided costs resulting from these studies are 35.1 mills per kilowatt-hour for water heat loads and 36.0 mills per kilowatt-hour for space heat loads. These are expressed in 1990 real levelized mills per kilowatt-hour.

These avoided costs can be used to estimate the portion of each market segment where conversions are cost-effective. Segment-specific avoided costs are calculated using the relative space and water heat use for each market segment. The fuel conversion cost distributions from the @RISK analysis are compared against the appropriate avoided cost, and the portion of each distribution falling below avoided cost represents the cost-effective percentage for each population. These percentages can then be applied against the total number of homes in each market segment to estimate the economic potential for the conversion resource.

Table D-2 summarizes the results of this avoided cost screening. It shows mean costs and savings for the entire segment population, as well as the mean values for the set of observations that fall below avoided costs. All of the water heat only observations and virtually all of the forced air population are beneath

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[27]A complete description of ISAAC is contained in Volume II, Chapter 15 of the Council's 1991 Power Plan.

avoided costs. However, for zonally heated homes, about 34 percent of those requiring only service connections and about 22 percent requiring main extensions were found to be cost-effective. These are typically the homes in the higher size ranges for these segments. The mean house size used for all zonally heated homes is 1,613 square feet, while the means of the cost-effective shares are both over 2,000 square feet.

Table D-2.
Summary of @RISK Results

	Water Ht Only	Forced Air / Svc Conn	Forced Air / Main Ext	Zonal / Svc Conn	Zonal / Main Ext
Population Mean Societal Cost (m/kwh)	22.1	23.6	25.9	39.0	42.3
Population Mean Busbar Savings (kwh/yr)	4956	22355	22355	16038	16038
Mean Values for Cost-Effective Share					
Percent Cost Effective	100.0%	99.4%	96.8%	33.7%	22.2%
Lvl Societal Cost (m/kwh)	22.1	23.5	25.5	32.0	32.4
Lvl Gas Cost (m/kwh)	19.6	20.8	20.7	25.7	25.3
Lvl Capital Cost (m/kwh)	2.5	2.7	4.8	6.3	7.1
House Size (sq. ft.)	1983	1988	2007	2015	2163
Busbar Savings (kwh/yr)	4956	22441	22760	22510	24882
Gas Use (therms/yr)	263	1002	1016	1252	1383
Net Direct Capital	$209	$887	$1,757	$2,644	$3,343

The results of the analysis can also be used to estimate the total energy savings potential associated with fuel conversions. The process is illustrated in Table D-3. It starts with the number of existing single-family detached residences with zonal and forced air heating systems still extant in 2010 where natural gas would be available. This analysis assumes that 80 percent of the homes in the region could be accessed with natural gas. Of these, the assumption is that 58 percent could be reached with a service connection and the other 42 percent would require a main extension.

This value is reduced to an estimate of technical potential through an adjustment for the structural feasibility of conversion. The study assumes that 5 percent of segments 1 and 2 and 10 percent of the other three segments would have a structural barrier to conversion. (The use of 10 percent for segment 3 was an oversight. In further analysis for the power plan, this will be changed to the same as segment 2.) These barriers include things like inadequate space for venting or a zonal home with a slab foundation and no way to install ducts. Technical potential is reduced to economic potential with application of the fraction of each population estimated to be cost-effective with the @RISK analysis. The economic potential is an estimate for the number of conversions which could be obtained for less than avoided cost. The achievable potential values assume that 10 percent of this cost-effective population would not convert because of market barriers. This is similar to the 15 percent market barrier the Council uses for electrical conservation programs.

Table D-3. Estimation of Resource Potential

	Water Ht Only	Forced Air / Svc Conn	Forced Air / Main Ext	Zonal / Svc Conn	Zonal / Main Ext	Total
Units Potential						
2010 SFD Units with Gas Avl	289,941	101,169	72,661	210,412	151,121	
Structural Constraints	5%	5%	10%	10%	10%	
Remaining Tech Potential	275,444	96,110	65,395	189,371	136,009	
% Cost Effective	100.0%	99.4%	96.8%	33.7%	22.2%	
Economic Potential	275,444	95,534	63,302	63,818	30,194	
Market Barrier	10.0%	10.0%	10.0%	10.0%	10.0%	
Achievable Potential	247,900	85,980	56,972	57,436	27,175	
Energy Potential (MWa)						**Total**
Technical Potential	156	245	167	347	249	1164
Economic Potential	156	245	164	164	86	815
Achievable Potential	140	220	148	148	77	733
Low Market Scenario						
Market Conversion Energy	21	127	77	51	26	302
Residual Resource Potential	119	94	71	96	51	431
High Market Scenario						
Market Conversion Energy	94	211	129	86	43	563
Residual Resource Potential	46	9	19	62	34	170

The low and high market scenarios are attempts to bracket the amount of the achievable potential that will be captured by market forces over the next 20 years. Future market activity for conversions is highly uncertain, and a range is provided. The low market case is based on the Council's demand forecasting model prediction of conversions with the revised gas price forecasts. Since recent conversion activity has been significantly above the model forecasts, the high market-induced case is provided as an alternative view of the future. It assumes that conversion activity is closer to recent experience over the forecast period; 67 percent of the cost-effective water heat conversions and 71 percent of the cost-effective space heat conversions are assumed to occur over the next 20 years.

The resource potential analysis produces an estimate of 1,164 average megawatts of electricity that could be saved by using natural gas for space and water heat in the market segments considered. However, only 733 megawatts of these savings are cost-effective and achievable. Of this, the market is likely to obtain between 302 and 563 megawatts of these savings, leaving between 431 and

170 megawatts as possible targets for some form of policy or program to encourage cost-effective fuel conversions.

Evaluation of Fuel Conversion in a System Context

System Analysis

The estimate for the potential energy available from cost-effective fuel conversions provides a basis for evaluating the benefits of the resource in the context of the regional power system. From an electric system only perspective, the conversions of space and water heat look a lot like a conservation program. Capital is spent to provide some savings in future load and can defer development of new generating resources. From a societal perspective, the biggest differences from a true conservation program are the cost of the natural gas required to fuel the gas appliances and the air emissions associated with this use.

To facilitate evaluation of the conversion resource from both an economic and environmental perspective, the Council staff modified ISAAC to explicitly account for the cost and air emissions arising from direct use of natural gas. Essentially, a resource type was added that acts like a conservation program but also has a fuel component associated with it. This allows direct comparison between fuel conversions and other candidate resources in the regional resource portfolio.

The results of the @RISK analysis were used to develop representative data for the cost-effective portion of each of the five market segments. This data was shown in Table D-3 and represents the average values for the observations within a market segment which fall below the estimated avoided cost for that segment. Because fuel conversions are treated in a fashion similar to conservation programs, it was necessary to assume development rate limits to control the acquisition pattern for the resource. The maximum velocity and acceleration limits used in the ISAAC studies will allow full development of the potential electrical load savings in about 12 years. This is comparable to the assumptions used for modeling of weatherization programs. These data assumptions were then used in system studies to evaluate the potential impacts of fuel conversion.

While an estimate of the societal value of conversions could be obtained by using the difference between avoided costs and the levelized cost of the conversion market segments, it is preferable to use full system studies. This allows the evaluation of impacts across differing load levels, hydro sequences, gas price assumptions and timing of resource acquisition.

The market scenarios described earlier formed the basis for several ISAAC studies. First, a base case was run in which no fuel conversions were allowed to take place. The resource portfolio used in the base case was the same as that used to estimate avoided costs. It uses conservation and renewable assumptions that are generally consistent with the 1991 power plan but replaces all coal-fired generation with high efficiency gas-fired combined cycle. Medium case gas prices are used, and the study is performed over 100 future paths for regional load and water conditions.

Three other studies with differing levels of fuel conversions were run for comparison to the base case. The first of these is intended to determine the value to the region of full development of the single-family conversion resource. It uses the 730 average megawatts from Table D-3 as the full resource potential and adds it to the portfolio from which resources can be developed. The other two studies are based on the market assumptions shown in Table D-3. They are intended to place a range on how much of the societal value will be extracted by the market on its own.

One other change is made to each of the three cases involving conversions. Active fuel conversions of electrically heated single-family homes will reduce the savings potential of the single-family weatherization conservation programs being run in the region. When unweatherized electrically heated homes are converted to natural gas, those homes are no longer candidates for *electrical* conservation programs. Broad brush calculations indicate that the most severe impact would be a reduction of about 30 percent of the weatherization potential. This amounts to about 35 average megawatts. The single-family weatherization potential was reduced by this amount in all three of the conversion cases.

Figure D-16. Range of Benefits for Full Development of Fuel Conversion Potential

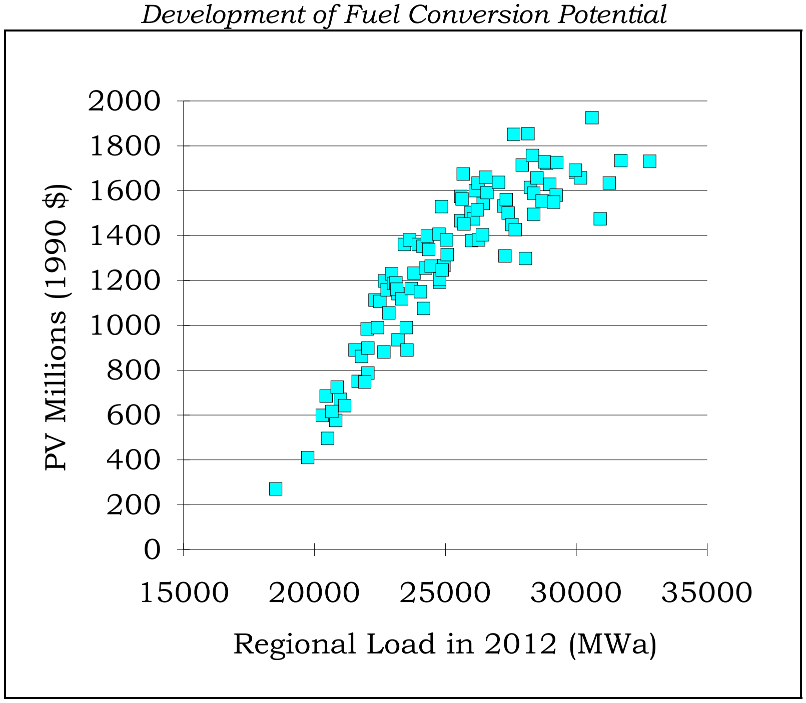
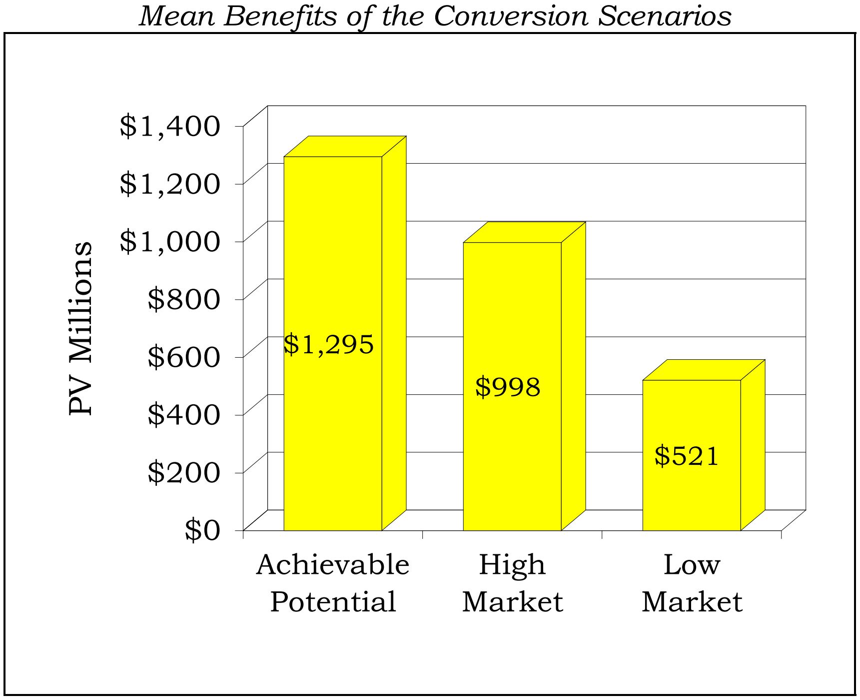


Figure D-16 displays the range of cost impacts observed by comparison of the base case to the first conversion case which has available to it the full economic potential of 730 megawatts. This scatter diagram shows the differences between the two cases in the present value of system costs versus long-run regional load. The values here indicate cost reductions, or benefits, associated with development of fuel conversions. These values include the cost of direct use of gas but do not include any administrative costs required to achieve this level of market penetration. A large range of values is exhibited from about $250 million in the lower load conditions to almost $2 billion in the higher load conditions. The mean reduction in societal cost is $1.295 billion. This is the expected value for the benefit of full development of the fuel conversion potential.

The strong correlation to long-run demand comes from several factors. In the lower load conditions, the region needs little resource development to maintain reliability, and so small amounts of the conversion resource are actually acquired. As loads increase, conversion begins to displace combined-cycle units. But under mid-range load conditions, the region may only develop 3000 to 4000 megawatts of combined-cycle generation over a 20-year planning horizon. This amount still permits a significant level of displacement with non-firm hydro and is, therefore, quite inexpensive generation. However, as loads increase to the higher levels and more combined-cycle is developed, displacement is less likely, the marginal combined cycle become more expensive and higher benefits accrue to conversion.

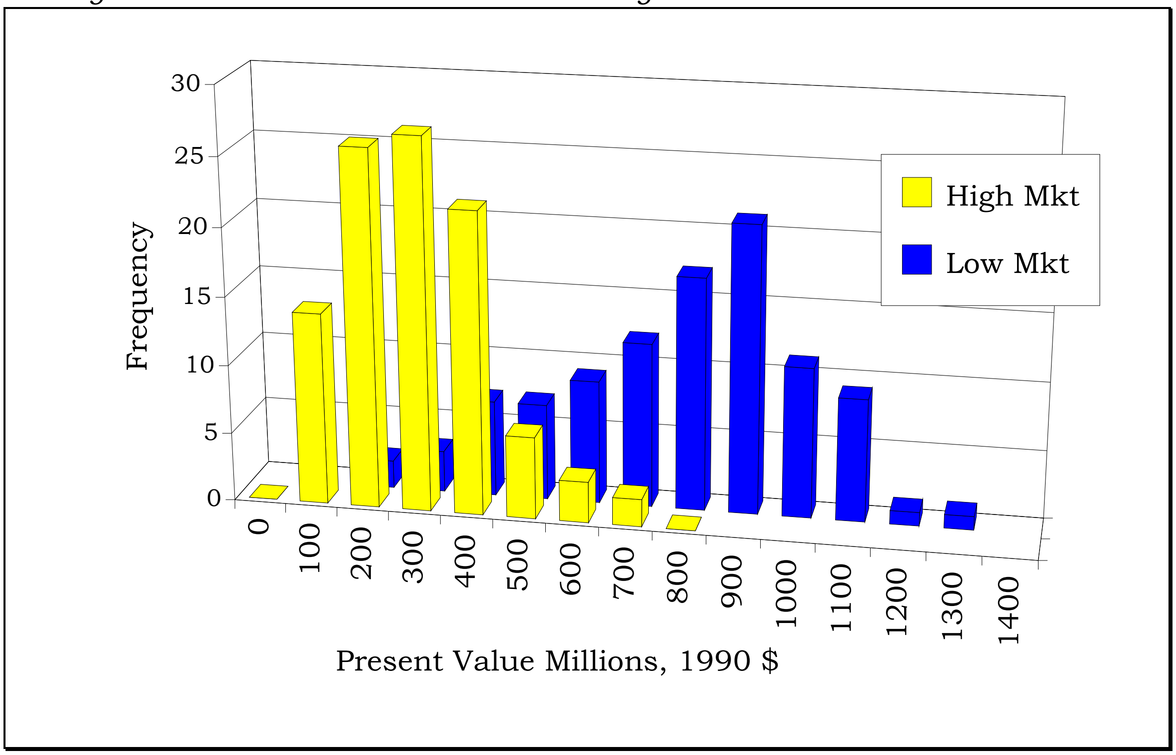
A comparison of the mean benefit associated with each of the three conversion scenarios studied is shown in Figure D-17. The savings are less for the two market driven cases because the amount of cost-effective resource captured is reduced. The mean benefits fall to $998 million for the high market case and $521 million for the low market case.

Figure D-17.
Mean Benefits of the Conversion Scenarios



The distribution of *differences* between the full economic potential scenario and the high and low market cases is shown in Figure D-18. This represents the range for the amount of benefit left in the conversion resource after the market-driven conversions have taken place. It is an estimate for the amount of economic value accruing to policies or programs which could capture the remaining cost-effective conversions. Residual value for the high market case ranges from $100 million to $700 million with a mean of $297 million. The high case captures most of the potential $1.3 billion benefit. However, if penetration is limited to the low market scenario, the region would see increased costs ranging from $200 million to $1.3 billion over the full development case. An expected value benefit of $774 million would be foregone without some sort of market intervention.

Figure D-18. Residual Economic Value beyond Market Induced Conversions

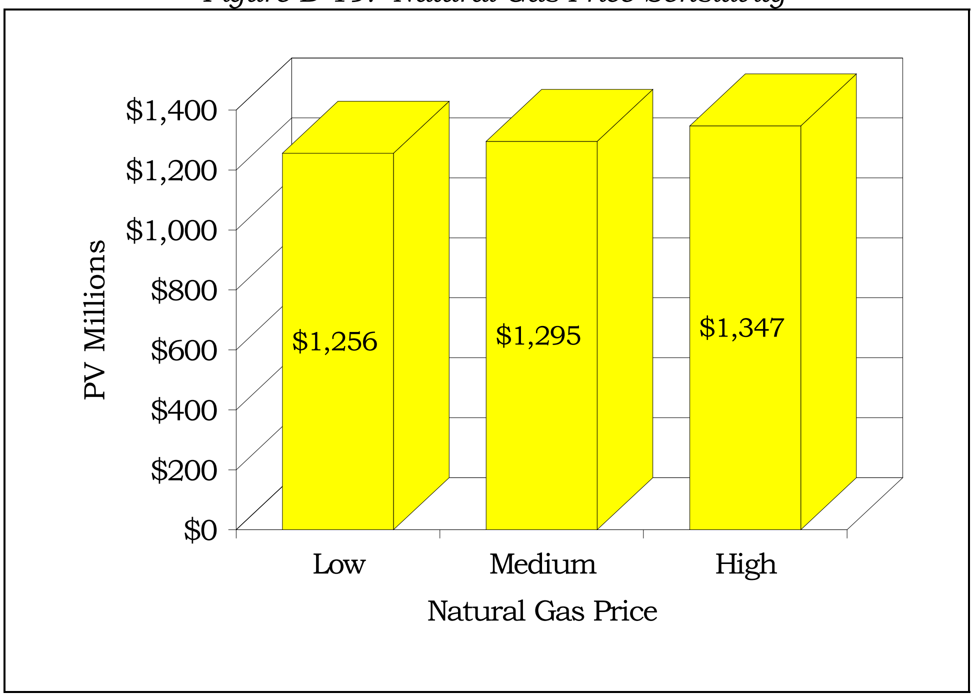


Natural Gas Price Sensitivity

Two additional studies were performed with ISAAC to evaluate the effect of different gas price escalation assumptions. These studies used the natural gas price assumptions in the low and high scenarios of the Council's revised natural gas price forecasts for both combined-cycle and fuel conversions. The base case portfolio again used combined-cycle as the predominant avoided resource. The full achievable potential scenario was used for the conversion resource. With these assumptions, the level of benefit associated with conversions is not very sensitive to changing gas price assumptions. The mean results are shown in

Figure D-19. The medium-case mean conversion benefit of $1,295 million is the same as that described earlier. Under low gas prices the benefit drops to $1,256 million, and with high gas prices it increases to $1,347 million. This relative insensitivity to gas price assumptions occurs because both the conversion resource and combined-cycle rely heavily on natural gas. With high gas prices, costs go up for both resources; however, because the conversion resource generally has a higher total efficiency than combined-cycle, it is less sensitive to changing prices and gets slightly higher benefits. The converse is true for lower gas prices.

Figure D-19. Natural Gas Price Sensitivity



It's important to note this result is only valid for comparison of conversions to a largely gas-dominated resource portfolio with the same gas price assumptions used for both conversions and combined cycle. If conversions are compared to resources with no gas price component, such as conservation or renewables, its benefits would be much more sensitive to changes in gas prices and would be significantly reduced under the high gas price assumptions. Similarly, if the gas price risk for combined-cycle development could be reduced or eliminated through fuel contracts, conversion benefits could be significantly diminished under high gas prices, but increased under a low gas price future.

<u>Effect on Emissions</u>

None of the economic results described previously has had an adjustment for differences in pollutant emissions among the alternative resource strategies. They have included only the "hard" costs for expansion and operation of the regional power system and development and operation of the conversion resource. However, because of its different fuel efficiency, combustion characteristics and potential impact on load shapes, the degree to which fuel conversions are developed can have a significant effect on the level of emissions produced in meeting regional load. This effect should be considered in making decisions about development of the fuel conversion resource.

The analysis presented here focuses only on airborne emissions. These include total suspended particulate (TSP), SO_2, NO_x, CO_2, volatile organic chemicals (VOC) and CO_2. The effects of these externalities are generally considered to be large compared to effects on land and water. There will be no difference in nuclear externalities in this study, because new nuclear resources are excluded from the resource portfolio, and fuel conversions had no impact on the operation of WNP-2, the only existing nuclear resource in the region.

The emission factors used for gas appliances and new combined-cycle are shown in Table D-4. The source for the gas appliance data is a recently produced draft report on gas appliance emissions from Lawrence Berkeley Laboratory[28] For conversion programs combining water heat and furnace conversions, energy-weighted emissions factors were developed using the data in Table D-4. The data for new combined-cycle are based on specifications for a General Electric 107FA turbine and represent a mix of emissions control technology and fuel use. It's assumed that 30 percent of new combined-cycle units will be sited in ozone non-attainment areas and will be held to the lowest achievable emissions rate (LAER) standards. The remaining 70 percent will be held to the best available control technology (BACT) standards. The turbine fuel mix includes five days per year of generation using #2 fuel oil with the remaining generation using natural gas.

Table D-4. Emission Factors (lb/mmbtu)

	TSP	SO_2	NO_x[29]	CO	VOC	CO_2
Gas Water Heater	0.0026	0	0.1032	0.0720	0.0023	126
Gas Furnace	0	0	0.1226	0.0283	0.0021	126
Combined-Cycle	0.0040	0.0032	0.0287	0.0134	0.0059	126

The net effect on system emissions from the three conversion scenarios are shown in Figures D-20 and D-21. The emission differences shown here represent

[28]Traynor, G.W. and Chang, G.M., Sept., 1993, *Pollutant Emission Factors from Residential Natural Gas Appliances: A Literature Review,* Lawrence Berkeley Laboratory for the California Institute for Energy Efficiency.

[29]NOx as NO2

system wide impacts, including all existing and new thermal resources, as well as the emissions associated with the direct use of gas. Secondary sales to the Southwest are assumed to displace combined-cycle generation and are treated as a credit. The values shown in the figures are the means for the total physical quantities produced to the year 2040, which is the end of the model time horizon.

Figure D-20.
Mean Change in Non-CO_2 Emissions

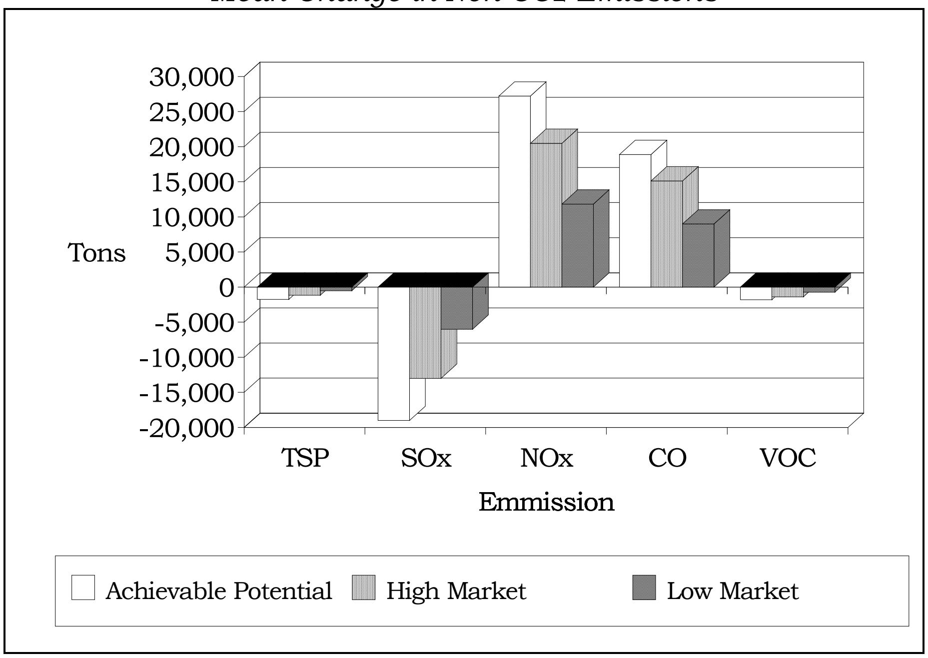
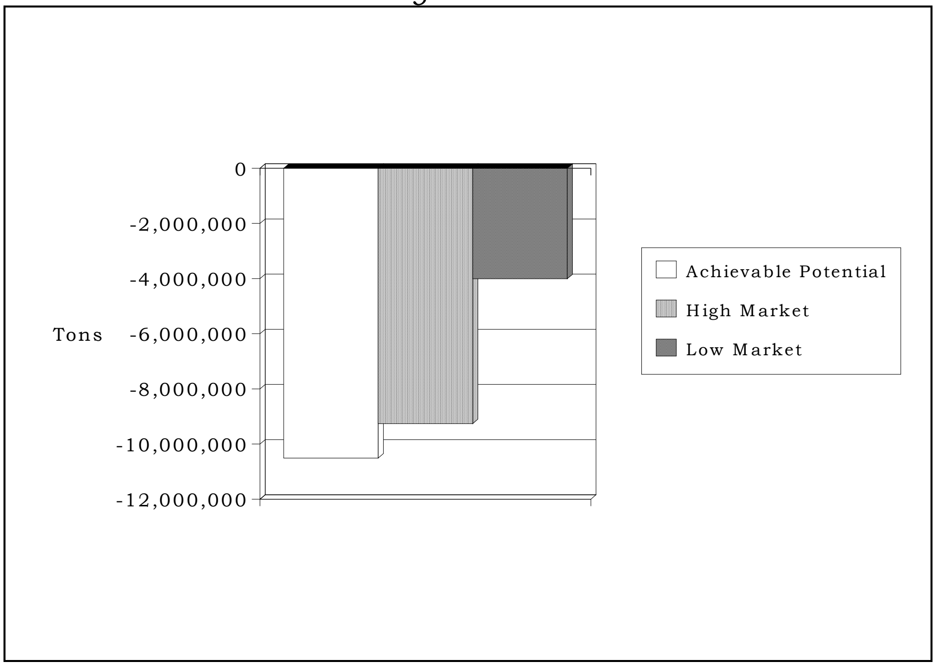


Figure D-21.
Mean Change in CO_2 Emissions

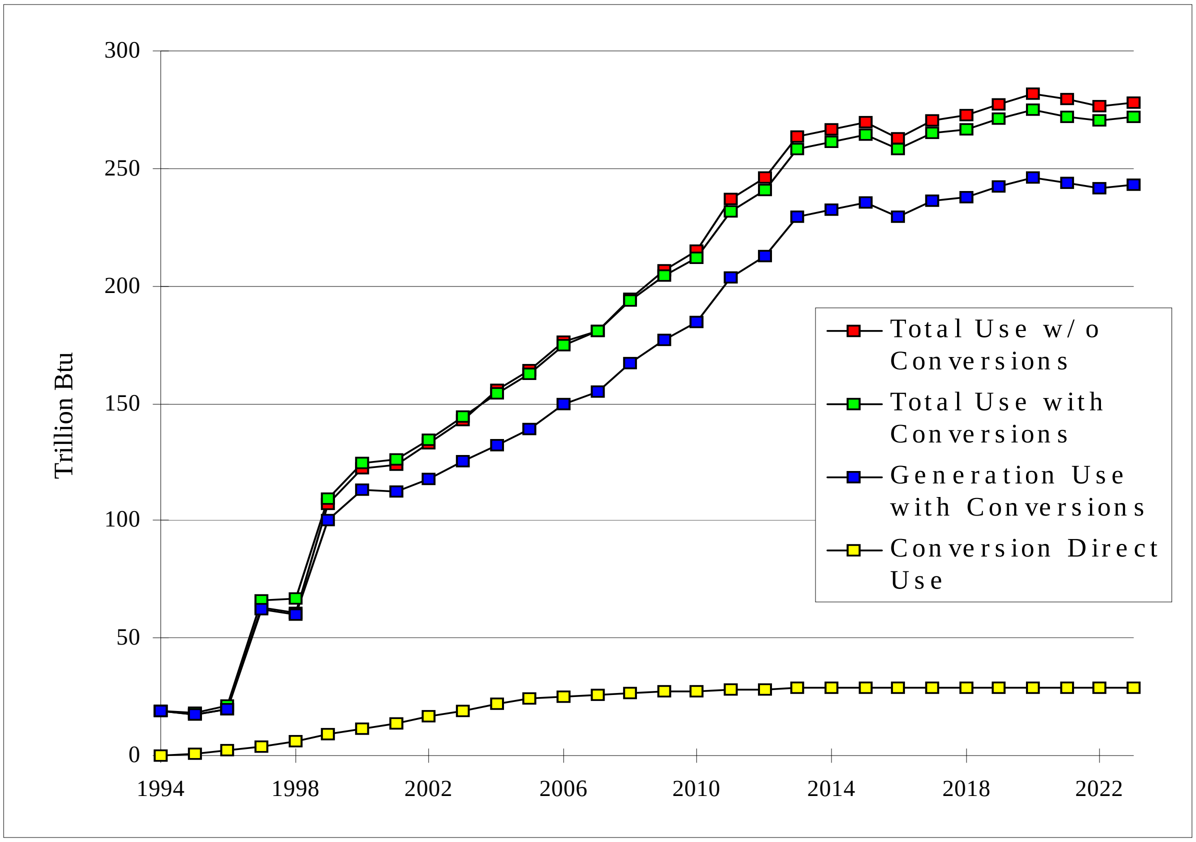


Except for SO_2, the results for non-CO_2 emissions are about what one would expect, based on the emission factors. Both NOx and CO show significant increases over the base case for all conversion scenarios, while there are only small changes in TSP and VOC. The significant decrease in SO_2 is a bit surprising because of the small differences in SO_2 emission factors between combined-cycle and conversions. However, it turns out that most of the SO_2 reduction comes from changes in the utilization of existing coal plants, primarily Centralia, Valmy and Boardman. These plants have fairly high emission rates for SO_2. Because of the strong winter electricity savings profile associated with space heat conversions, as opposed to the seasonally flat energy capability associated with new combined-cycle[30], the fuel conversion scenarios allow some differential displacement of these units. This additional displacement drives the reduction in SO_2.

[30]Because of higher efficiencies in colder temperatures, combined-cycle plants in the Northwest will exhibit higher capability in the winter. This effect is captured in the system analysis. However it is a much smaller effect than that of electrical space heating loads.

The reductions in CO_2 arise from the higher overall thermal efficiency associated with direct use of natural gas versus using it to generate electricity. The same total energy needs can be met with less use of natural gas. This is illustrated in Figure D-22. The two upper lines in the graph show mean use of

Figure D-22.
Mean Natural Gas Use



natural gas in the no conversion case versus the full achievable potential case. These include consumption of gas by both the power system and direct use for fuel conversions. The two components of use are shown as the two lower lines in the graph.

The conversion case uses about the same amount of gas early on and drops to 6 to 8 trillion Btu per year less toward the end of the timeline. The equivalent use in the short to mid-term is due to two principal causes. First, as mentioned previously, the conversion scenarios have a reduced electrical conservation potential, and therefore, will require more fuel-consuming resources for the same level of service. The second reason arises from the scheduling logic used in ISAAC. In the conversion case, more conversions are developed in the near term than combined-cycle are deferred, and the region has slightly more surplus over this time period. Due to the conservation ramp constraints, it can be necessary to overdevelop a cost-effective load reduction resource in the short-term to develop it's full potential in the long term. Toward the end of the study the load/resource balances are approximately equal and the relative gas use is more representative of the difference in thermodynamic efficiency between the two resource strategies.

While the difference in gas use is a small proportion of the total, it is enough to give rise to significant reductions in cumulative CO_2 produced over the study period. Also, keep in mind that the difference of 6-8 trillion Btu per year arises from a base of about 600 average megawatts of combined-cycle displacement, a small proportion of the total regional load met through use of gas.

Based on the system analysis studies, this 600 average megawatts of combined-cycle at the margin requires 33.5 trillion Btu per year on average. The same amount of fuel conversion consumes about 26.2 trillion Btu per year. On the margin, it takes about 22 percent less natural gas to meet demand with fuel conversions than it does for construction and operation of new high-efficiency combined-cycle. This is a smaller reduction in gas use than one would expect from a comparison of the estimated end use thermodynamic efficiencies mentioned earlier in the paper. The difference arises primarily from the displacement of combined-cycle generation in years with good water conditions.

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