

**BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION
COMMISSION**

Docket Nos. UE-060256

WUTC v. CASCADE

**RESPONSE OF PUBLIC COUNSEL TO STAFF
DATA REQUESTS**

Request No: 45
Directed to: Judith Krebs
Date Received: August 21, 2006
Date Produced: September 6, 2006
Prepared by: Jim Lazar
Witnesses: Jim Lazar

WUTC STAFF DATA REQUEST NO. 45

Re: Witness Jim Lazar

Please provide all studies that Mr. Lazar has conducted of the cost for customers on the Cascade system of using an electric heat pump to provide residential heating and the comparison of that cost with the cost of using natural gas under the proposed rate design and under the current flat rate design of Cascade. Please provide all working papers that support these calculations as well. For purposes of this request, assume that the gas furnace providing the heating requirements is a "high-efficiency" unit for the first set of calculations and then repeat assuming that the gas furnace is only 85 percent efficient.

RESPONSE:

Mr. Lazar has not prepared the requested study for Cascade. However, as a consultant to the Association of Northwest Gas Utilities in 1987-88 (of which Cascade was a member), Mr. Lazar did prepare a comparison between the net efficiency of natural gas versus electric. This study may provide insights relevant to the request, and is provided as WUTC-45 ANGU Fuel Comparison Study.pdf.

**DIRECT USE OF NATURAL GAS FOR RESIDENTIAL SPACE AND WATER HEAT
COMPARED TO
GAS-FIRED ELECTRIC GENERATION FOR HYDRO-FIRMING

THERMODYNAMIC, ECONOMIC, AND
ENVIRONMENTAL IMPACTS**

**PREPARED FOR
ASSOCIATION OF NORTHWEST GAS UTILITIES
Portland, Oregon**

**Jim Lazar
Consulting Economist
Olympia, Washington**

THE UNITED STATES OF AMERICA

1950

OFFICE OF THE UNITED STATES DISTRICT COURT

WESTERN DISTRICT OF TEXAS

AT THE CITY OF DALLAS, TEXAS

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I. INTRODUCTION

The purpose of this report is to compare direct use of natural gas for residential space and water heat to using gas for electric generation in the Pacific Northwest. The report looks at the meaning of and history of hydrofiring. It discusses recent proposals to use natural gas-fired combustion turbines to firm surplus hydropower and points out the thermodynamic, economic, and environmental advantages of the direct use of natural gas for residential end uses over the hydrofiring strategy.

This report does not evaluate the overall prudence of hydrofiring as an alternative means of providing electricity for other uses such as lighting, appliances, or motive power.

A. WHAT IS HYDROFIRMING?

Hydrofiring is a term which has been used in the Pacific Northwest for at least a decade to describe a process of supplementing hydroelectric power production with other resources during dry years when the output of the regional hydroelectric projects is reduced. The amount of power available from the hydroelectric system during the driest of recorded drought conditions is referred to as **firm** power; amounts in excess of that which is produced in wetter years is called **nonfirm** or **secondary** hydropower.

In an average year, the Northwest hydroelectric system produces about 4100 average megawatts (MWa) of electricity [33%] in excess of the amount produced in the driest period of record. This is about four times the average annual usage of the city of Seattle. This secondary energy is currently used for a variety of purposes. First, a portion

ANGU Analysis

- o Demonstrates that direct use of natural gas to heat water and space is thermodynamically, environmentally, and economically superior. It uses 20% less gas, produces 20% less carbon, and costs less than using electricity under the proposed hydrofiring/combustion turbine strategy.
- o Recognizes value of nonfirm electricity to other users.
- o Recognizes global warming (CO2) effect.
- o Considers cost.
- o Recognizes transmission system costs (gas or electric).

Recommended Actions

- o All future analyses should consider impacts on all sectors, plus economic and environmental costs.
- o Council and BPA policies should support and encourage direct natural gas use for applications for which gas is more thermodynamically, environmentally and economically efficient.

of the power supplied to certain industrial customers, including the ten regional aluminum smelters, is provided on a nonfirm basis, subject to interruption in dry years. A portion of this energy is used to displace the operation of electric generating plants with relatively high operating costs. A portion is sold to California utilities over the three interregional intertie transmission lines.

Generally, hydrofirming strategies imply a reduction in the amount of Northwest hydroelectric energy sold to California and an increase in the local utilization of that electricity in the Pacific Northwest.

Hydrofirming is expected to be cost-effective due to the relatively low price which the Northwest receives for the sale of secondary energy. Over the past five years, the price paid by California has averaged about two cents per kilowatt-hour, far less than the price -- about five to ten cents/kwh -- of obtaining power from a new generating resource. The economic theory is that it is cost-effective to pay six cents per kilowatt-hour for power from resources with high operating costs, such as combustion turbines, in rare, but inevitable dry years, as long as in most years the region can rely on secondary energy which has an opportunity cost -- foregone sales to California -- of about two cents per kilowatt-hour. The Council staff suggested that hydro power might not be available one year out of three. The report uses this assumption even though it may not accurately reflect the true frequency or duration of secondary hydro availability.

1 year in 3	Combustion Turbines	6 cents/kwh
2 years in 3	Secondary Hydro	2 cents/kwh
Average Cost of Firmed Hydro:		3.3 cents/kwh
Cost of Power from New Coal Plant:		5.0 cents/kwh

There are numerous ways to supplement the secondary power produced in the hydro system in order to make it a resource which can be relied on in regional power planning processes. The most commonly discussed method is to construct combustion turbine generators fueled with natural gas or #2 distillate fuel oil, and operate these fossil-fired plants in dry years when hydroelectric power output is limited. A variety of approaches to hydrofirming are listed below:

COMBUSTION TURBINES: A combustion turbine is basically a jet engine connected to an electric generator. Oil and/or natural gas is burned in combustion turbine-generating plants in dry years to replace the electricity which is normally available from hydroelectric sources.

INTERRUPTIBILITY: Special contracts are established with large industrial customers which give those customers discounts on their power in exchange for the right to curtail such usage in dry years.

IRRIGATION REDUCTIONS: Special contracts are established with farmers holding surface water rights for irrigation to encourage them to either substitute crops with

lower water requirements during dry years or cease production altogether. The water normally diverted from the river for irrigation purposes is left in the river during dry years and generates power at existing hydroelectric dams. This approach may require new legal and contractual arrangements.¹

OUT-OF-REGION PURCHASE: Contracts are entered into with electric utilities in the desert southwest or in California to supply power during particularly dry years. It would be shipped north via the interregional intertie transmission lines.

VOLUNTARY CURTAILMENT: In 1977 the Pacific Northwest faced the most severely limited stream flows since World War II. The interruptible portion of the aluminum company load was curtailed, but shortages still loomed. Northwest political and energy leaders urged the public to voluntarily reduce electric usage by lowering thermostats, eliminating outdoor lighting, and using other short-term measures. Local utilities saved approximately 5% of total usage¹, an amount which would equal about 750 MWh nationwide.

RATE DESIGN: In 1985, a "wet" year, the Bonneville Power Administration (BPA, or Bonneville) offered a special discounted rate to its utility customers designed to encourage short-run increases in usage. This was often referred to as a "chainsaw" rate, since a major focus of the program was to encourage electric heat customers who had installed wood heating equipment to resume using electric heat. The opposite technique could be used during a drought. The space heat rate could be increased to encourage customers with wood heat or other alternative fuel capability to reduce electricity consumption.

This report addresses the thermodynamics, economics, and global warming impacts of the use of combustion turbine generators, particularly with respect to producing power in order to serve residential space and water heater loads. The report does not evaluate the other options listed above.

B. STATUS OF HYDROFIRMING IN THE NORTHWEST

Presently virtually all Northwest hydroelectric power is used, either in the Northwest or in California. Due to the construction of large storage reservoirs in the upper reaches of the Columbia River in Canada and Montana, very little energy is "spilled" over the top of dams.

Two of the hydrofarming strategies identified above are presently in place. These are interruptibility and combustion turbines.

¹ See: Hamilton, et. al., Interruptible Water Markets in the Pacific Northwest, American Journal of Agricultural Economics, Vol. 71, No. 1, February, 1989.

First, the "top quartile" of service to the direct service industrial customers is interruptible under drought conditions. This provides BPA with the flexibility to reduce load by approximately 900 MWa. The last actual curtailment and reduction in output at the aluminum plants due to drought was in 1977. Bonneville has frequently "curtailed" service under the interruptible contracts, and then obtained substitute power to actually keep the plants operating.

Second, some combustion turbines are already included in regional electric resource plans to be used for hydrofiring. Presently there are approximately 1,600 MW of oil and gas fired generating plants installed in the Pacific Northwest. If fully utilized under drought conditions at the Council's estimated 83% equivalent availability factor, these units could provide nearly 1,400 MW of firm energy, assuming that fuel was available. A complete list of these is contained in Appendix A to this report.

Of these, only about 600 mw, less than half of the available total, are "planned" to be used as hydrofiring resources under drought conditions to supply regional electric power needs, and would produce about 500 MWa if actually used. Portland General Electric includes the Beaver combined-cycle project [545 mw] as a firm energy resource, and each of the utilities receiving energy from BPA under the WPPSS #3 Exchange Agreement include among their firm energy resources sufficient production from their combustion turbines to provide return energy to BPA.

Puget Sound Power and Light Company, with approximately 700 mw of combustion turbines plus the 86 mw Shuffleton steam plant, does not "plan" on using its oil/gas fired plants as hydrofiring energy resources to supplement the hydro system in dry years. However, as a practical matter, Puget's resource plans clearly imply an expectation that these resources will be relied upon as necessary in dry years. For 1991, for example, Puget forecasts a firm energy deficit of 77 MWa, rising to 626 MWa by 1997. Puget clearly anticipates being able to use its oil/gas fired plants if cheaper sources of electricity are not available, but has not made a formal declaration of this intent. If Puget's existing combustion turbines and Shuffleton were counted as hydrofiring resources, they could be expected to produce about 600 MWa of additional energy.

In summary, the Northwest currently plans on approximately 500 MW of generation from hydrofiring generation equipment "declared" as firm energy resources and approximately an additional 1,100 MW of installed units available, but as yet not included as firm energy resources under drought conditions. Taken together with the interruptibility provisions of the direct service industrial contracts, and the benefits of voluntary curtailment demonstrated in 1977, the region has in excess of 2,000 MW of hydrofiring capability in place at the present time.

Oil/gas generators declared as firm resources:	500
Existing oil/gas generators not yet declared:	900
DSI Top Quartile	800
Total	2,200

II. ADDITIONAL HYDROFIRMING FOR SPACE AND WATER HEATING USES

Since the preparation of the 1983 Northwest Electric Conservation and Power Plan (Plan), the Northwest Power Planning Council (NWPPC, or Council) has included hydrofirming as a resource to be acquired prior to construction of new coal-fired powerplants or similar conventional baseload generating resources. In the 1983 Plan, 1,050 Mwa of secondary hydro was presumed to be firmed with combustion turbines. In the 1986 Plan, 714 Mwa of secondary hydro was presumed to be firmed.

This report looks only at the use of additional hydrofirming using combustion turbines as a source of supply for residential space and water heating. Other methods or applications of hydrofirming are not evaluated.

A. 1990 Proposal by NWPPC Staff

The Northwest Power Planning Council Staff has studied the construction of additional combustion turbines or combined cycle combustion turbines to supplement additional Northwest secondary hydroelectric power for space and water heating end uses. As part of its preparation of comments to the Bonneville Power Administration on the Draft 1990 Resource Program, the NWPPC staff produced a diagram showing the theoretical use of additional combustion turbines as a source of energy to serve residential space and water heating loads. The diagram sought to convey a message that hydroelectric power firmed with gas-fired combustion turbines could actually provide more delivered residential space and water heating BTUs than a comparable amount of natural gas burned in natural gas furnaces and water heaters. The NWPPC diagram appears as Figure 1.

The approach used by the NWPPC staff assumes that secondary hydroelectric power would be used two years out of three to serve residential space and water heating needs. Combustion turbine generators, fueled with natural gas at 40% efficiency, would be used during the one - in - three years "drought" conditions to produce the electricity needed to serve these requirements. The NWPPC Staff Study assumed that the electricity would be used in electric heat pumps for space heating, at 200% efficiency, and in electric resistance water heaters for water heating, at 90% efficiency. The direct usage of natural gas was assumed to be in furnaces at 80% efficiency and water heaters with 60% efficiency. All ducted heating systems -- both electric heat pumps and gas furnaces -- were assumed to lose 25% of the heat produced as a result of ducting and pressurization losses.

The NWPPC Staff study did not reach explicit conclusions about the amount of natural gas which would be "saved" under the combustion turbine/secondary hydro scenario put forth, but the hydrofirming option was clearly presented as a reduction in natural gas usage compared with direct use of natural gas in furnaces and water heaters.

This consultant has published previous evaluations of the cost-effectiveness of hydrofirming as an alternative to construction of baseload generating projects. The consultant was requested to review the NWPPC Staff Study and to determine if additional factors were appropriate to the comparison contained in the NWPPC Staff Study. This

report is the result of that inquiry.

B. Factors Omitted from NWPPC Staff Study

The NWPPC Staff Study clearly omits three crucial elements to an analysis of the use of firming hydropower to serve space and water heating loads. First, the study omits any consideration of the impact on California utilities and their use of fossil fuels as a result of reduced exports of secondary hydroelectric power from the Northwest. Second, the NWPPC study eliminates any consideration of cost. When these factors are included, the desirability of the strategy outlined in the NWPPC Staff Study becomes very questionable. Finally, when environmental costs are considered as required by the Pacific Northwest Electric Power Planning and Conservation Act, the combustion turbine/heat pump strategy becomes even less attractive.

1. Thermodynamic Efficiency

The NWPPC Staff Study [Figure 1] purports to show that a 1000 BTU input of natural gas to a direct application produces 600 BTU of usable space or water heat. The same amount of natural gas employed in a hydrofirming strategy in conjunction with secondary hydropower produces 1000 BTU of water heat or 1,600 BTU of space heat. On this basis, the NWPPC Staff Study concludes that use of the secondary hydroelectric power together with natural gas combustion turbines is thermodynamically preferable to providing the same space and water heating end uses with direct application of natural gas.

The NWPPC analysis is accurate with respect to the Pacific Northwest, but entirely ignores the fact that the secondary hydro would be available for export to California absent the hydrofirming strategy. California would have to replace this source of supply of electricity if the secondary hydroelectric power were used in the Pacific Northwest in a hydrofirming strategy. The fuel requirements needed to replace this electricity in California are discussed in c. below.

a. Amount of Electricity Needed to Serve the Space and Water Heating Loads

This study looks at the use of electric heat pumps and water heaters in a hydrofirming strategy as an alternative to the direct use of natural gas for space and water heating in a typical newly constructed Northwest home. Figures 2 and 3 show a more complete presentation of the effect of providing space and water heating for one Northwest house with electricity derived from firming hydropower versus providing space and water heating for the same house with natural gas and exporting available secondary hydropower.

In both cases, the end-use requirements for space and water heating are identical, reflecting an assumption that the building shells and heat loss are identical, and the hot water usage for both is identical. Because of these assumptions, the building shells are

presumed to have identical cost. The space heating end-use requirement of 20.4 million BTUs per year is taken from a 1987 NWPPC study.² The water heating end use of 14.7 million BTUs per year is taken from a 1989 Washington State Energy Office study.³

Figure 2 displays the effect of providing this space and water heating service with electricity. A total of 9738 kilowatt-hours of electricity is required to be produced within the region each year to serve these end uses. Of this amount, the Council staff estimates that 10% is dissipated in line losses and 8764 kwh is delivered to the subject home.

Of the amount delivered to the home, 4779 kwh is utilized in the water heater at 90% efficiency. The end result for water heating is shown below:

4779 kwh x 3413 BTU/kwh =
16.3 million BTU @ 90% efficiency =
14.7 million BTU of hot water

The remaining electricity, 3985 kwh is used in an electric heat pump which has an annual coefficient of performance of 2.0, meaning that 2 units of heat is produced for each unit of electricity used. 25% of this heat is presumed to be dissipated due to ducting and pressurization losses. The end result for space heating is shown below:

3985 kwh x 3413 BTU/kwh =
13.6 million BTU @ 200% efficiency =
27.2 million BTU warm air
Less 25% ducting and pressurization losses =
20.4 million BTU delivered to heated space

The total amount of electricity required each year, therefore, is 9738 kwh, consisting of 4779 kwh for water heating, 3985 kwh for space heating, and 974 kwh for transmission and distribution losses.

b. Natural Gas Requirements to Firm Hydropower in Northwest Two Years out of Three.

Under the hydrofiring option in Figure 2, 9738 kwh of secondary hydro is available within the Pacific Northwest in two years out of three. In the third "drought" year, the same amount of electricity must be produced by using natural gas at a power plant in the region. The NWPPC Staff Study ascribed a 40% efficiency to the gas-fired power plant.

At 40% efficiency of fuel conversion, an input of 8532 BTU of natural gas would be required to produce each kwh required to be generated in the drought years. The total natural gas requirement for generation is therefore 83.1 million BTUs, or 831 therms of natural gas. This conversion is as follows:

83.1 million BTU @ 40% efficiency =
33.24 million BTU (electric) / 3413 BTU/kwh =
9738 kwh

Thus, the natural gas requirements within the Pacific Northwest amount to 831 therms during the drought years, which the NWPPC Staff Study assumes to occur one year out of three.

c. Natural Gas Requirements in California to Replace Electricity Not Received from Northwest Due to Hydrofiring.

The basic choice facing the region is to either use our secondary hydropower in the region in some sort of hydrofiring strategy, or to make that secondary hydropower available for export to California. Figure 3 shows the amount of secondary hydropower available in the Northwest which the hydrofiring option would use to provide space and water heat for the subject house, but which otherwise could be delivered in California.

Since the hydrofiring strategy involves using 9738 kwh of secondary hydropower in the Northwest during the non-drought years which occur two years out of three, less electricity is available for export to California than under a non-hydrofiring strategy. However, the intertie lines to California are limited in capacity, and there are occasions when the available surplus hydroelectric production in the Northwest exceeds the available markets for that surplus, and the unusable surplus is "spilled" over the top of the dam. Current management of the Columbia River hydroelectric system has greatly reduced the probability of spill, but it does occasionally occur.

If a hydrofiring strategy were employed to serve space and water heating loads in the Northwest, this would add another market to the existing uses for surplus hydropower (sales to direct service industries and to California utilities). Because of the increased demand for more surplus, the amount of electricity generated would not be constrained by transmission capacity and less water would have to be spilled. It would all be used to generate power. If surplus hydro is not used in the Northwest for heating water and space, the system will generate only what can be sold to the DSIs and exported to California over the interties. So about 10% of available water would have to be spilled. This estimate has been accepted by the NWPPC Staff as a conservative estimate; the amount which would actually be spilled could be far less than 10%.

Absent a hydrofiring strategy, 9738 kwh of secondary hydro would not be used in the Northwest in the two years out of three that it is available. If 10% of this were spilled, a total of 8764 kwh would be available for export to California. The intertie transmission lines are efficient, but long, and approximately 10% of the energy which is exported is lost before it reaches California. Therefore, absent a hydrofiring strategy, California would receive 7888 kwh of Northwest secondary hydro two years out of three. If 9738 kwh of secondary hydropower were used in the Northwest in a hydrofiring strategy, California would need to replace not the entire 9738 kwh, but only the 7888 kwh which would actually be expected to reach California absent such hydrofiring.

The California utilities have a number of oil and gas fired powerplants available to them which they currently use in years when secondary hydropower is not available from the Pacific Northwest. In that sense, of course, the existing Northwest secondary hydropower is already being "firmed," but in California rather than in this region. Assuming the efficiency of the California powerplants is the same 40% assumed for the Northwest, 673 therms of natural gas would be required to replace the 7888 kwh of Northwest secondary hydropower which California would cease to receive under a hydrofiring strategy, as shown below:

67.3 million BTUs natural gas @ 40% efficiency =
26.9 million BTUs electricity @ 3413 BTU/kwh =
7888 kwh electricity produced in California.

The assumption of 40% efficiency in California is favorable to the argument set forth by the NWPPC Staff. While California has some combined cycle gas-fired generating plants capable of operating at 40% efficiency, the majority of the California generating capacity which would be used to replace this lost energy which is currently in place is less efficient -- in the 30% to 35% efficiency range.

If the California utilities are required to use generating plants which are less efficient than the assumed 40%, the natural gas usage would be greater than 673 therms/year. If a portion of the electricity could be produced through cogeneration or other highly efficient conversion processes, the usage could be less than 673 therms/year to replace the unavailable Northwest secondary hydropower.

If California decided to reduce reliance on natural gas, the replacement kilowatt-hours could be produced with coal at newly constructed remote generating stations. The efficiency would be lower than the 40% assumed here, line losses would be incurred requiring additional fuel use, and the total fuel burned would be considerably greater.

d. Total Natural Gas Required on West Coast Under Hydrofiring Strategy.

Under the hydrofiring strategy proposed in the NWPPC Staff Study, the total natural gas required on the West Coast in order to provide the space and water heat for one Northwest home and to provide 7888 kwh of electricity in California in two years out of three would be approximately 726 therms/year, as shown below:

Northwest Combustion Turbines 1/3 years:	831 therms
California Generation 2/3 years:	673 therms

Average Annual Usage: 726 therms

e. Natural Gas Requirements to Provide Space and Water Heating Through Direct Application

Figure 3 shows the amount of natural gas which would be required to provide direct space and water heating to one Northwest house with the same end-use of space heat and hot water as used in the electric example.

For each house in the diagram a total of 600 therms of natural gas enters the gas distribution system each year. Of this, about 2.25% is consumed as compressor fuel and in line losses associated with the gas distribution system. 585 therms, or 58.5 million BTUs, reaches the subject house.

Of this amount, 245 therms is delivered to the water heater, which operates at an assumed 60% efficiency level, the same efficiency assumed by the NWPPC Staff Study.⁶ The end result is as shown below:

24.5 million BTU @ 60% efficient water heater =
14.7 million BTU of hot water

The remaining 340 therms of gas is delivered to the furnace, which operates at 80% efficiency, but 25% of this heat is lost due to ducting and pressurization, as assumed by the NWPPC Staff Study. The end result is as shown below:

34.0 million BTU @ 80% efficient furnace =
27.2 million BTU delivered to ducting @ 75% efficiency =
20.4 million BTU delivered to heated space.

This end result, 14.7 million BTUs delivered as hot water, plus 20.4 million BTUs delivered as heated air, is exactly the same as the end result as that set forth above in the hydrofiring example using electric heat pumps and water heaters. This alternative, however, does not use Northwest secondary hydropower within the region, and therefore the amount used in the hydrofiring example -- 9738 kwh in two years out of three -- is available for export. As described above, this amount of unused secondary hydropower would provide a net of 7888 kwh delivered in California two years out of three. Total natural gas consumption in the Northwest and California to reach the identical result would be 600 therms/year under the direct application of gas alternative.

f. Summary of Thermodynamic Results

Under a hydrofiring strategy, an average of 726 therms of gas per year would be needed in order to provide space heat and hot water under the hydrofiring / heat pump option and to provide 7888 kwh in two out of three years in California. Only 600 therms/year would be required under the direct gas space and water heating option to reach the same result. From a thermodynamic perspective, direct space and water heating is approximately 20% more efficient for the West Coast overall.

The same hydrofiring strategy was also evaluated by the consultant under the assumption that, instead of heat pumps, new homes might be built to the more stringent electric resistance heat model conservation standards and use zonal electric heat. This lowers the cost of the electric alternative, but electric heat fueled with firmed hydro

remains both more expensive and requires more gas than the direct gas space and water heating option.

2. System/Capital Cost

The second issue neglected by the NWPPC Staff Study is the cost of the two alternative scenarios. Figure 4 shows the costs of the various components which are needed to provide the end-use space and water heating requirements of the subject house used in this example.

a. Natural Gas Space and Water Heating System Costs

Beginning with the gas space and water heating option, the existing gas transmission system would have to be connected to each house. The cost of such a service extension averages about \$550 per house.⁷

A natural gas furnace and ducting system would be required. The NWPPC Staff estimated the cost of such a system at \$1895.⁸ Finally, a natural gas water heater would be required; WSEO estimated the equipment costs of a gas water heater to be \$250.⁹ Based upon recent direct experience, the Author has determined the installed cost to be approximately \$350.

Thus, the total installed cost of the natural gas space and water heating system is as follows:

Service extension:	\$550
Furnace and ducting:	\$1,895
Water Heater:	\$350
Total System Cost:	\$2,795

Note: Where central air conditioning is required, \$1,200 should be added to the cost.

b. Electric System Costs for Hydrofiring

The equipment required to provide electric space and water heat service is more extensive than for direct gas heating, due to the need to convert gas to electricity, and electricity into heat at the end use.

(1) Combustion Turbines

The first component required is the generating plant. The NWPPC Staff Study did not indicate whether single cycle or combined cycle combustion turbines would be used, but did specify an efficiency of 40%. Since combined cycle plants have greater fuel

efficiency, but are more expensive to construct, it is important to identify the assumed equipment type.¹⁰

According to NWPPC data, combined cycle combustion turbines have a fuel conversion efficiency of 35%¹¹ to 45%¹². The actual reported efficiency of the existing Beaver combined-cycle combustion turbine is 39%. The 40% efficiency assumed in the NWPPC Staff Study is consistent with expected performance of combined cycle combustion turbines.

The same NWPPC sources used for the assumed efficiency of combined cycle combustion show efficiencies for single cycle combustion turbines of 30%-33%. The 40% efficiency assumed in the NWPPC Staff Study is not consistent with expected performance of single cycle combustion turbines.¹³ Therefore this study assumes the use of combined cycle combustion turbines in order to achieve the assumed 40% efficiency.

According to the NWPPC, combined cycle combustion turbines have a cost of \$620 - \$714 per kilowatt, and equivalent availability [operating reliability] of 83%.¹⁴ Therefore, in order to produce 9738 kwh of electricity in a year, a total investment of at least \$830 in combined cycle combustion turbines would be required, as shown below:

Annual generation = 9738 kwh / 8760 hrs/year =
1.11 average kw @ 83% equivalent availability =
1.34 kw of capacity required @ \$620/kw =
\$830 investment cost in combustion turbines per house

(2) Distribution Plant

It is assumed that every house will have electric service, and therefore the choice of electric space and water heat does not require that an additional electric service connection be installed. The decision to install electric space and water heat does impose a requirement that the electric utility size distribution substations, lines, and transformers to serve a higher peak load.

Annual space heating usage of approximately 4000 kilowatt-hours in a heat pump imposes an additional peak hour demand on the electric distribution system of approximately 4-6 kilowatts on a class diversified basis. Electric water heater usage imposes an additional contribution to peak demand of 1 - 1.5 kw. Thus additional distribution capacity of at least 5 kilowatts must be available to serve each customer choosing electric space and water heat rather than natural gas space and water heat.

Based upon numerous electric cost of service analyses reviewed by the Author for Northwest and extra-regional utilities, the marginal investment in distribution lines and transformers required to serve additional peak demands is estimated at \$25 to \$100 per kilowatt. Thus, the required incremental distribution plant investment to serve the electric space and water heat requirements of a heat-pump/electric water heater home built to the model conservation standards is estimated at \$125 to \$500.

Transmission costs are not considered in this analysis. If the house were to be built in a transmission-constrained area such as Western Washington [the area within the Northwest currently experiencing the highest level of growth], there may also be a transmission investment component associated with providing electric space and water heating service. The author notes that the Bonneville Power Administration is considering direct application of natural gas for residential water heating as a potential means to mitigate the Puget Sound transmission deficiency.

(3) Heating Equipment

The NWPPC Staff Study assumed the use of an electric heat pump with 200% conversion efficiency as a part of the thermodynamic analysis, but did not include cost in its study. Heat pumps are expensive. This analysis relies on the estimated cost of a heat pump and ducting system used in the NWPPC 1987 Heating Cost Study, a cost of \$4,110 per house.

The cost of an electric water heater is approximately the same as that for a gas water heater.¹⁵ Therefore, this analysis also assumes \$350 for an electric water heater.

(4) Total Investment Required for Hydrofiring / Electric Space and Water Heat Option

The total investment cost for the electric hydrofiring / heat pump option is substantially larger than that required for direct natural gas space and water heating as shown below:

Heat Pump and Ducting	\$4,110
Water Heater	\$ 350
Incremental Peak Distribution Capacity	\$ 125 -
	\$ 500
Combustion Turbine:	\$ 830
Total System Cost:	\$5,415 -
	\$5,790

c. Cost Summary

Therefore, the natural gas space and water heating system costs approximately half as much as the equipment required to provide the same level of space and water heat under the hydrofiring / heat pump option. The option of using zonal electric heat instead of the heat pump assumed in the NWPPC Staff Study was also evaluated, but did not change the conclusion that the investment required is lower if gas is used directly for space and water heating.

The life-cycle fuel costs of each option were not computed, due to the wide range

of possible assumptions regarding the future price of natural gas. Since the direct use of natural gas for space and water heating uses approximately 20% less gas than the hydrofiring option coupled with California generation of replacement energy, the gas space and water heating option can be expected to have life-cycle fuel costs approximately 20% below the hydrofiring option.

3. Environmental Impacts

The combustion of any fuel in any application creates adverse environmental impacts. Natural gas is an environmentally preferable fuel to more carboniferous alternatives, including oil, coal, and wood, but still produces carbon dioxide vapor and trace amounts of other pollutants. This discussion focuses on the carbon dioxide emissions from the alternatives, which is the primary target of current efforts to control global climatic change.

Combustion of natural gas produces approximately 118 pounds of carbon dioxide per million BTU of heat produced. Using this ratio, it is straightforward to compare the carbon dioxide emissions from the two strategies:

CARBON DIOXIDE EMISSIONS FROM RESOURCE STRATEGIES

Hydrofiring Option:	8567 lbs/year/house
Gas space and water heat:	7080 lbs/year/house

If a portion of the California generation could be produced with cogeneration, the amount of carbon dioxide produced under the hydrofiring option would be reduced. If single cycle combustion turbines, coal, or oil were used, the carbon dioxide emissions from the hydrofiring option would be increased. In addition, if coal, oil, refuse-derived fuels, or other alternatives to natural gas were used, emissions of sulphur dioxide, oxides of nitrogen, and other pollutants would be produced.

III. CONCLUSIONS AND RECOMMENDATIONS

The hydrofiring strategy for providing residential space and water heat depicted by the Northwest Power Planning Council Staff in Figure 1 does not offer the thermodynamic benefits which it suggests would result from supplementing Northwest hydropower with natural gas derived electricity. In addition, the NWPPC Staff Study ignored cost considerations and environmental impacts. The direct use of natural gas for residential space and water heating would use approximately 20% less natural gas, 50% less capital, and produce 20% less carbon dioxide than the hydrofiring / heat pump option suggested by the NWPPC Staff Study. The direct application of natural gas to residential space and water heating appears to be thermodynamically, economically, and environmentally more efficient than the use of natural gas for hydrofiring in the manner set forth by the NWPPC Staff in Figure 1.

This conclusion does not suggest that hydrofiring is an inappropriate way to produce electricity, nor even that the use of natural gas as a fuel to support hydrofiring strategies should not be considered. The following alternatives to the hydrofiring strategy presented by the NWPPC staff are appropriate to explore:

- 1) Use of natural gas to provide space and water heating energy to loads now using electric resistance heat or heat pumps and for other applications where the end-use efficiency of direct use of natural gas is 50% or higher.
- 2) Use of non-combustion methods of hydrofiring, such as additional interruptibility and reduced diversions of water from the hydro system in drought years.
- 3) Use of temporary rate incentives designed to encourage customers to use less electricity -- whether through conservation, curtailment, or fuel substitution -- in drought conditions.
- 4) Use of natural gas as a hydrofiring fuel to serve end uses which are most efficiently served with electricity.

Hydrofiring can be a useful and economic strategy for the Pacific Northwest. It should not be construed to consist solely of burning natural gas in combustion turbines. From a resource, cost and environmental perspective, hydrofiring with gas-fired combustion turbines should not be considered a viable alternative to the direct application of fuels such as natural gas to end uses.

V. REFERENCES AND NOTES

1. See: Hamilton, et. al., Interruptible Water Markets in the Pacific Northwest, American Journal of Agricultural Economics, Vol. 71, No. 1, February, 1989.
2. Heating Cost Study, Northwest Power Planning Council, 1987, Page 2
3. Analysis of Consumer and Marginal Cost for Electric and Natural Gas Space and Water Heat in Single Family Residences in Puget Sound Power and Light Company Service Territory, Washington State Energy Office, September, 1989, P. 8
4. Conversation with Jim Litchfield, Director of Power Planning, February 9, 1990.
5. The average efficiency of fossil-fired units currently in "standby reserve" in California is about 30% [California Energy Commission 1988 Electricity Report and FERC Form 1 Reports for So. Calif Edison and Pacific Gas and Electric]; this study assumes 40% efficiency on the assumption that at least a portion of the foregone

- electricity would ultimately be produced at combined cycle plants or using cogeneration. Appendix B shows the calculation of gas requirements and CO₂ emissions if existing standby plants are used.
6. Available gas water heaters which meet existing energy codes range in efficiency from 53% [ASHRAE 90-80 standard] to as much as 83% [The Most Energy Efficient Appliances, American Council for an Energy Efficient Economy, 1988 Edition].
 7. WSEO, supra, P. 14
 8. NWPPC 1987 Heating Cost Study, appendix pages not numbered
 9. WSEO, supra, P. 10
 10. Thermal Resources Data Base, Pacific Northwest Utilities Conference Committee, October, 1984, P. 18
 11. Northwest Conservation and Electric Power Plan, 1986, Vol. 2, P. 6-H-1
 12. 1989 Supplement to the 1986 Northwest Conservation and Electric Power Plan, Northwest Power Planning Council, Volume 2, P. 4-38
 13. A single cycle combustion turbine is simply a jet engine attached to a generator. A combined cycle combustion turbine uses the waste gases of the jet engine to operate a heat recovery boiler, and the boiler steam is used to drive a second generator, improving the efficiency of fuel conversion.
 14. NWPPC 1989 Supplement, supra, P. 4-38, 4-40
 15. WSEO, supra, P. 10

Figure 1 -- NWPPC Staff Study

INPUT 1 CUBIC FOOT OF NATURAL GAS
(1000 BTUs)

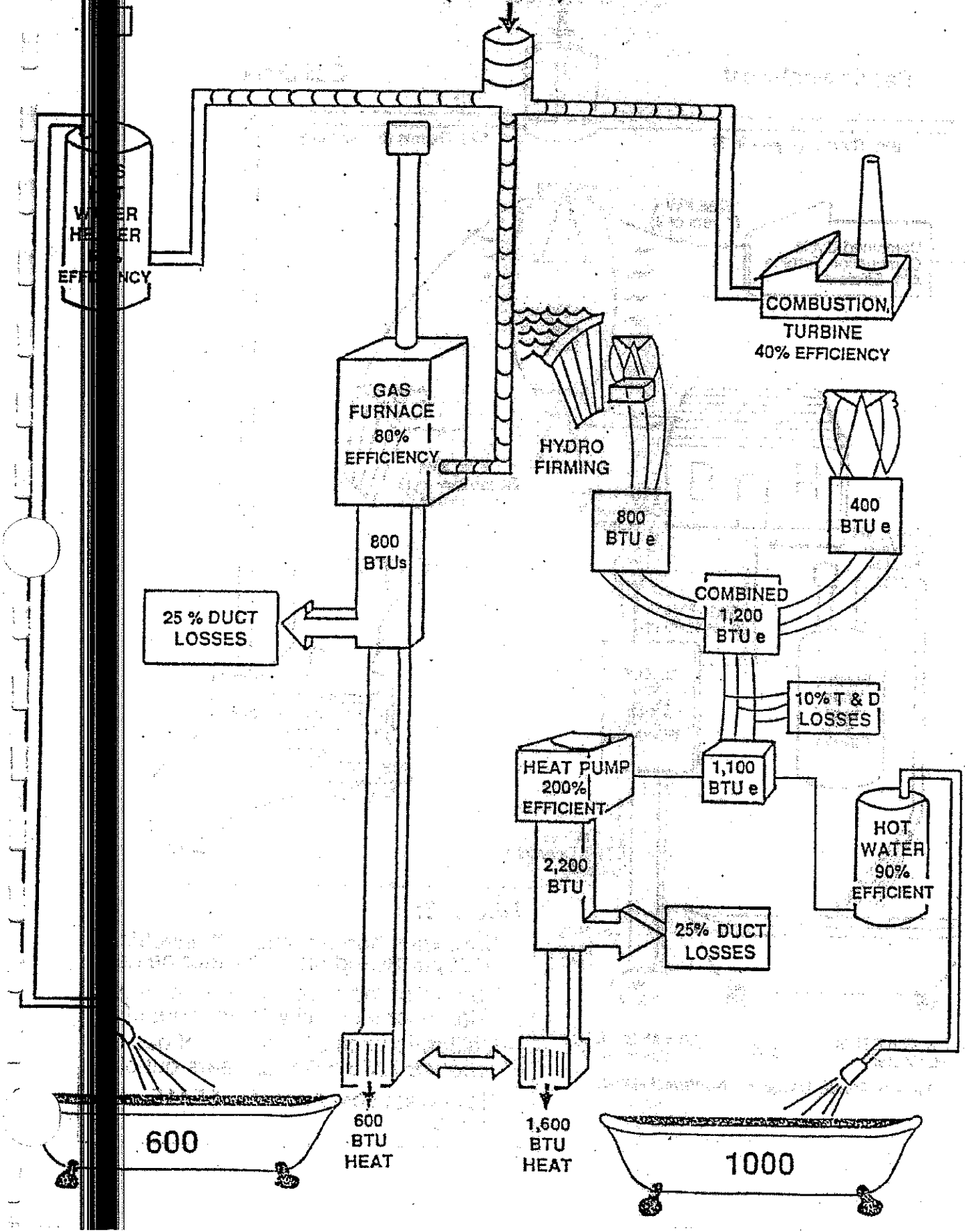
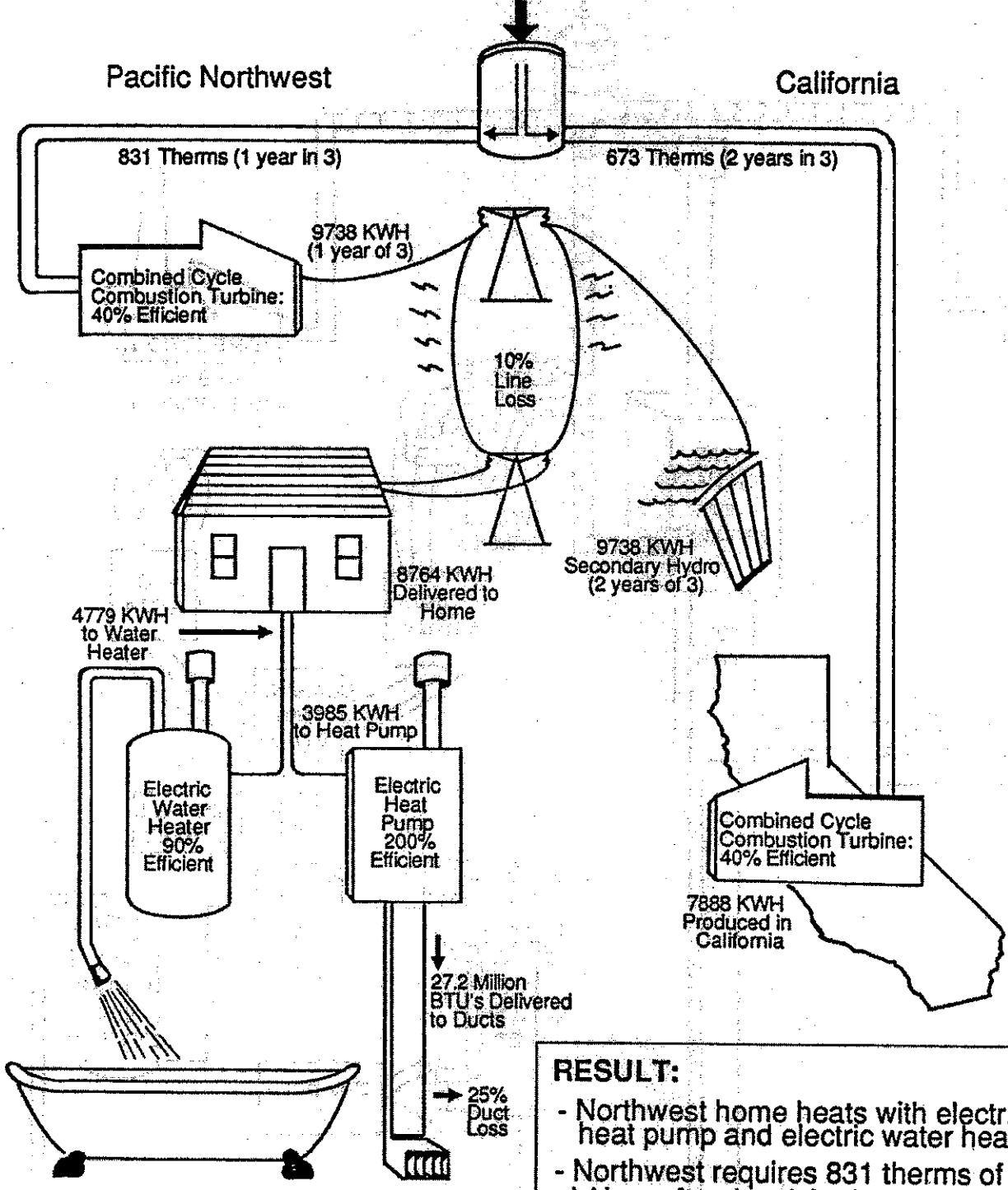


Figure 2

Electric Heat Pump and Hot Water Option / Use Surplus Hydro in Northwest

Average of 726 Therms / Year
of Natural Gas



14.7 Million BTU's Hot Water and 20.4 Million BTU's Space Heat
(Average Annual Usage Per Northwest Home)

RESULT:

- Northwest home heats with electric heat pump and electric water heater
- Northwest requires 831 therms of gas \ Home for electricity (1 year out of 3)
- California uses 673 therms of gas to produce 7888 KWH (2 years out of 3)
- Northwest cost / home = \$5415 - \$5790

Figure 3

Gas Space & Water Heat Option / Sell Surplus Hydro to California

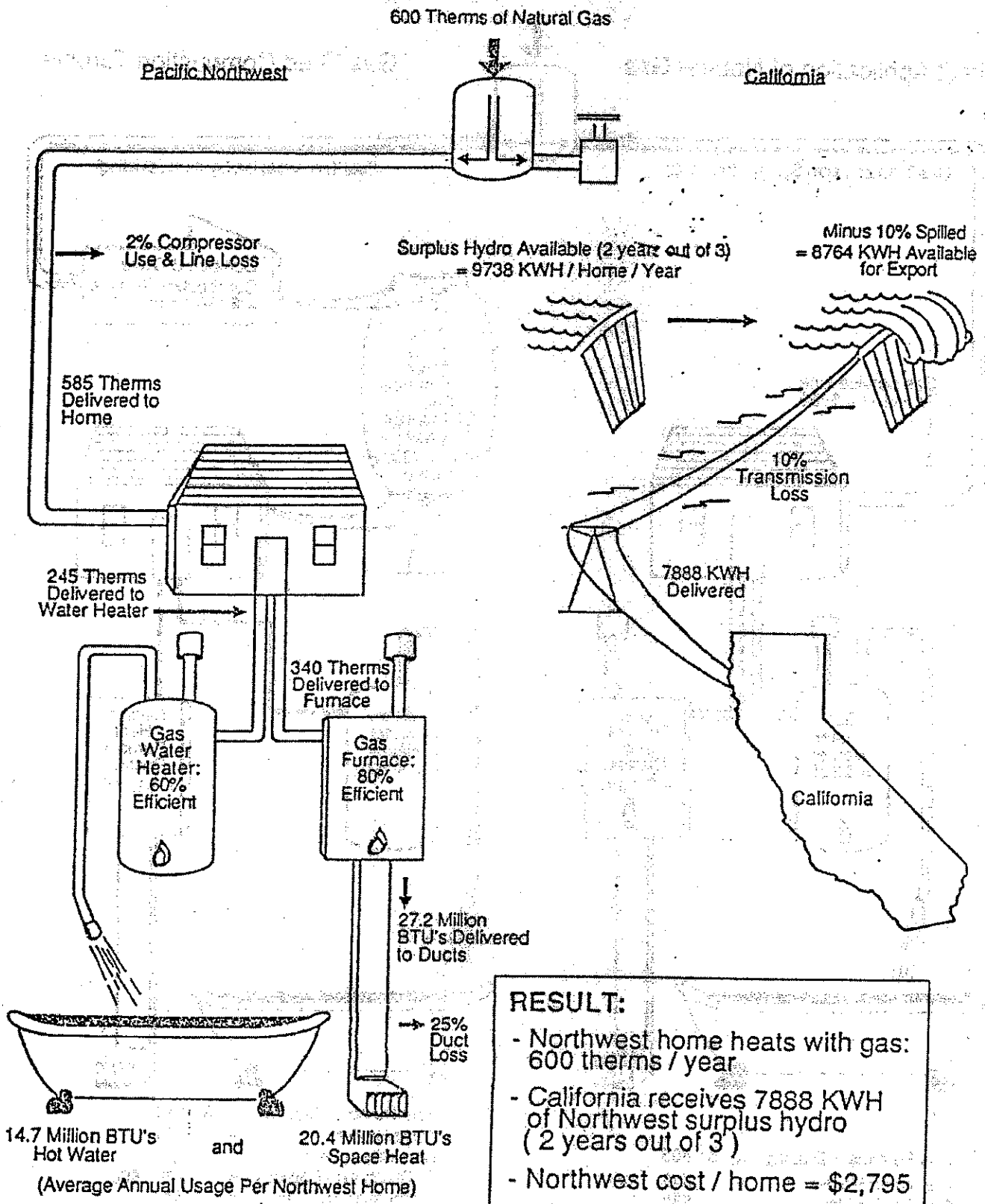
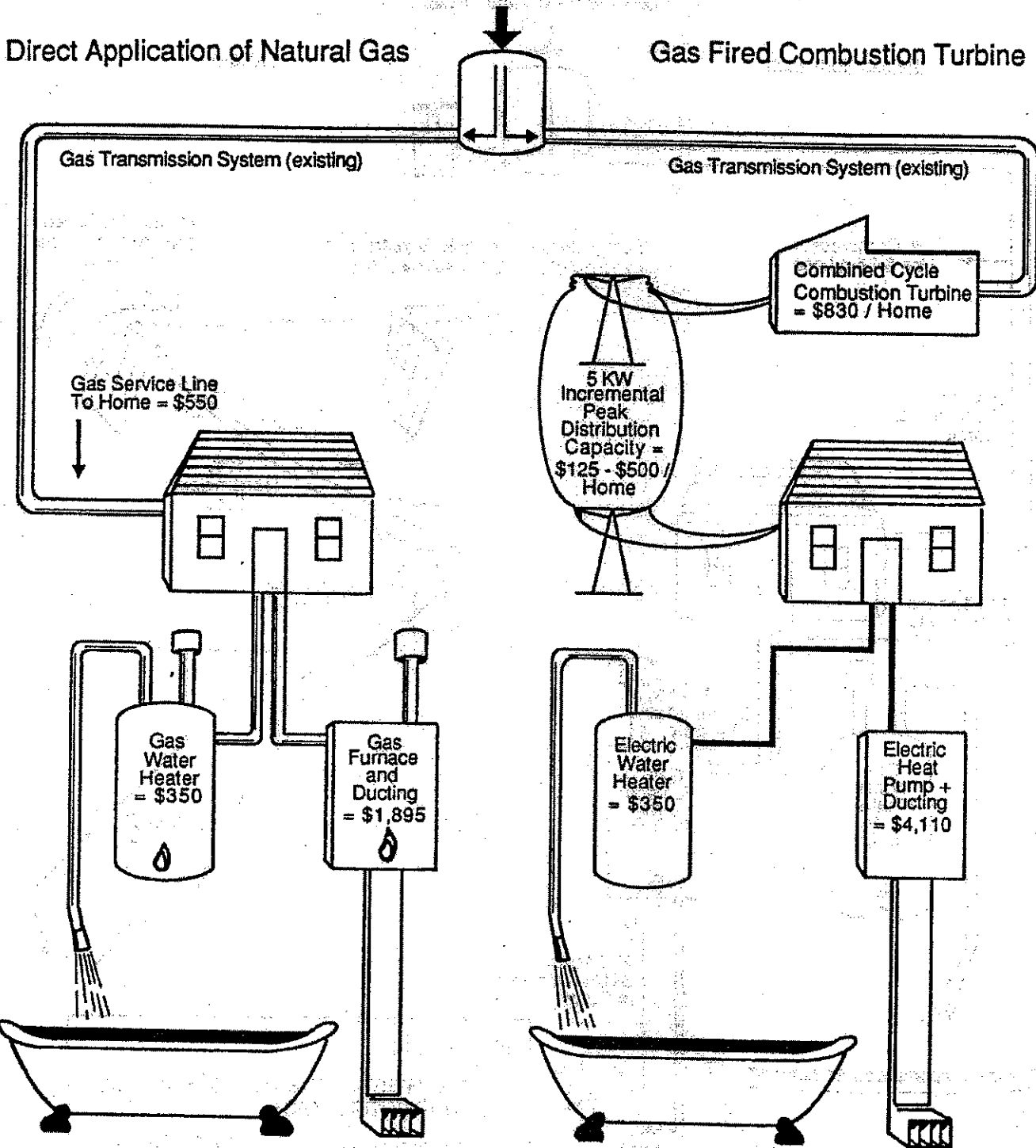


Figure 4

CAPITAL COST COMPARISON
 Gas-Fired Combustion Turbines vs. Direct Application of Gas



Gas Furnace + Ducting	=	\$1,895
Gas Water Heater	=	350
Gas Service Line	=	550
TOTAL		\$2,795

Heat Pump + Ducting	=	\$4,110
Water Heater	=	350
Incremental Peak Distribution Capacity	=	125 - 500
Combustion Turbines	=	830
TOTAL		\$5,415 - 5,790

**APPENDIX A
EXISTING NORTHWEST OIL/GAS GENERATING PLANTS**

	Plant Type	Fuel Type	Capacity (MW)
City of Bonners Ferry			
Bonners Ferry 1-3	D	Oil	7
Idaho Power			
Wood River	CT	Gas	50
Montana Power			
Bird	Steam	Gas/Oil	69
Pacific Power and Light			
Libby	CT	Oil	24
Portland General Electric			
Beaver	CCCT	Gas/Oil	545
Bethel	CT	Gas/Oil	114
Summit	D	Oil	6
Puget Sound Power and Light			
Crystal Mountain	D	Oil	3
Fredrickson	CT	Gas/Oil	169
Fredonia	CT	Gas/Oil	247
Shuffleton	Steam	#6 Oil	86
Whidbey	CT	Oil	28
Whitehorn 1	CT	Oil	68
Whitehorn 2/3	CT	Gas/Oil	178
Washington Water Power			
Northeast	CT	Gas/Oil	61
TOTAL OIL/GAS CAPACITY			1655

CT = Single Cycle Combustion Turbine; CCCT = Combined Cycle Combustion Turbine;
 Steam = Steam Boiler; D = Diesel
 Sources: PNUCC Thermal Resources Data Base, 1984; Puget Sound Power and Light
 Company FERC Form 1, 1987.

**APPENDIX B
THERMODYNAMIC EFFICIENCY AND CARBON DIOXIDE EMISSIONS**

Base Case: Direct Gas Space/Water Heat in Northwest

Northwest Usage	60.0 MMBTU 3/3 Years
California Usage	0.0 MMBTU 2/3 Years
Total CO₂ Emissions	7,080 Lbs/Year

Hydrofiring Base Case: California Uses Combined Cycle Gas @ 40%

Northwest Usage	83.1 MMBTU 1/3 Years
California Usage	67.3 MMBTU 2/3 Years
Average Usage	72.6 MMBTU
Total CO₂ Emissions	8,563 Lbs/Year

Hydrofiring Alternative 1: California Uses Gas @ 30% Efficiency

Northwest Usage	83.1 MMBTU 1/3 Years
California Usage	89.7 MMBTU 2/3 Years
Average Usage	87.5 MMBTU
Total CO₂ Emissions	10,325 Lbs/Year

Hydrofiring Alternative 2: California Uses Utah Coal @ 35% Efficiency; 10% Line Loss

Northwest Usage	83.1 MMBTU 1/3 Years
California Coal Usage	85.5 MMBTU 2/3 Years
Average Usage	84.7 MMBTU
Total CO₂ Emissions	14,948 Lbs/Year

Hydrofiring Alternative 3: California Uses Gas Cogeneration @ 60% Efficiency for Half of Generation; Combined Cycle @ 40% for Other Half

Northwest Usage	83.1 MMBTU 1/3 Years
California Usage	56.1 MMBTU 2/3 Years
Average Usage	65.1 MMBTU
Total CO₂ Emissions	7,682 Lbs/Year