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EVALUATION OF ELECTRICAL POWER ALTERNATIVES FOR THE PACIFIC NORTHWEST

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FOREWORD

This study was conducted for ERDA by TRW Energy Systems Planning Division, McLean, Virginia, as a task under Contract No. (49-1)-3885, "Planning and Analysis Support to ERDA/APAE." The objective was to evaluate the concept of implementation of large scale energy conservation to reduce end-use demand for electrical energy as an alternative to the need for continued construction of new power plants to meet projected energy requirements for the Pacific Northwest. In particular, the numerical accuracy, economic feasibility, and institutional impact of a conservation oriented scenario developed by the Natural Resources Defense Council, Inc., was assessed, relative to the energy forecast prepared by the Pacific Northwest Utilities Conference Commission. The results of this study are presented herein in five parts:

- Section 1.0 - Introduction and Summary
- Section 2.0 - Reconstruction and Numerical Evaluation of Alternative Scenario
- Section 3.0 - Economic Analysis
- Section 4.0 - Institutional Impact
- Section 5.0 - Impact of New National Energy Policy

The study was undertaken at the direction of R. W. LeGassie, ERDA Assistant Administrator for Planning, Analysis, and Evaluation. The ERDA study monitor was P. F. Castellon, Assistant Director for National and Field Plans, Office of Planning. The following TRW personnel participated part-time or full-time in the conduct of the study and contributed to the preparation of this report:

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TRW was supported by CONSAD Research Corporation, who contributed the institutional impact analysis. The CONSAD work was performed by Messrs. Gregg Ferris, Tom Osman, and David Habert under the direction of Charles Laidlaw.

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ABBREVIATIONS AND ACRONYMS

AAR	Average Annual Rate
APAE	ERDA Assistant Administrator for Planning, Analysis, and Evaluation
AS	Alternative Scenario
BLS	Bureau of Labor Statistics
BPA	Bonneville Power Administration
Btu	British Thermal Unit
C.F.	Capacity Factor
DOE	Refers to Oregon Department of Energy
EIS	Environmental Impact Statement
ERDA	Energy Research and Development Administration
FCR	Fixed Charge Rate
F.O.B.	Freight On Board
FPC	Federal Power Commission
HTPP	Hydro-Thermal Power Program
HVAC	Heating, Ventilation and Air-Conditioning
IRE	Interruptible Replacement Energy
kW	Kilowatts
kWh	Kilowatt-hour
kWh_e	Kilowatt-hour electrical
Mcf	Thousand Cubic Feet
MFD	Multifamily Dwelling
MIUS	Modular Integrated Utility System
MMBtu	Million British Thermal Units
MW	Megawatts
NEP	National Energy Plan
NERA	National Economic Research Associates, Inc.
NRDC	Natural Resources Defense Council
O&M	Operation and Maintenance
OBERS	Office of Business Economics and Economic Research Service
OPEC	Organization of Petroleum Exporting Countries
ORNL	Oak Ridge National Laboratory
PNUCC	Pacific Northwest Utilities Conference Commission
PNW	Pacific Northwest
PPL	Pacific Power and Light
PPS	Power Plant Scenario
R&D	Research and Development
R&M	Replacement and Maintenance
SFR	Single-Family Residence
SMSA	Standard Metropolitan Statistical Areas
SOM	Skidmore, Owings and Merrill

ABBREVIATIONS AND ACRONYMS (Continued)

T&D	Transmission and Distribution
TEE	Total Effective Electrical Energy
TES	Total Energy System
TPC	Thermal Performance Coefficient
WIOM	Washington State Input-Output Model

1.0 INTRODUCTION AND SUMMARY

1.1 INTRODUCTION

Intermediate to long-range projections of energy consumption in the United States made in the last five years, particularly those based on extrapolation from historical trends, have generally predicted an ever increasing level of demand. For example the "No New Initiatives" scenario in ERDA-48 (Reference 1), predicts a total energy consumption increase from 72 quads in 1975 to 164 quads in the year 2000, and predicts increases in electrical energy generation from approximately 7 quads to approximately 23 quads. National concerns regarding the availability of sufficient energy to meet such forecasted demands, exacerbated by the OPEC oil embargo of 1973 and the threat of future embargoes and the more recent natural gas shortage of the winter of 1976-1977, have led to focused attention on the need to reduce this increasing demand through conservation and increased efficiency in end-uses of energy.

The impacts arising from particular conservation and/or energy substitution initiatives can be expected to vary widely between geographical regions of the United States. This is a consequence of regional differences in the current relative proportions of usage of various energy resources (e.g., domestic oil, imported oil, domestic gas, imported gas, hydroelectric power, coal and nuclear fuels) and the differing regional potentials for increased utilization of one or more of these resources or a significant shift to new energy sources (e.g., solar, winds, geothermal). Thus, detailed implementation analyses must be conducted on a regional level, to be sensitive to the regional peculiarities of energy use.

The ERDA Office of Planning, Analysis and Evaluation (ERDA/APAE) is concerned with such analyses, particularly from the point-of-view of determining priorities for ERDA R&D funds among new technologies. Analyses have previously been conducted to estimate future electrical energy demand and therefrom requirements for new electrical generating capacity for the Pacific Northwest region. The Alternative Scenario analysis conducted by the

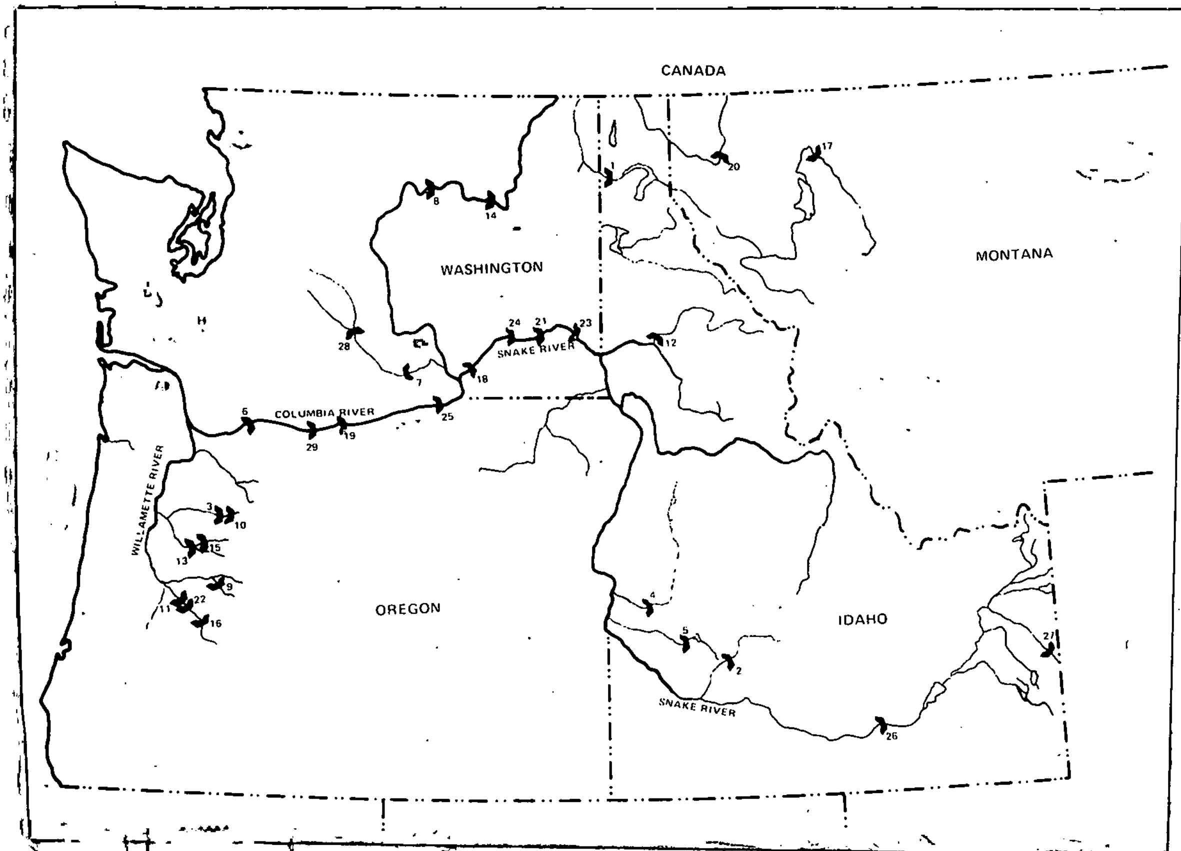
Natural Resources Defense Council, partly funded by ERDA/APAE, develops a conservation-oriented alternative to massive construction of new generating capacity to satisfy projected demand increases. TRW was tasked by ERDA/APAE to review the Alternative Scenario[1] in detail, primarily to assess the underlying concept.

1.2 BACKGROUND

The Pacific Northwest area possesses more than 40% of the nation's hydroelectric potential, and has the most highly developed hydroelectric system in the world. Approximately 84% of the region's electric generating capacity is provided by a combination of 160 Federal, other public and investor-owned hydroelectric projects. Roughly 7% of the region's capacity is nuclear generated, 5% is coal based, and 4% is oil based (Reference 45). The power system is linked to California by three reversible interties which, during periods of high water, can wheel surplus power to California. The system of dams, located on the Columbia, Snake, and Willamett Rivers and their tributaries, also has irrigation, flood control, navigation, water supply, and recreation functions.

Over 50% of the electricity consumed in the Pacific Northwest is furnished by 29 Federal dams built, operated and maintained by the Bureau of Reclamation and the Corps of Engineers (Figure 1.2-1). The power generated by these dams is marketed and transmitted throughout the region by the Bonneville Power Administration (BPA). Additionally, BPA currently markets power acquired from two thermal plants, Hanford and Trojan (Reference 2). In the Pacific Northwest, the BPA transmission network represents approximately 80% of the bulk power transmission system. Power is sold to publicly-owned utilities (municipalities, public utility districts, and cooperatives), federal agencies, and privately-owned utilities. Additionally, power is sold directly to 22 industrial plants including producers of aluminum, carbides, ferro-alloys, wood products and various chemicals, and when available, surplus power is exported outside the region. In FY 1976, BPA sold 77,471 million kWh's at an average rate of 3.7 mills/kWh to its customers (Reference 2). This low rate, due to the preponderance of hydroelectric power, contrasts sharply with much higher rates in other regions of the country where power is provided primarily by thermal generation.

[1]As defined in the January 31, 1977, NRDC report, Choosing An Electrical Energy Future for the Pacific Northwest: An Alternate Scenario, (Reference 3).



FEDERAL COLUMBIA RIVER POWER SYSTEM

GENERAL SPECIFICATIONS AND PEAKING[1] CAPABILITY OF EXISTING INSTALLATIONS AS OF 6/30/76

PROJECT	OPERATING AGENCY	LOCATION[2]	INITIAL DATE IN SERVICE	TOTAL CAPABILITY PW	AUTHORIZED[3] PURPOSES
1 Albeni Falls	CE	I	3/55	49.00	P,R,N,FC,S
2 Anderson Ranch	BR	I	12/50	34.50	P,I,FC,S
3 Big Cliff	CE	O	6/54	20.70	P,FC
4 Black Canyon	BR	I	12/25	10.20	P, I, FC
5 Boise Diversion	BR	I	5/12	2/25	P, I
6 Bonneville	CE	O-W	6/38	574.00	P,N,R
7 Chandler	BR	W	2/56	13.00	P,P,I
8 Chief Joseph	CE	W	8/55	1,280.00	P, R
9 Cougar	CE	O	2/64	28.75	P,FC,R,N,S
10 Detroit	CE	O	7/53	115.00	S,P,I,FC,R,N,W
11 Dexter	CE	O	5/55	17.25	P, FC
12 Dworshak	CE	I	9/74	460.00	P,N,FC,R,S
13 Foster	CE	O	8/68	23.00	P,I,FC
14 Grand Coulee	BR	W	9/41	3,492.40	P,I,FC,N,S
Gr. Coulee (Pump. Gen.)		W	12/74	115.00	
15 Green Peter	CE	O	6/67	92.00	P,I,FC,R,N,S
16 Hills Creek	CE	O	5/62	34.50	W,P,I,FC,R,N,S
17 Hungry Horse	BR	M	10/52	328.00	P,FC,N,S,I
18 Ice Harbor	CE	W	12/61	693.30	P, N, R
19 John Day	CE	O-W	7/68	2,484.00	P,N,FC,R,I,S
20 Libby	CE	M	8/75	483.00	P,FC,S,R,N
21 Little Goose	CE	W	5/70	465.75	P, N, R
22 Lookout Point	CE	O	12/54	138.00	W,I,P,FC,R,N,S
23 Lower Granite	CE	W	4/75	465.75	P, N, R, I
24 Lower Monumental	CE	W	5/69	465.75	P, N, R, I
25 McNary	CE	O-W	11/53	1,127.00	P, N, R
26 Minidoka	BR	I	5/09	16.00	P, I, S
27 Palisades	BR	I	2/57	135.00	P,I,FC,S,W
28 Roza	BR	W	8/58	12.90	P, I
29 The Dalles	CE	O-W	5/57	2,015.00	P, N, R

[1] Maximum peaking capability @ normal full pool elevation and full gate tailwater. Unit peaking capability varies from 100% to 116% of nameplate rating.

[2] I = Idaho; M = Montana; O = Oregon; W = Washington.

[3] P = Power; I = Irrigation; N = Navigation; FC = Flood Control; R = Recreation; S = Power Storage; W = Water Supply.

FIGURE 1.2-1. PACIFIC NORTHWEST REGION

In the last decade BPA and 108 area utilities cooperated in the establishment of the Northwest Hydro-Thermal Power Program (HTPP) to meet forecasted demands for electric power needs beyond those which could be satisfied with hydro power. Phase 1 of this program has been completed. Phase 2, the implementation plan through 1986, has apparently been terminated.

On April 18, 1975, a lawsuit was filed against BPA (specifically the Port of Astoria, et al vs. Hodel, et al) challenging BPA's intent to provide power to the Alumax Pacific Corporation's proposed aluminum plant in the Demiston-Umatilla area of eastern Oregon (Reference 46). The Court determined that BPA must prepare an Environmental Impact Statement (EIS) of the proposed Alumax service and on BPA's role in general in supplying power in the Pacific Northwest. Consequently, BPA has undertaken the preparation of a "role" EIS, the completion of which will take over two years and will cost about $4 million (Reference 2). Additionally, BPA has stipulated that no new electrical service contracts with industrial customers will be signed prior to completion of the EIS.

To ensure public participation in the role EIS preparation, BPA solicited "affirmative" contributions from environmental groups including the Natural Resources Defense Council (NRDC). In response, NRDC constructed the Alternative Scenario defined in Reference 3. This scenario contrasts sharply with the energy demand forecast prepared by the Pacific Northwest Utilities Conference Commission and the proposed schedule of new plant construction to meet the forecasted demand. As stated in Reference 3, the "central station scenario" considered by BPA and area utilities forecasts a 20-year increase in electricity demand of 150%. It assumes that approximately 26 new coal-based or nuclear large-scale power plants would be constructed to meet future base load requirements, and that the Columbia River Power System dams would be used increasingly to provide peaking capacity. Due to the large capital requirements associated with construction of these power plants and related transmission facilities, it has been recommended that the Federal Government provide indirect financing through advance, long-term commitments to purchase power. On the other hand, the Alternative Scenario recommends large-scale implementation of conservation to reduce future electricity demand and, consequently, the need for new power plants. The projected energy requirements in the Alternative Scenario were determined on the basis of end-use analyses of the residential, commercial, manufacturing, and agricultural sectors of the Pacific Northwest. The scenario concludes that no new power plants are built in the next 20 years, beyond those already approved or under construction, and even under these conditions projects a power surplus of over 4000 average megawatts for the region in 1995. Although the scope of the Alternative Scenario analysis is constrained to the next 20 years, its objective is to provide for a transition from continued high growth in electrical consumption and reliance on large central power stations to increased usage of smaller scale renewable energy systems and substantially reduced growth in total supply. According to the scenario, this transition would provide for a more stable situation in the decades beyond 1995.

Due to the historical availability of substantial quantities of low-cost hydroelectric power, a concentration of energy intensive industrial plants has developed in the Pacific Northwest. In particular, the regional primary aluminum industry, consisting of reduction and rolling plants owned by six major aluminum companies, comprises approximately 30% of the nation's aluminum production capacity, and, in FY 1976 purchased approximately 29% of the electricity marketed by BPA (Reference 2). The direct-service power contracts with BPA for these plants expire in the mid-1980's.[1] A recommendation of the Alternative Scenario is that only those aluminum plants that are less than 35 years of age when their current contract expires should have their power contract renewed by BPA. By this criterion eight of ten plants would not have their contracts renewed, and would likely be retired. Options available to the aluminum plants and resulting potential impacts on the region and the nation under these circumstances are considered later in this report. It should be stressed that the Alternative Scenario projects a surplus of slightly over 4000 average megawatts in 1995 which would be sufficient to continue service to the aluminum industry without any of the plants being phased out. However, if additional power plants are not built, the surplus becomes available only if the conservation initiatives are fully implemented at the rates assumed and result in the projected energy savings.

[1]BPA has formally notified its preference customers (customers to whom BPA by law must give preferential service) that insufficient power will be available to meet their projected load growth after 1983. Issuance of the insufficiency notices has naturally caused serious concern among the customers. They and prospective new preference customers have indicated they will lay claim to the electrical power which could become available following the expiration of industrial contracts in the mid-1980's (Reference 2).

1.3 TRW STUDY OBJECTIVE, SCOPE, AND IMPLEMENTATION

As previously indicated, TRW was tasked by ERDA to review the Alternative Scenario primarily as a prototype analysis of the concept of implementation of massive conservation to reduce demand for electricity versus construction of sufficient power plants to satisfy unconstrained demand. This study consists of four parts:

- An assessment of the numerical accuracy of the Alternative Scenario
- An economic comparison of the two scenarios
- A study of the institutional barriers which might inhibit or slow implementation of the initiatives postulated in the Alternative Scenario and
- An assessment of the relative impact on the two scenarios of the President's National Energy Policy.

This study thus specifically avoids creation of a new scenario, but examines in detail these scenarios which are considered alternate courses of action for the future.

Various other considerations, although not included in the scope of this study, are relevant to the individuals faced in the very near term with decisions regarding the course of action to be followed in determining and meeting the region's future electrical needs (e.g., decisions regarding construction of the Skagit and Pebble Springs nuclear power plants). These considerations include potential environmental consequences related to the Power Plant Scenario and the risk of shortfalls evaluated independently for both scenarios.

Generally conservative assumptions (e.g., costs of improved-efficiency appliances, financing of home improvements at a 7% real interest rate for five years) were employed in estimating costs of implementation of the Alternative Scenario. Additionally, by truncating the analysis at 1995, accrual of benefits beyond 1995 from some improvements paid for in the 20-year period is not considered.

1.4 SUMMARY OF PRINCIPAL FINDINGS AND CONCLUSIONS

The following general conclusions were drawn from this study. Detailed discussions and supporting data relating to each conclusion are presented in appropriate sections of the text of this report.

- The Alternative Scenario electrical demand forecasts to the year 1995 for the PNW region are significantly lower than those made by the PNUCC. This variation does not arise entirely from implementation of the Alternative Scenario recommendations. A baseline projection implicitly derived from the Alternative Scenario methodology by assuming none of the scenario recommendations are followed accounts for approximately one-half of the variation.

- The Alternative Scenario does not consist solely of the implementation of a set of technical energy conservation measures which result in a lower electrical energy demand. Measures are included which involve service modifications, in particular:

  --lowering room air temperature (thermostat setting)

  --reducing water heating temperatures

  --reducing lighting levels in commercial buildings

  --possibly lower incomes for individuals currently employed in the aluminum industry due to acceptance of jobs in other industries, as prescribed by the employment mix changes in the manufacturing sector, which pay lower average weekly wages.

- Numerical results of the Alternative Scenario analysis were verified and found to be consistent with the scenario assumptions except for a few minor errors in the commercial sector. The errors do not affect the conclusions.

- There appears to be a significant overestimation in the Power Plant Scenario of electrical energy requirements for the manufacturing sector both in 1985 and 1995. Specifically in the subsector categorized as "other industrial," BPA projects more than a 10-fold increase in demand between 1974 and 1995, making this category the single largest consumer of electricity in the sector in 1995. The magnitude of this overestimation may be more than twice the 1975 usage of the primary aluminum industry, currently the largest industrial electrical energy user in the region.

- The price of electricity to PNW consumers would be considerably higher if the Power Plant Scenario is followed than if the Alternative Scenario were successfully implemented. From identical electricity prices in 1976, prices in the Alternative Scenario would be 15% less in 1985 and 30% less in 1995 than in the Power Plant Scenario. This results from the need for much more high-cost thermal generation in the Power Plant Scenario relative to the Alternative Scenario, and consequently higher blended electricity prices.

- Total annual costs over 20 years to the consumers in the residential and commercial sectors would be slightly less for the Power Plant Scenario for the first five years. Thereafter the Alternative Scenario shows an increasing advantage to 1995. The present value of the difference in costs measured over the 20-year period was $6.3 billion in favor of the Alternative Scenario.

- Employment mix changes included in the Alternative Scenario to compensate for direct unemployment caused by recommended aluminum plant shutdowns will be difficult to achieve. Even if possible, shutdown of a major portion of the regional aluminum industry would lead to serious localized impacts and a net regional loss of employment due to induced effects.

- Levels of implementation of passive conservation measures proposed in the President's National Energy Plan (NEP) for 1985 exceed those in the Alternative Scenario.

1.4.1 <u>Specific Findings from Section 2.0</u>

- A significant difference between the two scenarios occurs in the appliance category of the residential sector. The Power Plant Scenario projects a two-fold increase in demand over the next 20 years without explanation or justification, whereas the Alternative Scenario projects a much more modest increase.

- In the combined residential and commercial sectors, nearly a third of the demand difference between the scenarios projected for 1995 is due to the lower baseline projection that is implicit in the Alternative Scenario.

- In the manufacturing sector, the Alternative Scenario postulates employment mix changes to achieve an overall less energy intensive industrial base, without verification of viability and social impact of these changes. Additionally, across-the-board energy efficiency improvements were assumed without specific analysis. However, these changes (including the assumed electrical energy substitutions) account for less than half the difference in the two scenarios in 1995 for this sector. The balance is due to the lower baseline projection of the Alternative Scenario (note the Power Plant Scenario apparently sharply overestimates demand in the "other industrial" category). In particular, the energy efficiency improvements only account for approximately one-eighth of the total 1995 difference in the two scenarios for this sector.

1.4.2 <u>Specific Findings from Section 3.0</u>

- A 20-year cost comparison of the two scenarios was conducted for the combined residential and commercial sectors. It was not possible to compute implementation costs for the manufacturing sector due to the non-specificity of the efficiency improvements postulated by the Alternative Scenario. The inherently lower energy demand in the Alternative Scenario and the lower average blended price of electricity as a consequence of the much smaller inventory of high priced new thermal generation result in making the implementation of conservation measures a cost-effective approach. This conclusion is reinforced by the generally conservative assumptions employed in costing implementation of the Alternative Scenario.

- In all categories of residential dwellings and commercial buildings, the passive conservation measures (insulation, weatherstripping, storm windows, etc.) provided at least 85% of the savings obtained from conservation. In many cases the active measures were not cost effective over the 20-year period from the consumer's point-of-view (total energy cost savings resulting from implementation over the 20 years did not exceed total costs). In particular neither solar space heating nor water heating proved to be cost effective in either residential dwellings or commercial buildings; the total energy system (assumed in this study to be natural gas fuel cell systems) was cost effective in commercial buildings but not in residential dwellings (partly because it was sized to meet peak requirements); and heat pumps were not cost effective in existing residential dwellings (as a retrofit) or in new multifamily dwellings but were cost effective in new single-family residential dwellings. Note that these findings are specific to the Pacific Northwest region.

- The average unit cost of conservation is much higher in the residential sector than the commercial sector. This is due to the higher use of the less cost-effective active measures in the residential sector plus the assumed high turnover rate of appliances over the 20 years.

- From a capital investment point-of-view, the expenditure for conservation in the residential sector is higher than the corresponding cost for supplying electricity if the conservation measures were not implemented. In the commercial sector, the cost of conservation is significantly lower than the cost of equivalent supply. However, the cost of conservation in the combined sectors is lower than the cost of equivalent electricity supply.

1.4.3 Specific Findings from Section 4.0

- There are numerous institutional barriers to implementation of the Alternative Scenario conservation initiatives at the rates specified. Consequently, the surplus in generating capacity projected in the scenario by 1995 may be required as a contingency.

* The use of projected surplus power as a contingency would require the Alternative Scenario recommendation for significant phasedown of the region's primary aluminum industry to be implemented. Such a phasedown would, however, have a severe impact on local and regional economies. Even if the direct employment loss could be fully offset by the postulated gains in regional direct employment in other subsectors, there would still be local disruptions, particularly in counties where an aluminum plant is the major employer. Additionally there would be a net regional loss in induced service jobs outside the regional manufacturing sector, partly because the high wages paid by the aluminum industry would not be matched by other industries. Due to the high assessed value of the aluminum plants and the industry's high value of output per employee, there would be net losses in local property taxes, state sales and income taxes (for certain states), as well as federal income taxes. To avoid reductions in public services provided in the region, these losses would have to be offset by increases in other taxes.

* The manufacturing subsectors postulated to have the greatest direct employment increases (relative to BPA projections) by the Alternative Scenario (mainly to offset direct losses assumed for the primary aluminum industry) were individually analyzed. In all cases, the postulated increases appear questionable. In particular, associated productivity increases that require capturing a share of national markets would be difficult to achieve due to the PNW's spatial isolation disadvantage. In general, employment growth is a function of demand, which in turn is a function of income, consumer preferences, etc. The ability to arbitrarily distribute employment implies an ability to manipulate these factors, which would require a planning and political capacity which, up to the present time, is either administratively unobtainable and/or politically unacceptable.

1.4.4 Specific Findings from Section 5.0

* A comparison of implementation rates for conservation between the National Energy Plan (for those measures where rates are specified) and the Alternative Scenario shows that in general the implementation levels are higher for the NEP.[1] This comparison lends credence to the levels assumed for the Alternative Scenario.

* Implementation of the NEP would have only a slight effect on the 20-year cost comparison. The Alternative Scenario disadvantage for the first few years would be lessened due to the incentives, and the Power Plant disadvantage thereafter would be slightly lessened due to implementation of some amount of conservation in that scenario (this comparison was made using the assumption that no changes were made in the power plant schedule for new power generation, and thus the blended price of electricity was unaffected).

[1] As this report was going to press, there were reports the NEP implementation levels were being reduced. The new levels would be more comparable to, but still usually greater than, those in the Alternative Scenario.

2.0 RECONSTRUCTION AND NUMERICAL EVALUATION OF ALTERNATIVE SCENARIO

2.1 INTRODUCTION

The Pacific Northwest Utilities Conference Commission (PNUCC) prepares long-range projections of power loads and resources for the West Group Area of the Northwest Power Pool. The West Group Area includes the states of Washington, Oregon and Idaho and the western part of Montana, but does not include the service areas of Idaho Power Company, Utah Power & Light and California Pacific Utilities Company. The West Group Area is representative of the major part of the Pacific Northwest region, having 96% of the region's population, but is normally not considered synonymous with the Pacific Northwest. The Alternative Scenario uses the West Group Area as the reference area, though for convenience often refers to it as the Pacific Northwest.

The PNUCC 20-year load forecast and schedule of implementation of new capacity to meet the forecasted demand (Reference 11) defines a baseline scenario, hereafter referred to in this report as the "Power Plant Scenario," against which the Alternative Scenario defined in Reference 3 is contrasted. For the base years 1975, 1985, and 1995 considered in the Alternative Scenario, BPA computed breakdowns of the electricity demand by sector. The PNUCC forecast and these sector breakdowns are shown in Figure 2.1-1. The Alternative Scenario report forecasts a substantially lower future demand for electricity, based on a different forecasting methodology and reduction in demand resulting from implementation of conservation. This lower forecast is contrasted against the PNUCC forecast in Figure 2.1-2. The total difference in forecasts is also disaggregated in Figure 2.1-2 according to the four end-use sectors considered in the Alternative Scenario (residential, commercial, manufacturing, agriculture). It may be observed that the agriculture sector accounts for very little of the difference between forecasts. Consequently, the evaluation conducted herein focuses only on the residential, commercial, and manufacturing sectors.

The computations which result in the projected Alternative Scenario demands were reconstructed from the data and procedures specified in Reference 3. It is the purpose of this section to: (1) describe in detail the manner in which the Alternative Scenario was reconstructed, (2) point out the problems

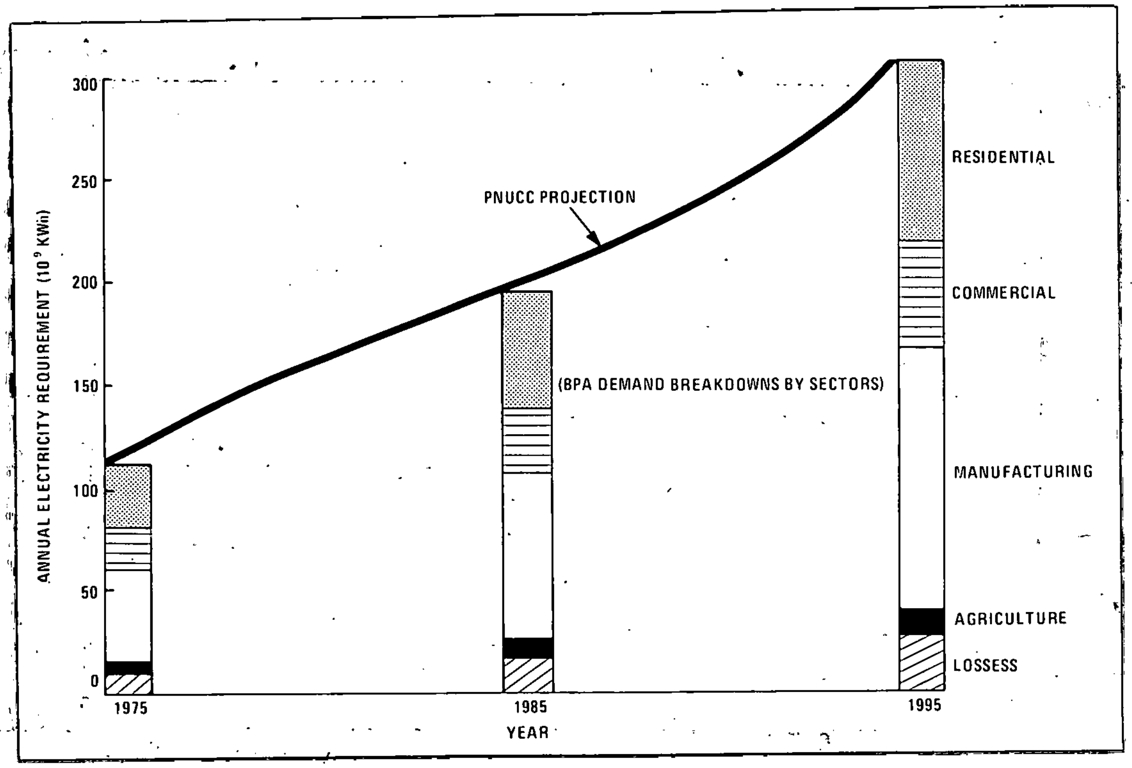


FIGURE 2.1-1. POWER PLANT SCENARIO FORECAST OF PACIFIC NORTHWEST ELECTRICITY REQUIREMENT

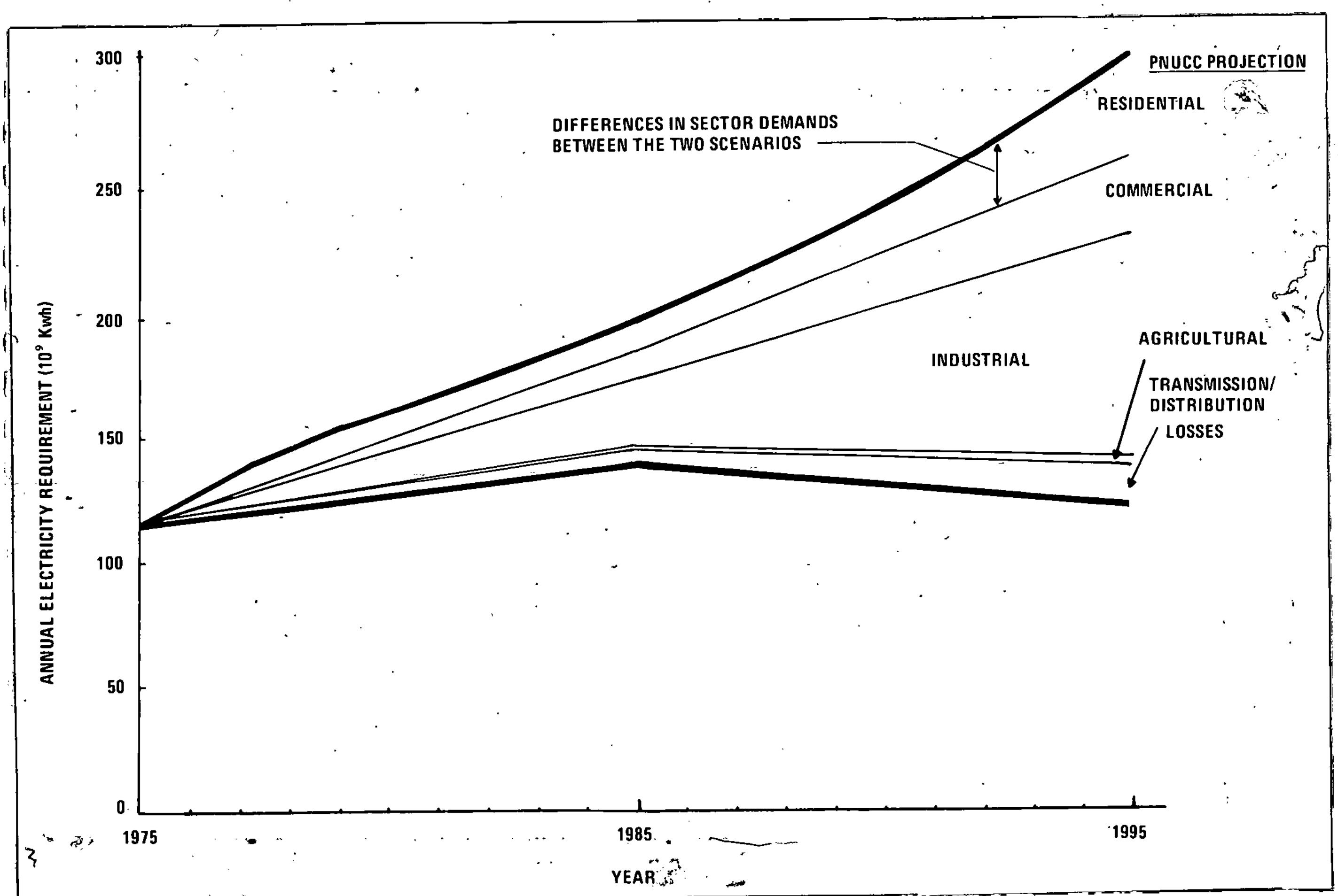


FIGURE 2.1-2. DIFFERENCES IN PNUCC & ALTERNATIVE SCENARIO PROJECTIONS OF ELECTRICAL ENERGY REQUIREMENTS TO 1995

discovered in the course of doing it, and (3) suggest ways to rectify the problems if possible, and if not, to assess their impact on the viability of their proposed scenario.

The residential sector is addressed first, in Section 2.3, followed by the commercial sector (Section 2.4), and the manufacturing sector (Section 2.5).

2.2 THE RESIDENTIAL SECTOR: DESCRIPTION AND ANALYSIS

Electric connections to residential units make up about 85% of all electric company customers and the sector demand in 1975 was 33% of all electricity sales within the PNW region. The residential sector's use of electricity is difficult to forecast because of the many complex factors involved. Population changes, dwelling unit changes, family formation, working and shopping habits and time schedules, appliance saturations and use patterns, fuel choices and relative prices are examples.

The Alternative Scenario Report places much stress upon the analytical methodology which it follows for the PNW Region, a detailed end-use analysis of the demand and need for electricity. This methodology in the residential sector builds upon the methods used in the Skidmore, Owings and Merrill (SOM) report to BPA (Reference 4). It is contrasted by NRDC to two other general methodologies: the historical-trends projection methods followed generally by BPA and the PNW utility companies; and the econometric modeling method, of which studies conducted for the PNUCC by the National Economic Research Associates (NERA) are an example.

2.2.1 The Alternative Scenario Residential Sector--Description

The Alternative Scenario considers the residential sector electricity demand relative to two major end-use demand categories. The first demand category is space heating, which accounted for 34% of 1975 residential electricity use in the region. The second category is a combination of electric water heating (26%), lighting (10%) and electric appliances (30%), which were treated in somewhat less detail, being independent of the type of residential housing unit where they were used. This two-part treatment parallels the procedure used in the SOM Study but extends the analysis in certain ways. Following the SOM procedure the Alternative Scenario distinguishes four prototypical dwelling types, single-family units existing and new and multifamily units existing and new.

Figure 2.2-1 shows the potential electrical energy demand for the residential sector which the Alternative Scenario identifies relative to BPA projections. It is important to note that BPA projected end-use demands

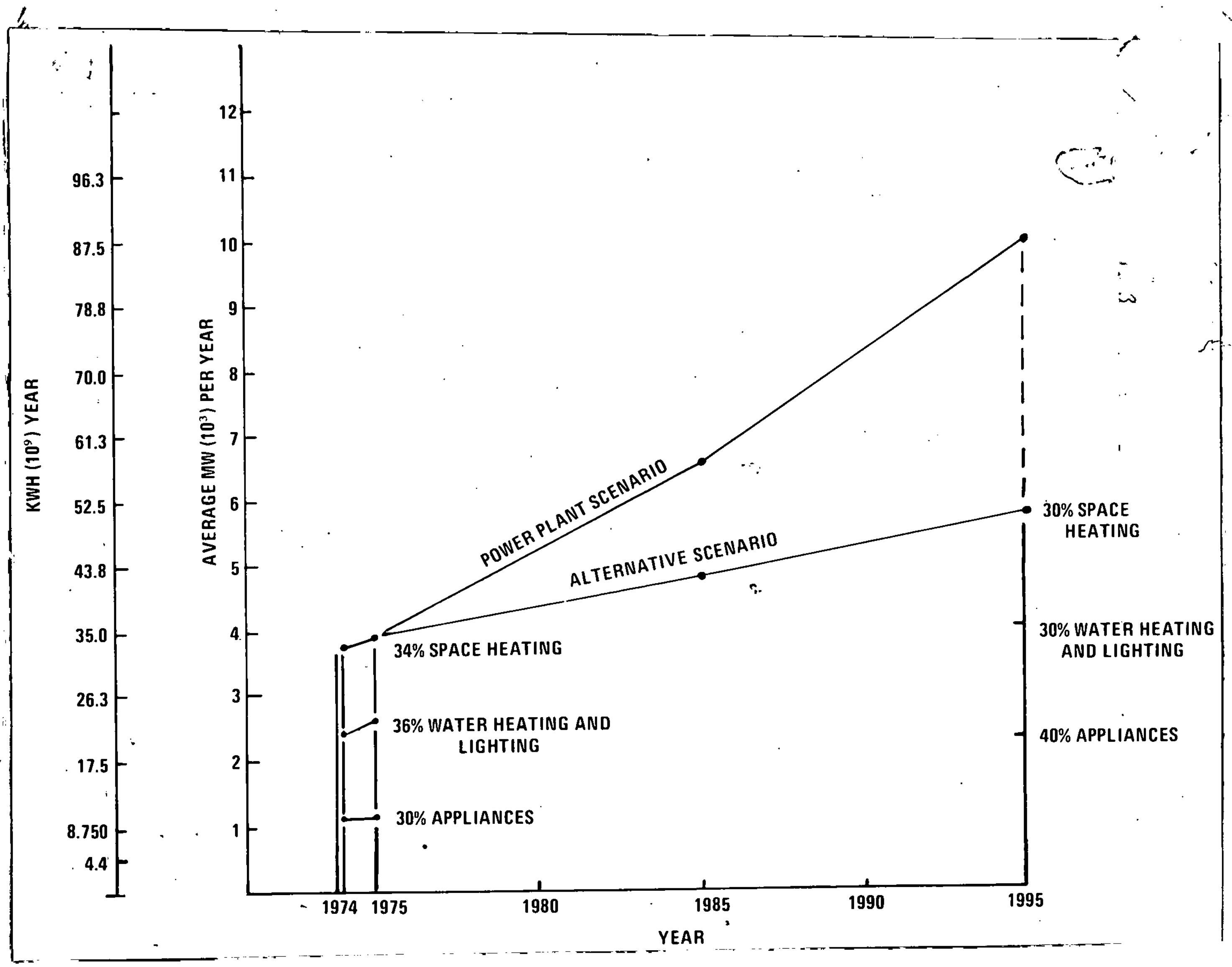


FIGURE 2.2-1. ELECTRICAL ENERGY REQUIREMENTS FOR THE RESIDENTIAL SECTOR IN THE TWO SCENARIOS

for 1980 and 1995 from a 1974 base year, whereas the Alternative Scenario revised the baseline to 1975 and projected 1985 and 1995 demands. The figure shows both annual kilowatt-hours of generation and annual average megawatts required through 1995. The detailed end-use analysis was conducted in terms of kWh/year demand, while final results were reflected in terms of annual average and peak megawatts (MW) to permit technical judgments to be made on central station generating capacity requirements in the scenario--the central focus of conclusions reached by the Alternative Scenario Study.

The figure shows that if the Alternative Scenario were implemented and resulted in the calculated consumption levels, demand would be reduced by 26% of the BPA projected demand in 1985 and 47% in 1995. It also shows the starting and final proportions of major end-use demands--for space heating, for water-heating and lighting, for all appliances--projected in the Alternative Scenario. These proportions of total residential demand shift heavily over two decades towards satisfying the needs of home electrical appliances, from 30% in 1975 to 40% in 1995 of total residential use, almost similar to the BPA projections.

2.2.1.1 Alternative Scenario Methodology

The sequential operations performed in the analysis of the electricity demands for space heating in the Alternative Scenario are shown in Table 2.2-1. Four prototypical buildings representative of four dwelling types were considered and the total number of buildings in each type projected to 1985 and 1995. Of these totals, the fraction that were electrically heated were singled out through projections of electric heat saturation levels in each type of residence both in 1985 and 1995. Linear rates of implementation of each passive energy conservation measure, i.e., insulation, storm windows, weatherstripping, were assumed in the scenario between 1975 and 1995 in each of the four dwelling types. The overall effect of the implementation of these measures was reflected in terms of an average thermal performance coefficient for each prototypical building that also declined at a linear rate starting from unity in 1975. The unity coefficient for each type of dwelling corresponded to an annual kWh requirement for space heating and

TABLE 2.2-1

RESIDENTIAL SECTOR COMPUTATIONAL PROCEDURE FOR ESTIMATING ELECTRICITY DEMAND (ALTERNATIVE SCENARIO)

SPACE HEATING: Type Home	Total Number of Homes	x	Saturation	x	Baseline Annual Energy Requirements Per Home[1]	x	Thermal Performance Coefficient	x	1-Fractional Decrease In Energy Use Due To Technology Substitutions[2]	=	Total
Single-Family, Pre 1976											-
Single-Family, Post 1975	Data given by type and year.		Data given by type and year.		kWh/yr by type.		Data given by type and year.		Data given by type and year.		-
Multiple-Family, Pre 1976											-
Multiple-Family, Post 1975											-
											Σ_1=total space heating requirement for 1975, 1985 or 1995

WATER HEATING, LIGHTING, OTHER APPLIANCES	Total Number of Homes	x	Electrical Appliance Saturation	x	Electrical Energy Use/Appliance	x	1-Fractional Decrease In Energy Use Due To Technology Substitutions[3]	=	Total
			Data given for 12 categories, for each year.		Data given by category and year.		Data given by type and year.		-
Total Sector Requirement = $\Sigma_1 + \Sigma_2$									Σ_2=total appliance energy requirement for 1975, 1985 or 1995

[1]At unity thermal performance coefficient for each type of dwelling.

[2]Use of heat pumps, solar space heating and total energy systems.

[3]Use of solar water heating.

these were specified for each of the four building prototypes in the scenario. Consequently, knowing the number of buildings in each type of dwelling that are electrically heated and the corresponding average annual kWh requirement per building, the sector's electrical energy demand for this end-use category is determined for the years 1985 and 1995.

The Alternative Scenario further assumes certain levels of implementation of active conservation measures comprising heat pumps, solar space heating and total energy systems in each of the four dwelling types in 1985 and 1995. These measures are assumed to be additive to the passive measures and their use for space heating conserves electricity relative to conventional resistance heating (either through improved efficiency as in the case of heat pumps or through substitution in the other two cases). Consequently, the overall sector electricity demands previously calculated for 1985 and 1995 are reduced in proportion to the level of implementation of these measures in these years and the fraction of average annual space heating demand saved by each, when considered over all four building types.

The total annual sector space heating electricity requirements in 1985 and 1995 estimated in kWh is readily translated into annual "average megawatt" requirements using 8760 hours per year and 1000 kW per MW. In order to assess the contribution to the system peak from residential space heating demand, the Alternative Scenario assumes a ratio at system peak of space heating electricity demand relative to the annual average. These ratios have historical precedents and are forecast by the utilities for future generation planning. The Alternative Scenario appears to have followed utility practice in forecasting these ratios for 1985 and 1995.

The methodology for calculating electricity requirements for electric water-heating, lighting, and major electric appliances is similar to that described for space heating, except that in this case no distinction need be made between electric and non-electric heated dwellings. All dwellings have electric appliances. Consequently, the four dwelling types are collapsed into a single, total number of homes for each given year. Annual electrical requirements are defined in 1985 and 1995 for water heaters, lights and all appliances; their respective saturation levels in these years are also forecast. A 60% decrease in electric water-heater requirements is specified for residences that use solar water heaters. The annual "average megawatts" demand is multiplied by a specified peak-to-average multiplier for water heaters, lights and each appliance, both in 1985 and 1995 in order to assess their individual contributions to system peak.

The sum of the electric energy demands of the two major categories in 1985 and 1995 represents the Alternative Scenario estimations of residential sector electricity needs in these years from the consumers' point of view. The impact on the electric utilities is the corresponding total "average megawatts," the total megawatt requirements at system peak and associated transmission and distribution losses.

Based on the procedure outlined above, the numerical results presented in the Alternative Scenario for this sector were validated.

2.2.2 Analysis of Alternative Scenario Methodology: Residential Sector

An evaluation of the methodologies used for end-use analysis of the electrical demand in the residential sector and the creation of an Alternative

Scenario must be made from various points of view. In particular it is important to analyze and evaluate the NRDC methodology upon its own terms, using its own assumptions. From this point of view, the Alternative Scenario must be judged a detailed, highly explicit, quantitative approach to the complex process of forecasting specific elements of residential demand over two decades. It is a convincing approach to the difficult job of forecasting sector needs for cases where behavioral and technical engineering processes are both involved and condition equally the acceptability of results and findings. Because it is so explicit, this approach lends itself well to verification in any future forecast year, or to recalculation of results if new technical or social factors and trends are detected.

The Alternative Scenario Report recognizes that its methods and results depend heavily upon the work done for the SOM Study. Consequently, there are many similarities in the residential sector analysis. The Alternative Scenario Report adopts Strategy Number 6 (Mandatory Conservation Program) from the SOM Study as its baseline for a "conservation scenario," relying upon results from a SOM computerized model which tested a variety of energy-saving measures for 1975-1995 implementation to derive specific improvements in annual electric energy demands in each of four "prototypical" dwellings of the region. These measures included homeowner behavior changes and conservation investments for both 1975 housing stock and subsequent construction.

The Alternative Scenario Analysis extends the SOM Study procedure, however, to explicitly weight the probable introduction of additional energy-saving devices; these are heat pumps, solar space heating systems, total energy systems and solar water heaters. The efficiency and saturation (percent introduction at a single time cross-section) are forecast for each of these technology items. This is a direct advantage of the engineering-type end-use analysis adopted in the Alternative Scenario. Conventional historical/judgmental trends analysis methods and statistical/econometric analysis methods cannot be adapted readily to this type of study of technical change and specific homeowner response. However, it is worth noting that only 2% of the reports' forecast of central-station electrical generation savings was due to the consideration of these new electricity-saving devices.

It is possible to argue whether faster introduction of these devices is probable. However, in the context of the scenario, an adoption of "penetration" rates even two or three times that considered, which would result in significant energy savings in this sector is not likely to be cost effective because these measures are assumed to be implemented on top of the passive measures.

There are drawbacks to the Alternative Scenario procedure, discussed in more detail below, which are integral to its nature. Basically these result from the extensive detail and statistical precision needed by the methodology. Both technical and socioeconomic details must be specified for a variety of housing types, separate appliance saturations, electrical-fossil comparative efficiencies, prices, etc. These chosen values are often "hypothesized averages" for future years, which are difficult to prove or disapprove. In fact, such sensitive parameters are usually projected by "trending" estimates which do not differ theoretically from conventional trend-forecasting parameters. The Alternative Scenario has many such examples; specifically the methods used for future appliance saturations which were derived from a California specific study (Reference 12). Details of the residential parameters are discussed briefly below.

2.2.2.1 Space-Heating Analysis

Several important assumptions are made which are open to challenge but depend upon informed judgment, and are clearly identified in the Alternative Scenario.

- One-percent each year of the declining stock of existing (pre-1976) dwelling units will convert from fossil to electric space heating.
- 95% of all units built between 1975 and 1995 will have electric space-heat (about 97% of those built during 1990-1995)
- Use of heat pumps, solar systems, and TES will total 15%, 8% and 5% of new single-family residences (SFR/New) by 1995 and 10%, 4% and 10%, respectively, for new multifamily dwelling units (MFD/New). "Retrofit" substitutions will be limited to heat pumps in 5% of the pre-1976 homes stock (SFR/Old).

- SOM Study data on 1974 dwellings was advanced to a 1975 baseline by incrementing by 2%.

- Contributions to system peak from space heating demand were estimated by adjusting the BPA derived peak-to-average factor of 2.98 upward to 3.04 in 1985 and 3.20 by 1995, for various reasons (not detailed fully in text).

The Alternative Scenario derived total space-heat electrical requirements as tabulated in Table 2.2-2. These are compared to equivalent BPA data.

The BPA projections were taken from the SOM Study and made comparable to NRDC results in average and peak megawatts for given years. The SOM Study determined that energy savings (average kWh/yr) from a Strategy 6 conservation policy could lead to a 48% reduction of BPA forecasts for 1995. The Alternative Scenario shows an energy reduction of 44% from BPA's residential space heating projection, so that the two are similar in methods and in results.

2.2.2.2 Analysis of Water Heating, Lighting and Appliances

The procedures used in the Alternative Scenario for the analysis of electric water heating, lighting and electric appliance energy use differ significantly from those used in the BPA projection of February 1976 and those of the SOM Study of July 1976. The Alternative Scenario uses an approach parallel to that applied for the major space heating category, but treats this category identically in all four of the SOM-derived regional prototype dwelling units.

The following points, which condition the "appliances" analysis of the Alternative Scenario, are made:

- There is a serious lack of region-specific detail in numbers, kinds and efficiencies of all appliances used in or forecast for the PNW Region.

- Estimates of future electric efficiencies per unit in the PNW region were made, assuming "reasonable improvements" based upon efficiency improvement rates projected for the State of California by the University of Texas at Austin (Reference 12). See Table 2.2-3 for details.

TABLE 2.2-2

CENTRAL STATION ELECTRICAL

REQUIREMENTS FOR SPACE HEATING

(10^6 kWh/Year)

		1974	1975	1980	1985	1995
Alternative Scenario	- SFR/OLD		8,237		7,660	5,808
	SFR/NEW				3,403	5,381
	MFD/OLD		3,823		2,843	1,915
	MFD/NEW				1,380	2,267
Alternative Scenario	- TOTAL SPACE HEAT		12,060		15,290	15,370
BPA	- SFR/ALL	7,816		11,653		19,456
	- MFD/ALL	3,570		4,095		7,974
BPA	- TOTAL SPACE HEAT	11,386	(12,018)*	15,748	(18,948)*	27,400
TOTAL EQUIVALENTS IN AVERAGE AND PEAK MW/YEAR						
Alternative Scenario	- TOTAL AVERAGE		1,376		1,745	1,755
	TOTAL PEAKING		4,102		5,251	5,441
BPA	- TOTAL AVERAGE	1,300	(1,372)*	1,798	(2,163)*	3,131
	TOTAL PEAKING	N/A	(4,090)*	N/A	N/A	(9,707)*

NOTE: The Alternative Scenario estimates are taken from Reference 3, Tables 7, 29 and 30 and represent a "Strategy 6" conservation policy set. The estimates for SFR/New and MFD/New are slightly in error due to miscalculation in the Alternative Scenario Report. Corrected total requirements are shown in Table 2.2-5.

*BPA peaking capacity is estimated, using 2.98 peak-to-average MW factor. Other BPA values are interpolated (1975, 1985).

TABLE 2.2-3

RELATIVE APPLIANCE ENERGY REQUIREMENTS BETWEEN 1975 AND 2000
(1975 = 1.0)

	POST-1975 (California)	1980 (BPA)	1980 (ORNL)	1985 (NRDC)	1995 (BPA)	1995 (NRDC)	2000 (ORNL)
Appliances							
Refrigerators	.860		.68	1.054		1.031	.50
Cooking Equipment - Electric	.958		.83	.944		.891	.70
Air Conditioning (Room)	-		.80	.75		.60	.65
Other Equipment							
- Freezers	.886		-	.975		.876	-
- Clothes Dryers	.921		-	.937		.937	-
- Television (B/W & CLR)	.554		-	.521		.521	-
- Non-Specified Electrical	-	1.440	-	2.000	2.162	3.000	-
Electric Water Heaters	.958	1.073	.89	.842	1.307	.79	.75

Sources:
- Post-1975 California estimates given in Reference 12, page II-15.
- 1980 and 2000 ORNL data from Reference 13, page 1251.
- 1985 and 1995 NRDC data from Reference 3.
- 1980 and 1995 BPA data obtained by calculations from data given in Reference 4.

- Future saturation levels of appliances were estimated using "California" rates of change, BPA base year data and a "logistic-curve" method of interpolation, with adjustments (8% downward).
- For electric water heating, BPA saturation estimates were used (1974 and 1995), but solar water heating substitutions were assumed to reach 2% and 20% of the 1985 and 1995 projected dwellings.
- A miscellaneous category for all other electric appliances was assumed to grow substantially (300%) and reaches 36% of total appliance electric energy needs in 1995.

With these assumptions and the baseline data tabulated for 1975 in Table 2.2-4 in terms of individual appliances, the Alternative Scenario projects central station average energy requirements for 1985 and 1995. These are compared with BPA estimates given in the SOM Study (interpolated).

Table 2.2-4 shows the Alternative Scenario anticipated 1995 electric demand savings. The most marked savings are projected in water heating at 10,040 million kWh/year, or fully one-half of the BPA forecast. This is partly due to increased water heating unit efficiencies, but also depends upon the assumption that solar water heating units will provide 60% of the hot water demands in all dwellings in which it is implemented (20% in 1995).

The electricity savings in 1995 for all appliances of 13,900 million kWh/year are also large, while the savings of 793 million kWh/year in lighting demands are rather modest. These trends are partly offset by the Alternative Scenario's assumption that the "miscellaneous" category of new appliances and existing "convenience" appliances will grow very rapidly to reach 7,218 million kWh/year.

The Alternative Scenario produces results in overall lighting, appliance and water heating savings which are close to the savings derived by the SOM Study. The SOM Study's Strategy 6 estimated potential savings at 48% of BPA's forecasted demands. The Alternative Scenario projects savings at 41.2% of BPA's forecast for 1995 or 24,733 million kWh/year.

TABLE 2.2-4

CENTRAL STATION ELECTRICAL NEEDS LIGHTING, APPLIANCES AND WATER HEATING IN 10^6 kWh/year

	1974/1975	1980	1985	1995	20-Year Growth (%)
Lighting					
Alternative Scenario	- 3,800	-	3,890	4,540	119.5%
BPA	3,389 (3,435)	3,677	(4,162)	5,333	154.0%
Appliances					
Alternative Scenario	- 9,810	-	13,630	20,100	204.9%
BPA	9,795 (10,586)	15,610	(20,235)	34,000	327.1%
Water Heating					
Alternative Scenario	- 8,730	-	9,550	10,650	122.0%
BPA	8,611 (8,976)	11,044	(15,527)	20,690	230.5%
Total Above					
Alternative Scenario	- 22,340	-	27,070	35,290	158.0%
BPA	21,795 (22,997)	30,331	(39,924)	60,023	
NRDC Average MW/yr.*	2,550	-	3,090	4,029	158.0%
Peak Electric Gen. Capacity (MW)					
Alternative Scenario	- 5,264	-	6,203	7,728	146.8%
BPA	7,414 (7,823)	10,318	(13,581)	20,419	261.0%

*BPA figures in parentheses are interpolations from BPA forecasts given in SOM Study Reference 4, page 274. Source is Table 34 (p. 161) of Reference 3.

Peak electric capacity needs for these residential subsectors are derived in the Alternative Scenario, using multiple peak-to-average parameters. The Alternative Scenario report also projects fossil fuel requirements for certain limited appliances and for water heating to 1995. However, it was found impossible to duplicate the results given in the report. The report also projects that no fossil fuel (natural gas) demands will exist in the appliances category by 1995. This seems rather improbable.

2.2.3 Residential Sector Issues

There is implicit in the Alternative Scenario Analysis a baseline 20-year energy projection for the sector which reflects conditions if none of the scenario's conservation programs are implemented. It is important to compare and contrast the Power Plant Scenario with this hypothetical no-conservation Alternative Scenario. In particular, since the number of households in the region and the regional population are identical in the two scenarios, such a comparison would highlight one very important factor. This is the difference in the business as usual trend projections between the scenarios from the same initial conditions due to different assumptions of future electrical energy demand growth, i.e., rates of conversion from fossil heating to electric heating; appliance saturation and demands; peak-to-average ratios at system peak, etc.

In Table 2.2-5, the projections of electrical energy demand from 1975 to 1985 and 1995 are shown for the Power Plant Scenario, and the Alternative Scenario with and without the implementation of its conservation programs. The following discussion will center on the differences between the baseline projections of the two scenarios in the year 1995, but the comparison is equally valid for the year 1985 as well.

In the space heating category, the baseline Alternative Scenario energy demand is 20% greater than that of the Power Plant Scenario. This is because the number of electrically heated homes in each category (new and old single and multifamily homes) is generally higher in the Alternative Scenario

TABLE 2.2-5

COMPARISON OF RESIDENTIAL SECTOR ENERGY REQUIREMENTS (10^6 kWh) IN THE POWER PLANT SCENARIO (PPS) AND THE ALTERNATIVE SCENARIO (AS) IN 1975, 1985 AND 1995

	1975		1985			1995		
	PPS	AS	PPS	AS* (implicit baseline projection)	AS	PPS	AS* (implicit baseline projection)	AS
Space Heating	12018	12060	18948	20645	15281	27430	32858	15283
Water Heating	8976	8731	15527	11472	9547	20690	15320	10650
Lighting	3435	3804	4162	4599	3893	5333	5908	4544
Appliances	10586	9805	20235	16772	13630	34000	22509	20096
Total Energy Demand	35015	34400	58872	53488	42351	87453	76595	50573
Total Number of Homes in Region	2.289×10^6		2.767×10^6			3.555×10^6		

*Hypothetical scenario derived with the Alternative Scenario forecast methodology and data under the assumption that none of the recommended measures are implemented between 1975 and 1995.

relative to the Power Plant Scenario. As a consequence, the 1995 saturation of electrically heated homes is 69% in the Alternative Scenario and only 60% in the Power Plant Scenario.

In the case of water heating, the Power Plant Scenario shows a 1995 demand of 20.69×10^9 kWh compared to 15.32×10^9 kWh in the baseline Alternative Scenario even though both scenarios assume the same level of saturation (97%). The reason that the consumption is so high in the Power Plant Scenario is the much higher annual average demand per water heater assumed in this scenario relative to the Alternative Scenario (6000 kWh/year versus 4442 kWh/year).

The 1995 lighting energy demand in the two scenarios, while slightly different, can be considered comparable. It appears that the Power Plant Scenario assumes a lower average annual lighting consumption per residence relative to the baseline Alternative Scenario (1500 kWh/year versus 1662 kWh/year). This would account for the difference.

The largest difference between the two scenarios occurs in the Appliance Category. In the Alternative Scenario the average annual appliance energy consumption per residence increases from 4284 kWh in 1975 to 6332 kWh in 1995, approximately a 50% increase. In the Power Plant Scenario, the increase is from 4625 kWh to 9564 kWh, which is over a twofold change in 20 years. Clearly the factors that are responsible for this disparity must be in the different appliance saturation levels and the annual unit appliance energy consumptions assumed in the scenarios. The Alternative Scenario is quite explicit in its assumptions regarding appliances and in fact postulates a rather significant increase in annual demand over the 20 years in the Miscellaneous Category. In contrast, the Power Plant Scenario treats the entire appliance category as a single entity with no disaggregation. Consequently, no specific comparisons are possible except to note that the twofold increase postulated by the Power Plant Scenario appears much too high.

From an overall perspective of the residential sector, the Alternative Scenario projections appear to be more reasonable than those of the Power Plant Scenario. In particular, since the increasingly higher annual unit energy demands for water heaters and appliances in this scenario are unexplained, it does not seem unjustifiable to conclude that this scenario's demands are overestimated.

However, the foregoing discussion presents an important issue that is a key element in the Alternative Scenario Analysis, but which NRDC has chosen not to stress. This is the fact that the baseline no-conservation (i.e., business as usual) trend that is implicit in the Alternative Scenario is considerably lower than that postulated in the Power Plant Scenario. When viewed from this hypothetical baseline rather than from the Power Plant Scenario, the 1995 energy demand differences asserted by NRDC in this sector is reduced by nearly a third. Consequently, the Alternative Scenario results must not be viewed solely with respect to the Power Plant Scenario but must be judged in the context of both the baseline projection differences between the two scenarios and the energy savings potential of conservation that is assumed achievable by NRDC.

2.2.3.1 Peaking Parameters

The Alternative Scenario projects specific central station peak-generation requirements by category for the residential sector. It provides specific peak-to-average multipliers in Tables 30 and 35 for space heating (2.98 to 3.201), for water heating (2.21 to 2.264), for lighting (0.97) and for ten appliance categories ranging from 0.47 (freezers) to 7.33 (refrigerators). The peak-to-average ratio of 7.33 is very high and is possibly an error in reporting by NRDC (i.e., ratios for ranges and refrigerators could have been interchanged by mistake). The reasoning behind these multiple parameters is only briefly discussed.

However, since no comparable contributions to peak load by category in the sector are given by BPA, this comparison between the two scenarios is not possible.

2.2.3.2 Fossil Fuels Estimates

The fossil fuels estimates for the Alternative Scenario represent an additional, unnecessary elaboration of the report's methodology which is based upon end-use analysis of home electrical consumption. In fact, no explanation is provided of the methods used to derive fossil fuel estimates but results are simply presented. These results cannot be duplicated, using any reasonable assumptions to modify the scanty data provided in the Alternative Scenario.

The Alternative Scenario calculates fossil fuel needs for the residential sector in Btu's, using an assumption that the efficiency of fossil-fuel home equipment is only 50% of equivalent 1975 electrical equipment. Thus twice as many Btu's of fossil fuel inputs into typical dwellings are required as the Btu equivalent of annual electric uses, expressed in kilowatt hours. This "thermal:electrical" efficiency factor is improved over time, to 60% for 1985 and 70% for 1995.

The "correct" unit energy consumption levels for gas equipment and appliances are not widely agreed upon. While it is clear that fossil-powered units are less efficient in input-Btu terms, specific equipment varies widely for many reasons. For example, gas-fueled water heaters are usually insulated with only 1-1/4 inches, compared to 2 inches for electric water heaters. Also it is worth recalling that natural gas or fuel oil losses in the distribution process are minimal (say 1-2%), and there is little energy waste in the fossil-fuel production process. In contrast, electrical residential use involves large energy losses in production and transmission/distribution except for hydro-power.

The improvements in fossil-fueled home equipment projected by Oak Ridge National Laboratories are greater than efficiency improvements foreseen by ORNL for major electrical appliances, throughout the 1975-2000 period. For instance, gas space-heating equipment usage will go to 70% of 1975 levels in 1990, while electric goes to 90%. Further, the ORNL model projects that improved equipment efficiencies will cause 57-66% of the possible savings in overall energy use in the residential sector, while higher fuel prices will cause only 18-23% of the reduction (Reference 13). It appears that gas-fueled home equipment is penalized excessively in the Alternative Scenario and that fossil fuel requirements may be overstated due to the implicit unit energy efficiencies used. Since both method and parametric values used are not stated, further comment here is not useful.

2.2.3.3 Other Residential Sector Studies

A number of studies of the residential sector have been made for the PNW and for other regions which may be usefully contrasted to the NRDC methodology. Additional studies are underway also for the region, specifically those conducted for the Northwest Energy Policy Project and by the BPA for its "Rôle EIS" Draft. These latter studies will not be available in time for consideration before July 1, 1977.

In connection with the March 1977 "Need for Power" Seattle hearings of the Nuclear Regulatory Commission, revised NERA forecasts (Reference 14) were presented, and this testimony has been reviewed for its bearing on residential projections.

These projections are based upon an econometric model, prepared for the PNUCC group of utilities in 1975-76 and revised during 1976. The revised model is described in general terms and its results for 1975-1990 in five-year periods are tabulated. Base year is 1972 and comparisons are drawn with the Oregon Department of Energy Model and its results in considerable detail.

Unfortunately the available tables largely represent average annual rates of growth comparisons, which are difficult to interpret and to compare across studies. This fact makes the revised NERA model of little help for this study; however, the model appears to be well constructed and methodologically sound for its purposes. The model depends upon historical correlations and available data for Oregon and Washington States, and judgmental trends for future years are incorporated. It does not allow for policy inputs to model direct effects of conservation and generation policies, and such policies could be incorporated only with difficulty and considerable judgment into the saturation/penetration assumptions and unit electric efficiencies.

The above-mentioned testimony dealt primarily with Oregon and comparisons of the NERA model with the Oregon model forecasts: NERA's overall midpoint projection is for 5.3% yearly growth (AAR) while the DOE projects a 3.49% AAR growth for 1975-1990.(33,391 to 55,900 MWh/year). This is lower than the revised NERA lower forecast. The causes are due to the Oregon Study assumptions of slower population and electric customer (household) growth, plus implicit assumptions that industrial electric uses will increase output/energy efficiencies and limit price-induced fuel switchovers to electric power.

The NERA model deals explicitly with the four private utilities in the PNUCC/West Group Area. In 1975 these utilities provided 33.6% of Washington State's actual load (e.g. 16,653 kWh/year). The NERA tables do not show residential, commercial and industrial demands separately, and do not show how the utilities' loads were factored to translate service areas into statewide totals.

Econometric models are particularly useful for simulations with a variety of assumptions about such basic parameters as forecasted population, employment, household formation, and purchasing habits--the underlying cause of electric saturation estimates. However, it is often difficult to relate or compare an econometric model to deterministic models such as the Alternative Scenario, or to trend projection models such as the BPA forecast of February 1976 or projections presented by the Federal Power Commission to the Nuclear Regulatory Commission (Reference 15).

The Alternative Scenario and the BPA forecast are based upon identical basic parameters, as is true for the SOM Study as well. Therefore these studies can be usefully compared and analyzed for the residential sector. The discussion above has pointed out flaws in the Alternative Scenario. However, it has also demonstrated that many assumptions of the scenario are valid and are improvements upon methods followed in the BPA forecast and in the SOM Study. On balance it appears that the projected conservation savings for the two decades to 1995 are not unreasonable, as adjusted in this study.

2.3 COMMERCIAL SECTOR DESCRIPTION AND ANALYSIS

The computations which result in the commercial sector portion of the Alternative Scenario were reconstructed from the data and procedures specified in Reference 4. Figure 2.3-1 is a schematic representation of the computational procedure for the commercial sector.

Building Type	Commercial Floor Space	x	Energy Intensity	x	(1 - % Savings From Conservation)	=	Net Energy Consumption
Small Office Large Office Retail School Other	Data given by year and office type (fossil and electrical).		Data given for each office type (kWh/ft^2).		Data given by year and office type.		- - - - - Σ_1 = total energy consumption before on-site generation

- Saving due to on-site generation (solar, TES) = percentage of Σ_1 (data given for each year for solar and TES).
- Final Electrical Energy Consumption = $(\Sigma_1 - S)$ x Electrical Saturation.

FIGURE 2.3-1. COMMERCIAL SECTOR COMPUTATIONAL PROCEDURE

Examination of this procedure shows, as was the case with the residential sector, that there is an implicit projection of energy requirements before conservation initiatives are applied, incorporated in the methodology. This can be computed by following the steps shown in Figure 2.3-1, but deleting the conservation improvements (i.e., "% savings from conservation" = 0). The details of these calculations are discussed in the following paragraphs.

2.3.1 Alternative Scenario Projection of Energy Consumption Before Conservation

The energy consumption for the commercial sector before the implementation of conservation was computed on the basis of energy consumption by building type. The Alternative Scenario computed this on the basis of its projections of regional floor space by building type but utilizing energy intensities (kWh/ft^2) by building type taken from the SOM Study, Reference 4. These calculations are not given explicitly in the Alternative Scenario report and so the difference between the energy consumption before and after the implementation of conservation is not made explicit there. The calculations and results are given herein in the first four columns of Tables 2.3-1 and 2.3-2 for 1985 and 1995, respectively.

The Alternative Scenario first projects the growth in total regional commercial floor space according to the growth in federal plus "non-basic" employment as given by BPA. The total commercial floor space was then allocated among the various building types in the same proportion as the forecasted national percentages given in Reference 4. Since the Alternative Scenario projected commercial floor space is the total floor space and not merely the fraction that would be electrically heated and yet is applied to projected electric intensities from the SOM Study that strictly speaking should apply to only "all-electric" buildings, the resulting electrical energy consumption forecast for the commercial sector is a purposeful overestimate at this point.[1] Therefore, this computed so-called "total effective electrical consumption" has to be converted to actual electrical

[1] It is mathematically correct to use an electric intensity factor rather than a total intensity (electric + fossil) factor since the correction is applied at the end of the calculation. It would have been more straightforward (but equivalent) to immediately connect total floor space to "electrical" floor space, than multiply by the electric intensity factor.

TABLE 2.3-1
1985 COMMERCIAL SECTOR ANALYSIS

(1) BUILDING TYPE	(2) COMMERCIAL SPACE (X 10^6 ft^2) Alternative Scenario[1]	(3) ENERGY INTENSITY (kWh/ft^2) (SOM)[2]	(4) ENERGY USE (X 10^6 kWh) Alternative Scenario	(5) % SAVINGS (SOM)[2]	(6) ENERGY SAVINGS (X 10^6 kWh) Alternative Scenario	(7) NET ENERGY CONSUMPTION (X 10^6 kWh) Alternative Scenario
Small Office	125.1	74.3	9,295	31.32	2,911	6,384
Large Office	125.1	84.7	10,596	37.2	3,942	6,654
Retail	312.75	72.0	22,518	18.8	4,233	18,285
School	225.18	20.1	4,526	22.3	1,009	3,517
Other Commercial	462.87	42.6	19,718	21.6	4,259	15,459
TOTAL	1,251.00	Avg. 53.3				
Total Effective Electrical			66,653		16,354	50,299
Total Electrical Saturation			.423		(24.5%)	.423
Actual Electrical Consumption			28,194			21,276
BPA Electrical Consumption[2]			30,800			

[1] Reference 3.
[2] Reference 4.

TABLE 2.3-2
1995 COMMERCIAL SECTOR ANALYSIS

(1) BUILDING TYPE	(2) COMMERCIAL SPACE (X 10^6 ft^2) Alternative Scenario[1]	(3) ENERGY INTENSITY (kWh/ft^2) (SOM)[2]	(4) ENERGY USE (x 10^6 kWh) Alternative Scenario	(5) % SAVINGS (SOM)[2]	(6) ENERGY SAVINGS (x 10^6 kWh)	(7) NET ENERGY CONSUMPTION (x 10^6 kWh)
Small Office	161.91	74.3	12,030	43.3	5,209	6,821
Large Office	161.91	84.7	13,714	82.9	11,369	2,345
Retail	447.18	72.0	32,197	25.5 (52)[3]	8,210 (16,742)[3]	23,987 (15,454)[3]
School	246.72	20.1	4,959	50.2	2,489	2,470
Other Commercial	524.28	42.6	22,334	48.4	10,810	11,524
TOTAL	1,542.00	Avg. 55.3		Avg. 45.1		
Total Effective Electrical			85,234		38,130 (44.7%)	47,147 (38,614)[3]
Total Electrical Saturation			.461			.461
Actual Electrical Consumption			39,293			21,735 (17,801)[3]
BPA Electrical Consumption			50,200			

[1] Reference 3.
[2] Reference 4.
[3] Represents corrected version of Alternative Scenario.

consumption in order to be meaningful. Although the Alternative Scenario procedure continues to use units of total effective electrical consumption throughout the calculations and does not convert until the final step, it was converted here immediately in order to compare with BPA's projections before conservation--a comparison not made explicitly in the Alternative Scenario report, as mentioned above. The conversion factors are total electrical saturation factors which are independently forecasted in the Alternative Scenario assuming a linear .6% per year conversion rate from non-electrical (fossil) to electrical energy usage. When this conversion to actual electrical consumption is made, the before conservation projections are slightly lower than those provided by BPA for 1985 (28.2 versus 30.8 billion kWh) and significantly lower for 1995 (39.2 versus 50.2 billion kWh). Since the Alternative Scenario independently projects floor space and saturation values for the region, its baseline energy forecast (the starting point from which reductions due to conservation are applied) is different (and lower) from that given by BPA. The significant difference between the Alternative Scenario implicit baseline consumption and the BPA forecast highlights the importance of developing sound business-as-usual forecasting methods.

Table 2.3-3 presents SOM floor space projections for electrically heated buildings and Alternative Scenario projections for all buildings in the sector as well as electrically heated buildings. SOM projections are shown for each building type for 1980 and 1995. The equivalent 1985 projections were estimated in this study. In both 1985 and 1995 the Alternative Scenario projections for electrically heated floor space are significantly lower than those projected by SOM. These lower floor space projections account for the lower before conservation energy forecasts in the Alternative Scenario.

2.3.2 Alternative Scenario Projection of Energy Consumption After Implementation of Building Conservation

The building conservation measures adopted by the Alternative Scenario were exactly the same as those given in the SOM Study Strategy #6, under the mandatory implementation program (these were the strongest conservation measures that were still cost-effective to implement according

TABLE 2.3-3

COMPARISON OF SOM AND NRDC COMMERCIAL FLOOR SPACE PROJECTIONS

BUILDING TYPE	1980 UNIT FLOOR SPACE (ft2)	1980 # UNITS	1980 SOM TOTAL (X 10^6 ft^2)	1980 NRDC TOTAL (1985) (X 10^6 ft^2)	1995 # UNITS	1995 SOM TOTAL (X 10^6 ft^2)	1995 NRDC TOTAL (X 10^6 ft^2)
Small Office							
Existing	1,500	13,453	20.2		13,453	20.2	
New	1,500	7,175	10.8		28,700	43.0	
Total			31.0	125.1		63.2	161.91
Large Office							
Existing	50,000	236	11.8		236	11.8	
New	50,000	118	5.9		496	24.8	
Total			17.7	125.1		36.6	161.91
Retail							
Existing	49,986	889	44.4		889	44.4	
New	49,986	500	25.0		1,973	98.6	
Total			69.4	312.75		143.0	447.18
School							
Existing	44,925	3,212	144.3		3,212	144.3	
New	44,925	1,650	74.1		6,091	273.6	
Total			218.4	225.18		417.9	246.72
Other Commercial							
Existing	36,754	3,577	131.5		3,577	131.5	
New	36,754	1,724	63.4		6,578	241.8	
Total			194.9	462.9		373.3	524.3
GRAND TOTAL			531.4 (698.9 in 1985)	1,251.0 529.2[1]		1,034.0	1,542.0 710.8[2]

[1] The corresponding electrical floor space for 1985 is 529.2.

[2] The corresponding electrical floor space for 1995 is 710.8.

to the SOM Study). The percentage of energy savings over the no-conservation case could be determined by adding the kWh savings from both existing and new buildings of each building type and dividing by the total amount of electrical energy that would be consumed if no conservation were implemented. These percentages were computed based on the data given in the SOM Study for 1980 and 1995. The computed percentages matched those given in the Alternative Scenario report for 1995 (except for retail buildings which will be discussed), and the 1985 values fall between the 1980 and 1995 values and so were assumed to be interpolated. Only these percentage savings were applied in the Alternative Scenario and not the actual kWh savings. This was due to the fact that the total electrical commercial floor space by building type was different in the two scenarios as discussed in the previous section.

Based on these percentage savings the actual electrical energy savings could be computed by applying these percentages to the total effective electrical consumption by building type computed by the Alternative Scenario. From this result the net energy consumption (consumption after conservation is taken into account) can be determined by subtracting the savings from the energy consumption before conservation is implemented. These calculations are shown in columns 5, 6, 7, Tables 2.3-1 and 2.3-2. After summing the net energy consumptions by building type over all the building types, the total energy consumption expressed as total effective electrical consumption for the commercial sector is obtained. These sums are shown near the bottom of column 7 on Tables 2.3-1 and 2.3-2. Note that it would be invalid to compare these values at this point to BPA's values for total electrical energy consumption in the commercial sector for the years 1985 and 1995, since the comparison would not take into account electrical saturation effects.

Several numerical or data citation errors were discovered in the course of reconstructing this part of the Alternative Scenario. The figure of 50.2 billion kWh attributed to BPA by the Alternative Scenario report for the 1995 commercial sector consumption is not correct. The correct figure is 44.2 billion kWh as given in the SOM Study on p. 121 from data supplied by BPA.

Two other computational errors are discussed below.

1. RETAIL BUILDINGS - An error in the SOM Study analysis of retail buildings was inadvertently incorporated in the Alternative Scenario analysis. On page 165 of the SOM Study, a total savings of 3,622 $\times 10^6$ kWh for new retail buildings in 1995 is shown. This consists of 2,734 $\times 10^6$ kWh saved due to mandatory compliance with the ASHRAE 90-75 building codes plus 888 $\times 10^6$ kWh due to other miscellaneous mandatory conservation measures. Yet in the summary

table on page 121, only this latter 888 x 10^6 kWh savings is shown resulting in a 25.5% savings for retail buildings rather than a 52% savings for retail buildings based on the correct savings of 3,622 kWh. Unfortunately, the Alternative Scenario Study uses the incorrect value of 25.5% in its calculations as cited in page 52 of Reference 3.

2. STREET LIGHTING - This category of energy consumption was neglected in the Alternative Scenario report. The category labeled "Other" refers solely to "Other Commercial" in the SOM report and does not include "Street Lighting." This can be verified by calculating the percentage savings due to "Other Commercial" and then "Other Commercial" plus "Street Lighting," which are 48.36 and 45.8, respectively. The former value is the one cited in the Alternative Scenario Study (Reference 3, page 52).

Two other general methodological problems are described here. First projecting energy consumption according to total energy intensities by building type rather than according to end-use service (as is done in the residential sector) is not the best projection method. However, since data were not available by end-use service consumption in the PNW commercial sector, this could not be avoided. Secondly, the conservation strategy adopted from the SOM Study assumes implementation in 100% of all commercial buildings by 1995. This assumption may be questioned even for a mandatory conservation program in terms of its economic and institutional feasibility (discussed further in Section 4.5).

The resolution of the problem with street lighting is presented in Table 2.3-4 wherein the energy consumption and savings projected in the SOM Study under Strategy #6 (the strategy adopted by the Alternative Scenario for commercial building conservation) are given. The 1985 values are interpolated assuming an exponential implementation rate between 1980 and 1995.

When this street lighting consumption data is incorporated together with the correction to the retail building consumption data, a revised or

TABLE 2.3-4

PROJECTED STREET LIGHTING CONSUMPTION AND SAVINGS[1]

($X\ 10^6$ kWh)

LIGHTING TYPE	1980 ENERGY USED	1980 ENERGY SAVED	1985 ENERGY USED	1985 ENERGY SAVED	1995 ENERGY USED	1995 ENERGY SAVED
Existing	500	115	500	115.0	500	115
New	300	69	489[2]	112.5	1,300	299
TOTAL	800	184	989	227.5	1,800	414
NET CONSUMPTION ($X\ 10^6$ kWh)	616		761.5		1,386	

[1]Data for 1980 and 1995 taken from SOM Study (Reference 4, pages 120 and 121).

[2]Interpolated values between 1980 and 1995 based on an exponential implementation rate between the two years with an average 1,450 kWh/lighting unit consumption.

corrected Alternative Scenario projection is obtained. In Table 2.3-5, a corrected scenario for the commercial sector is presented alongside the uncorrected, as given, version. The result is that in 1985 the correct consumption is slightly higher (4%) than the uncorrected value, whereas in 1995 the correct consumption is somewhat lower (12%) than the uncorrected value. This corrected scenario is only valid up to this point in the reconstruction of the entire scenario. In particular, the further savings due to on-site energy sources have not yet been accounted for. However, the corrected scenario will be carried along through completion of the scenario reconstruction in the remaining sections.

TABLE 2.3-5

CORRECTED ALTERNATIVE SCENARIO FOR THE COMMERCIAL SECTOR*

ENERGY CONSUMPTION CATEGORY (X 10^6 kWh)	1985		1995	
	UNCORRECTED	CORRECTED	UNCORRECTED	CORRECTED
Retail Buildings	18,285	18,285.0	23,987	15,454
Other Commercial Buildings	32,014	32,014.0	23,160	23,160
TOTAL EQUIVALENT	50,299	50,299.0	47,147	38,614
TOTAL ACTUAL (Saturation .423, .461 in 1985, and 1995)	21,276	21,276.0	21,735	17,801
Street Lighting	0	761.5	0	1,386
GRAND TOTAL	21,276	22,037.5	21,735	19,187
% CHANGE	+3.6%		-11.6%	

*Does not include conservation due to on-site energy sources.

2.3.3 Alternative Scenario Projection of Energy Consumption after Implementation of On-Site Energy Sources

The Alternative Scenario also includes a small amount of on-site energy sources which reduce the sector's dependence on central station sources. These on-site sources consist of solar systems and total energy systems which reduce the total effective electrical consumption by the same amount in which they are implemented:

	1985	1995
Solar	1%	5%
TES	2%	10%

The effects of these further conservation measures on the total effective electrical consumption of the sector are shown in Table 2.3-6 which completes the definition of the (corrected) Alternative Scenario.

TABLE 2.3-6

SUMMARY OF COMMERCIAL SECTOR ANALYSIS ACCORDING TO THE ALTERNATIVE SCENARIO

	1985	1985 (Corrected)	1995	1995 (Corrected)
Total Effective Electrical Energy Implicit Baseline (X 10^6 kWh)	66,653	66,653	85,234	85,234
Total Effective Electrical Energy After Building Conservation (X 10^6 kWh)	50,299	52,098	47,147	41,620
Percentage On-Site Generation:				
Solar	1%	1%	5%	5%
TES	2%	2%	10%	10%
Amount Saved from On-Site Generation:				
Solar	503	521	2,355	1,931
TES	1,006	1,042	4,710	3,861
TOTAL	1,509	1,563	7,065	5,792
Total Effective Electrical Energy After On-Site Generation (X 10^6 kWh)	48,790	50,535	40,082	35,828
Total Effective Electrical Saturation	.423	.423	.461	.461
Actual Electrical Consumption (X 10^6 kWh)	20,638	21,376	18,478	16,517
% Change		+3.6%		-10.5%

The corrected versions of the Alternative Scenario show that the error is somewhat low for 1985 and somewhat high for 1995. These differences are not of sufficient magnitude to affect any conclusions, and are not considered in the economic analysis of this sector (3.6).

There are, however, other general methodological problems. Although it is stated in Table 14 of the Alternative Scenario report that the implementation of the on-site energy systems provide the stated fractions of the heating requirements, these fractions were nevertheless applied to the total effective electrical consumption after the implementation of building conservation, as shown in the summary given in Table 2.3-6. Thus the table is mislabeled relative to how these systems were actually implemented in the scenario. The stated procedure would have been a more logical assumption.

In terms of the manner in which the Alternative Scenario results are presented, it is suggested that the following summary Table 2.3-7 would be more perspicuous. This table immediately reveals that while the implicit baseline projections are only slightly lower than BPA/SOM in 1985, they are much lower in 1995 and, more significantly, that the absolute magnitude of the savings are only slightly greater than SOM's for both years. This latter result should not be unexpected since the Alternative Scenario used SOM's percentage savings by building type to which was added only a modest amount of on-site systems. Thus, while the Alternative Scenario projected energy savings are significant (20.8 billion kWh in 1995), they are not significantly greater than those obtained in at least one other study, and certainly are not as great as would appear from a direct comparison of BPA and Alternative Scenario projections in any given year (e.g., 50.2 versus 20.8 billion kWh in 1995).

TABLE 2.3-7

COMPARISON OF ALTERNATIVE SCENARIO AND BPA/SOM ELECTRICAL REQUIREMENTS (10^6 kWh) FOR THE COMMERCIAL SECTOR OF THE PNW

	1985			1995		
	BEFORE CONSERVATION[1]	AFTER CONSERVATION	SAVINGS[2]	BEFORE CONSERVATION[1]	AFTER CONSERVATION	SAVINGS
BPA/SOM	30,800	24,224	6,576	50,200/44,200[3]	30,660/24,660	19,540
ALT. SCENARIO	28,194	20,638	7,556	39,293	18,478	20,835

[1] "Implicit baseline" projection for Alternative Scenario.

[2] The 1985 values for BPA/SOM savings were interpolated exponentially between the 1980 and 1995 values given in Reference 4, p. 120, for the mandatory implementation program.

[3] The slash between the figures indicates the BPA versus the SOM figures, respectively. Only the BPA before conservation figure and the Alternative Scenario after conservation figure are given explicitly in the Alternative Scenario.

2.3.4 Summary and Conclusions of Commercial Sector Description

The primary prupose of this section was to attempt to reconstruct the Alternative Scenario commercial sector from the data and procedures specified in the report. Although some problems with the data, computational procedure, and methodology were discovered in the course of this reconstruction, these problems are not believed to significantly affect their overall results. Indeed, they show that the energy savings derived on the basis of the assumptions made and procedures used result in a conservative net error in 1995 (see Table 2.3-6). As noted, much of the reason for the lower energy projection vis-a-vis BPA's estimated requirements stems from a lower (implicit baseline) projection of energy requirements. A schematic of the projected electricity requirements for this sector for the two scenarios is presented in Figure 2.3-2.

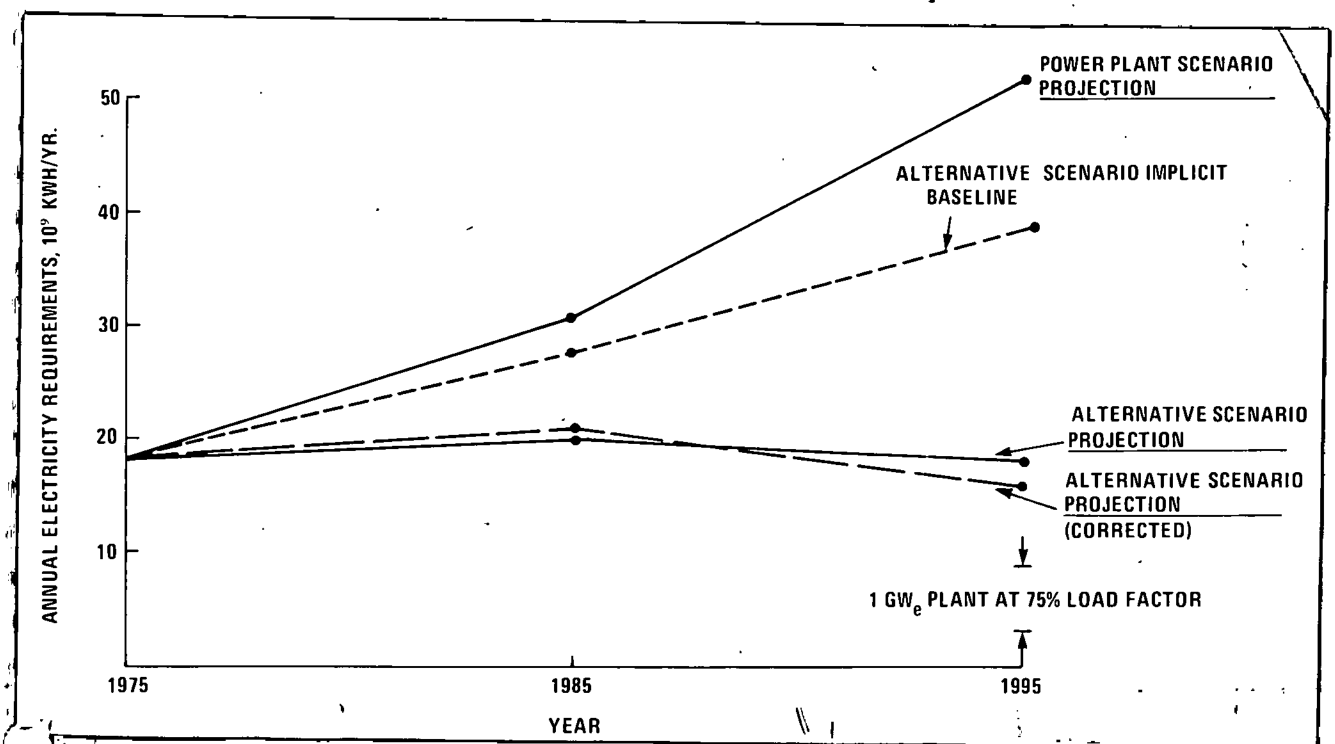


FIGURE 2.3-2. COMPARISON OF ELECTRICAL ENERGY CONSUMPTION FORECASTS FOR THE COMMERCIAL SECTOR OF THE PNW, 1975-1995

Next, it should be noted that the final actual electrical consumption determined depends critically on the electrical saturation values the Alternative Scenario projects. For example, if the saturation values were 1.0 in 1985 and 1995, then the total actual electrical consumption would equal the total effective electrical consumption (the latter values are shown on the fourth row from the bottom in Table 2.3-6). If this were the case, then the Alternative Scenario would produce higher projections than BPA's for the commercial sector for 1985 (48.8 versus 30.8 billion kWh) and, while the projections would be lower than BPA's for 1995 (40.0 versus 50.2 billion kWh), they would be more than twice as high as the Alternative Scenario actually forecasts. Hence the assumption of a constant .6% rate of electrical substitution on which the forecasted saturations were based is critical.

It is noted in the Alternative Scenario report that differences between the scenario and BPA projections are the result of the savings achieved by the adoption of the Alternative Scenario efficiency improvement measures and different projections of energy requirements, apart from those measurements. Nevertheless it is misleading to present the final projected consumption figures in juxtaposition to BPA's projected figures without also presenting the (implicit) baseline forecast (before conservation is implemented). As presented, the misleading impression is given that the conservation scenario represents an energy savings from that of BPA's rather than from a different (unstated) baseline projection.

2.4 MANUFACTURING SECTOR DESCRIPTION AND ANALYSIS

The Manufacturing Sector in the Pacific Northwest region comprises a variety of industries as shown in Table 2.4-1. In 1975 this sector's energy requirements represented 48% of the region's electrical energy demand and 44% of the fossil energy demand, making it the largest of the four energy consuming sectors in the Northwest. Two dominant industries in this sector from an energy viewpoint are the primary aluminum industry and the paper and allied products industry. Primary aluminum production in 1975 was responsible for over 50% of the sector's electricity demand, and the paper industry accounted for over 25% of the sector's

TABLE 2.4-1

PNW MANUFACTURING SECTOR ENERGY REQUIREMENTS IN 1975

SUBSECTOR NUMBER	INDUSTRY	BPA ELECTRICITY[1] (10^9 kWh)	ALTERNATIVE SCENARIO ELECTRICITY[2] (10^9 kWh)	ALTERNATIVE SCENARIO FOSSIL FUELS[3] (10^{12} Btu)
1	Food & Kindred Products	1.33	1.4840	46.200
2	Textiles & Apparel	-	0.03146	-
3	Lumber & Wood Products	4.22	4.0890	49.150
4	Paper & Allied Products	6.79	6.5490	95.190
5	Printing & Publishing	-	0.1427	1.575
6	Chemicals & Allied Products	3.21	4.7820	18.130
7	Petroleum & Coal Products	-	0.6424	59.910
8	Stone, Clay & Glass	-	0.5688	18.680
9	Iron & Steel	0.72	1.2060	17.280
10	Non-Ferrous, Non-Aluminum	1.72	2.1860	14.240
11	Primary Aluminum	26.85	27.2900	4.300
12	Fabricated Aluminum	-	0.2642	3.308
13	Machinery & Electrical Equipment	-	0.4756	5.314
14	Aerospace Equipment	-	0.7619	8.536
15	Other Transportation Equipment	-	0.2808	2.677
	Other Manufacturing	7.40[4]	1.8540	14.170
	TOTAL	52.24	52.6000	358.700

[1]Calculated from 1974 actual industrial electricity use data and projections of industrial electricity use to 1980 given in Reference 4, p. 182.

[2]Reference 3, Table 45, p. 176. Includes on-site generation existing in 1975 in subsectors 3, 4 and 7 to the extent of 10%, 60% and 10% of the respective total electrical energy requirements.

[3]Reference 3, Table 23, p. 73.

[4]Includes electricity requirements of subsectors 2, 5, 7, 8 and 12 through 15.

fossil energy demand. While the paper industry's electrical energy requirement ranks second only to that of the primary aluminum industry, it has the distinction of producing over half its power on-site (60% in 1975), purchasing only the remaining.

The estimation of electrical energy requirements in future years from the perspective of generation planning has traditionally been in the domain of the electric utilities. Such estimations usually rely on past consumption patterns with some modifications, and almost always represent a business as usual trend. This appears to have been the case in projections of the manufacturing sector's electricity demands in 1985 and 1995 in the Power Plant Scenario. In contrast, the Alternative Scenario included an almost zero-based projection of these same future demands for each subsector and derived consumption patterns significantly different from those of BPA.

It is the purpose of this section to analyze the Alternative Scenario energy projections in the manufacturing sector to 1985 and 1995 and critically evaluate both the methodology and results of the two projections.

The 1975 total electrical energy requirements (including on-site generation) of the individual subsectors of the manufacturing sector are shown in Table 2.4-1. The BPA 1975 electricity demands were derived from actual consumption data in 1974 and projections to 1980 given in the Skidmore, Owings & Merrill Study (Reference 4). This procedure could account for the differences between individual BPA and Alternative Scenario subsector demands in 1975 evident from Table 2.4-1. Rather than highlighting these differences in 1975, the intent of Table 2.4-1 is to show the much higher level of disaggregation that the Alternative Scenario provides in the sector. Table 2.4-1 also shows the 1975 fossil energy requirements of each subsector as given in the Alternative Scenario. BPA has provided no estimates of the fossil energy demands in any of the subsectors since their concern is primarily with electricity demand.

The Alternative Scenario analysis of future electrical energy requirements for the manufacturing sector in the period 1975 through 1995 is based on the following six assumptions:

a. During the 20-year period of the scenario, improvements in the energy efficiency in the entire manufacturing sector would reduce the amount of energy used per unit of product by 20% (Reference 3, p. 56). Of this reduction, one-fifth or 4% is assumed to occur by 1985 (Reference 3, p. 61).

b. Substitution of electrical energy will occur for the entire non-electrical energy portion of the manufacturing sector at a linear rate of 0.6% per year (Reference 3, pp. 62 and 171).

c. Substitution of energy (electrical and non-electrical) for labor will occur at a linear rate of 1% per year between 1971 and 1995 (Reference 3, p. 62).

d. Small increases in on-site generation of electricity will occur either by self-generation or by using wastes. The subsector designated "other manufacturing" would rely on self-generation for 2% of its total electrical energy needs in 1985 and 8% in 1995. In the lumber and wood products industry, the fraction of total electrical energy requirements from waste generation would increase from 10% in 1975 to 20% in 1985 and 30% in 1995. The paper and allied products industry and the petroleum and coal products industry would continue to maintain on-site generation capability at 60% and 10% of their total electrical energy requirements, respectively (Reference 3, pp. 63 and 177).

e. The supply of electrical energy by BPA to the aluminum industry would be phased down over the period 1985-1993 as present firm power contracts for plants 35 years or older expired over this time frame. Only two of ten existing plants would continue operation with BPA power beyond 1995. These two plants (Intalco at Ferndale, WA, and Martin Marietta at Goldendale, WA) account for 23% of the present regional aluminum production capacity or 7% of national capacity (Reference 3, pp. 79 and 80).[1]

[1] The Alternative Scenario yields an energy surplus by 1995, which would be sufficient to retain the aluminum industry if that option were selected. Availability of this surplus energy is, however, contingent upon the successful achievement of the rates of growth and rates of conservation implementation defined in the scenario.

f. Employment is the fundamental determinant of future electrical needs in the manufacturing sector. The total employment projected for 1885 and 1995 under the scenario is identical to the BPA projections but distributed over the manufacturing subsectors in proportions different than those given by BPA (Reference 3, p. 66). Except in the aluminum industry, where the projected level of employment would decrease by 77% between 1985 and 1995, the employment levels in each subsector of the modified manufacturing mix do not vary from BPA's projections by more than 12% in 1995 (Reference 3, p. 64).

The reconstruction of the manufacturing sector energy requirements in 1985 and 1995 using the Alternative Scenario assumptions described is detailed below. The Alternative Scenario and BPA stipulated subsector employment levels in 1975, 1985, and 1995 are shown in Table 2.4-2. The Alternative Scenario assumption of linear rates of change in fossil and electrical energy consumption due to substitution effects are assumed to start to apply to the 1975 fossil and electricity demands in each subsector, rather than the implied baseline year of 1971. The effect of this interpretation does result in small but consistent differences between this study and the Alternative Scenario results. The overall effect is negligible.

Two algorithms incorporating the Alternative Scenario assumptions were developed to compute 1985 and 1995 fossil and electrical energy requirements in each subsector. The fossil energy consumption in subsector j is given by:

$$F^j_{1975+\Delta T} = \left\{F^j_{1975} - (0.006) x \Delta T x F^j_{1975} + (0.01) x \Delta T x F^j_{1975}\right\} x (1-\Delta e) x R_{1975+\Delta t}$$

where,

F^j_{1975} = 1975 fossil energy consumption in subsector j, Btu's

ΔT = 10 for 1985 and 20 for 1995

Δe = Fractional decrease in energy demand due to conservation; 0.04 for 1985 and 0.20 for 1995

R_{1985} = NRDC ratio of 1985 to 1975 employment levels in subsector j

R_{1995} = NRDC ratio of 1995 to 1975 employment levels in subsector j

TABLE 2.4-2

MANUFACTURING SECTOR EMPLOYMENT[1]
(in 10^3)

SUBSECTOR NUMBER	1975 EMPLOYMENT NRDC & BPA (in 10^3)	RATIO OF 1985/1975 EMPLOYMENT LEVELS NRDC	BPA	RATIO OF 1995/1975 EMPLOYMENT LEVELS NRDC	BPA
1	69.2	1.0884	1.0853	1.1642	1.1517
2	13.6	1.2412	1.2132	1.5081	1.3971
3	135.6	0.9735	0.9801	0.7876	0.8024
4	28.2	1.0528	1.0603	1.0475	1.0674
5	22.7	1.3247	1.2952	1.7119	1.5859
6	10.9	1.2211	1.2294	1.3862	1.4128
7	3.0	1.2843	1.3333	1.3543	1.5333
8	11.2	1.2232	1.2321	1.4018	1.4286
9	8.5	1.1800	1.1882	1.2588	1.2824
10	4.9	1.1551	1.1633	1.2618	1.2857
11	14.4	0.9965	1.1806	0.2294	1.2708
12	20.4	1.3637	1.3333	1.7250	1.5980
13	48.9	1.4370	1.4049	1.9051	1.7648
14	52.6	1.2070	1.2034	1.3837	1.3688
15	28.3	1.3601	1.3428	1.6809	1.6007
16	23.9	1.4017	1.3975	1.8322	1.7782
TOTAL	496.3	1.1654	1.1654	1.2569	1.2569

[1] NRDC Report, Table 17, p. 66 (Reference 3).

The first term of the equation represents the change in 1975 fossil energy consumption in subsector j due to substitution with electricity and substitution for labor, and indicates the consumption level with all other factors remaining unchanged (i.e., no conservation and no growth in subsector output). The second term captures the change in fossil energy consumption if conservation programs were implemented. The last term which is the employment ratio relative to 1975 is a surrogate multiplier, which was assumed to be equivalent to the ratio of subsector output relative to 1975. Although this assumption is not made explicitly clear in the Alternative Scenario Report, it is implied in their assumption on employment effects on energy consumption (Assumption (vi)).

It is interesting to note that the Alternative Scenario employment ratio is less than 1 only in two subsectors both in 1985 and 1995. These subsectors are the lumber and wood products and the primary aluminum industries. The Alternative Scenario assumes the aluminum industry to be phased down substantially by 1995 starting from October 1986. BPA, however, assumes continued growth in this subsector. There is no explanation either from BPA or the Alternative Scenario to why the employment in the lumber industry declines.

The electrical energy consumption in subsector j is given by:

$$E^j_{1975+\Delta t} = \left\{ E^j_{1975} + E_{1975+\Delta T} + (0.01) x \Delta T x E^j_{1975} \right\} x (1-\Delta e) x R_{1975+\Delta t}$$

Where

E^j_{1975} = 1975 electrical energy consumption in subsector j in kWh

$E_{1975+\Delta t}$ = Electrical equivalent of fossil energy substituted in kWh

= $\left\{ (0.006) \times \Delta t \times F^j_{1975} \times 0.67/3412 \right\}$ by Alternative Scenario definition

The results of calculated subsector energy requirements for 1985 and 1995 and those given in the Alternative Scenario Report are compared in Tables 2.4-3 and 2.4-4. The differences between the two in the total energy requirements are about 1% in 1985 and about 3% in 1995. These differences are small and arise for reasons stated earlier.

TABLE 2.4-3
MANUFACTURING SECTOR ENERGY REQUIREMENTS IN 1985

SUBSECTOR	FOSSIL ENERGY (10^{12} Btu)		TOTAL ELECTRICITY (10^9 kWh)		CENTRAL STATION REQUIREMENT[1] (10^9 kWh)	
	CALCULATED	ALTERNATIVE SCENARIO	CALCULATED	ALTERNATIVE SCENARIO	CALCULATED	ALTERNATIVE SCENARIO
1	50.2	49.67	2.274	2.338	2.274	2.338
2	-	-	0.04123	0.04108	0.04123	0.04108
3	47.77	47.24	4.745	4.795	3.796	3.836
4	100.06	98.98	8.415	8.528	3.366	3.411
5	2.08	2.061	0.2232	0.2254	0.2232	0.2254
6	22.10	21.85	6.417	6.424	6.417	6.424
7	76.82	76.69	1.742	1.838	1.568	1.654
8	22.81	22.57	0.993	1.023	0.993	1.023
9	20.36	20.14	1.733	1.757	1.733	1.757
10	16.42	16.24	2.853	2.866	2.853	2.866
11	4.28	4.232	28.77	28.67	28.77	28.67
12	4.50	4.455	0.4315	0.4364	0.4315	0.4364
13	7.94	7.541	0.8079	0.8161	0.8079	0.8161
14	10.29	10.17	1.088	1.099	1,088	1.099
15	3.64	3.595	0.444	0.448	0.444	0.448
16	19.83	20.02	2.969	2.986	2.910	2.927
TOTAL	409.1	405.5	63.95	64.29	57.72	57.97

[1]After subtracting on-site generation in subsectors 3, 4, 7 and 16.

TABLE 2.4-4

MANUFACTURING SECTOR ENERGY REQUIREMENTS IN 1995

SUBSECTOR	FOSSIL ENERGY (10^{12} Btu)		TOTAL ELECTRICITY (10^9 kWh)		CENTRAL STATION REQUIREMENT[1] (10^9 kWh)	
	CALCULATED	ALTERNATIVE SCENARIO	CALCULATED	ALTERNATIVE SCENARIO	CALCULATED	ALTERNATIVE SCENARIO
1	46.47	45.0	2.672	2.886	2.672	2.886
2	-	-	0.04555	0.04526	0.04555	0.04526
3	33.45	32.38	3.821	3.962	2.675	2.773
4	86.15	83.41	8.465	8.839	3.386	3.535
5	2.33	2.256	0.285	0.2951	0.285	0.2951
6	21.71	21.02	6.838	6.903	6.838	6.903
7	70.10	69.21	2.365	2.684	2.129	2.416
8	22.62	21.9	1.259	1.363	1.259	1.363
9	18.79	18.2	1.867	1.949	1.867	1.949
10	15.52	15.03	2.987	3.045	2.987	3.045
11	0.8524	0.8255	6.029	5.995	6.029	5.995
12	4.930	4.773	0.545	0.5661	0.545	0.5661
13	8.747	8.469	1.061	1.097	1.061	1.097
14	10.20	9.88	1.235	1.277	1.235	1.277
15	3.888	3.764	0.538	0.5537	0.538	0.5537
16	22.43	23.81	3.750	3.838	3.450	3.531
TOTAL	368.2	359.9	43.8	45.3	37.00	38.23

[1]After subtracting on-site generation in subsectors 3, 4, 7 and 16.

Having checked the numerical validity of the NRDC projections of future energy requirements in the manufacturing sector, it is now possible to compare and contrast it with the results of the BPA projections in this sector to 1985 and 1995. In this comparison only the central station electricity requirements of the subsectors are considered, since it is this requirement that fundamentally impacts BPA. Table 2.4-5 shows the subsector aggregations in the same format as given in the SOM Study (Reference 4) along with the respective subsector electricity requirements in 1975, 1985 and 1995. It is important to re-emphasize that the Power Plant Scenario is a business-as-usual scenario, while the Alternative Scenario is predicated on effects of employment mix changes, conservation programs, etc.

TABLE 2.4-5

PNW MANUFACTURING SECTOR
CENTRAL STATION ELECTRICAL ENERGY REQUIREMENTS
(10^9 kWh per year)

Alternate Scenario Subsector #	Industry	1975[1] (BPA/SOM)	1975[2] (Alternative Scenario)	1985[3] (BPA/SOM)	1985[4] (Alternative Scenario)	1995[5] (BPA/SOM)	1995[4] (Alternative Scenario)
1	Food & Kindred Products	1.33	1.48	1.85	2.34	2.80	2.89
3	Lumber & Wood Products	3.80	3.68	5.10	3.84	6.84	2.77
4	Paper & Allied Products	2.72	2.62	3.48	3.41	4.32	3.54
6	Chemicals & Allied Products	3.21	4.78	4.68	6.42	7.10	6.90
9	Iron & Steel (Ferrous)	0.72	1.21	0.86	1.76	1.00	1.95
10	Non-Ferrous, Non-Aluminum	1.72	2.19	1.83	2.87	1.90	3.05
11	Primary Aluminum	26.85	27.29	30.32	28.67	32.70	6.00
2, 5, 7, 8 12 through 16	Other Industrial	7.34	4.96	27.43	8.67	65.43	11.40
TOTAL		47.69	48.21	75.55	57.98	122.09	38.24

[1]Calculated from 1974 actual industrial electricity use data and projections of industrial electricity use to 1980 given in the SOM Study, p. 182 (Reference 4), and modified to exclude on-site generation existing in 1975 in subsectors 3, 4 and 7 to the extent of 10%, 60% and 10% of their respective total electrical energy requirements (Reference 4), p. 177).

[2]Alternative Scenario Report, Table 19, p. 69, given as central station electrical energy requirements, i.e., excluding on-site generation existing in 1975 in subsectors 3, 4 and 7 (Reference 3).

[3]Calculated from projections of total industrial electrical energy requirements for the PNW in 1980 and 1995 given in the SOM Study, p. 182 (Reference 4), and modified to exclude on-site generation in subsectors 3, 4, and 7 to the extent of 10%, 60% and 10% of their respective total electrical energy requirements (Reference 4, p. 177).

[4]Alternative Scenario Report, Table 19, p. 69, given as central station electrical energy requirements, i.e., excluding on-site generation in subsectors 3, 4, 7 and 16 (Reference 3).

[5]Modified from projections of total industrial electrical energy requirements for the PNW in 1995 given in the SOM Study, p. 182 (Reference 4) to exclude on-site generation in subsectors 3, 4 and 7 to the extent of 10%, 60% and 10% of their respective total electrical energy requirements (Reference 4, p. 177).

The most significant difference between the two projections in 1985 is in the subsector designated "other industrial." The ten-year growth rate of electrical energy demand in this subsector as projected by BPA is 14% per year compared to less than 6% per year by the Alternative Scenario. In 1985, this difference in growth rates accounts for nearly 94% of the difference in the total electricity requirements in the two projections for the entire sector. This difference, in the same subsector, is considerably greater in 1995, where BPA's projections of 65.4 x 10^9 kWh is almost six times as great as the 11.4 x 10^9 kWh given by the Alternative Scenario.

These differences are too large to be explained on the basis of a conservation versus no-conservation theme. The fundamental reason that underscores this wide disparity in the two estimates must therefore be in the different energy projection methodologies adopted by BPA and the Alternative Scenario. It appears that BPA's trend extrapolation overestimates the energy demand in this subsector for the following reasons. BPA has projected the total sector requirements to 1985 and 1995 based on past trends. From this, selected subsector projections for which adequate energy demand growth data was available were subtracted and the final difference from the total seems to have been ascribed to the "other industrial" category.[1] There appears to have been no independent validation of the actual consumption in this category. On the other hand, the Alternative Scenario's zero-based projection follows a rather unorthodox procedure, particularly with regard to the impact of employment mix changes on energy demand. This may possibly underestimate the requirements due to consideration of surrogate labor multipliers rather than forecasted output to estimate future energy demand.

As part of this evaluation, a scenario for the manufacturing sector was developed following the above described reconstruction procedure of the Alternative Scenario, but in which energy conservation was excluded and

[1]BPA personnel verbally indicated (Reference 16) that the "other industrial" category includes unaccounted-for residues from the other sectors as well. Since no documentation of this was available, it was assumed this category applied strictly to the manufacturing sector.

TABLE 2.4-6
MANUFACTURING SECTOR CENTRAL STATION
ELECTRICAL ENERGY REQUIREMENTS
(10^9 kWh)

YEAR	POWER PLANT SCENARIO	ALTERNATIVE SCENARIO IMPLICIT BASELINE PROJECTION[1]	ALTERNATIVE SCENARIO
1985	75.6	60.7	58.0
1995	122.1	70.0	38.2 With Phasedown of Aluminum Industry
			64.9 Without Phasedown of Aluminum Industry

[1]Determined in this study.

the Alternative Scenario employment ratios in 1985 and 1995 were replaced with the corresponding BPA employment ratios. All substitution effects were left unchanged. The results of this calculation are shown in Table 2.4-6 and amply demonstrate that had the Alternative Scenario included an implicit baseline electrical energy projection, it would have shown considerably lower energy demands relative to BPA's in both years.

This determination has important implications with respect to the electrical energy demand differences stated in the Alternative Scenario in this sector relative to BPA projections, i.e., 17.6 x 10^9 kWh in 1985 and 83.9 x 10^9 kWh in 1995 (see Table 2.4-5). Considered from the hypothetical although logical baseline projection rather than from BPA's, the 1985 and 1995 demand reductions possible in the Alternative Scenario are much smaller, i.e., 2.7 x 10^9 kWh in 1985 and 31.8 x 10^9 kWh in 1995 (see Table 2.4-6). Furthermore, if none of the aluminum plants were retired by 1995, the baseline projection would not be 38.2 x 10^9 kWh but rather 64.9 kWh, the difference arising from the electrical energy demands of those plants that were eliminated in the Alternative Scenario (see Table 2.4-6).

The Alternative Scenario does consider the possibility of retaining all the aluminum plants, in view of the 4000 MW surplus generating capacity that is available in 1995 in their scenario. However, the allocation of this surplus capacity to the aluminum subsector effectively removes the margin of reserve that this capacity would have provided in case the Alternative Scenario implementation levels of energy conservation measures were not achieved. The resolution of this problem has not really been addressed.

2.4.1 Summary of Manufacturing Sector Description

The analysis of the manufacturing sector has presented a very interesting and important aspect of energy conservation studies in that it has shown the need for very careful and consistent projections of future energy requirements before judgments of conservation potential can be drawn. In the dramatic effect created by the "other industrial" category projections of BPA and the Alternative Scenario, the differences in energy demand between the other subsectors seem small by comparison. However, these small differences are significant, but in-depth analysis of them is possible only with much more detailed data than has been provided by BPA.

Figure 2.4-1 displays the projected electricity requirements for this sector as specified in the two scenarios, and also shows the calculated Alternative Scenario's projection with no employment mix changes and without implementation of conservation.

In summary, the following points in the analysis need to be emphasized:

1. The Alternative Scenario for 1985 was successfully reconstructed following the assumptions given in their study.

2. The procedure followed in the Alternative Scenario for energy demand projections is rather unorthodox. Employment mix changes were postulated to achieve an overall less energy intensive industrial base, evidently without verification of viability and social impact of these changes (these issues are addressed in Section 4.0 of this report). Additionally, across-the-board energy efficiency improvements were assumed for all subsectors without specific analysis.

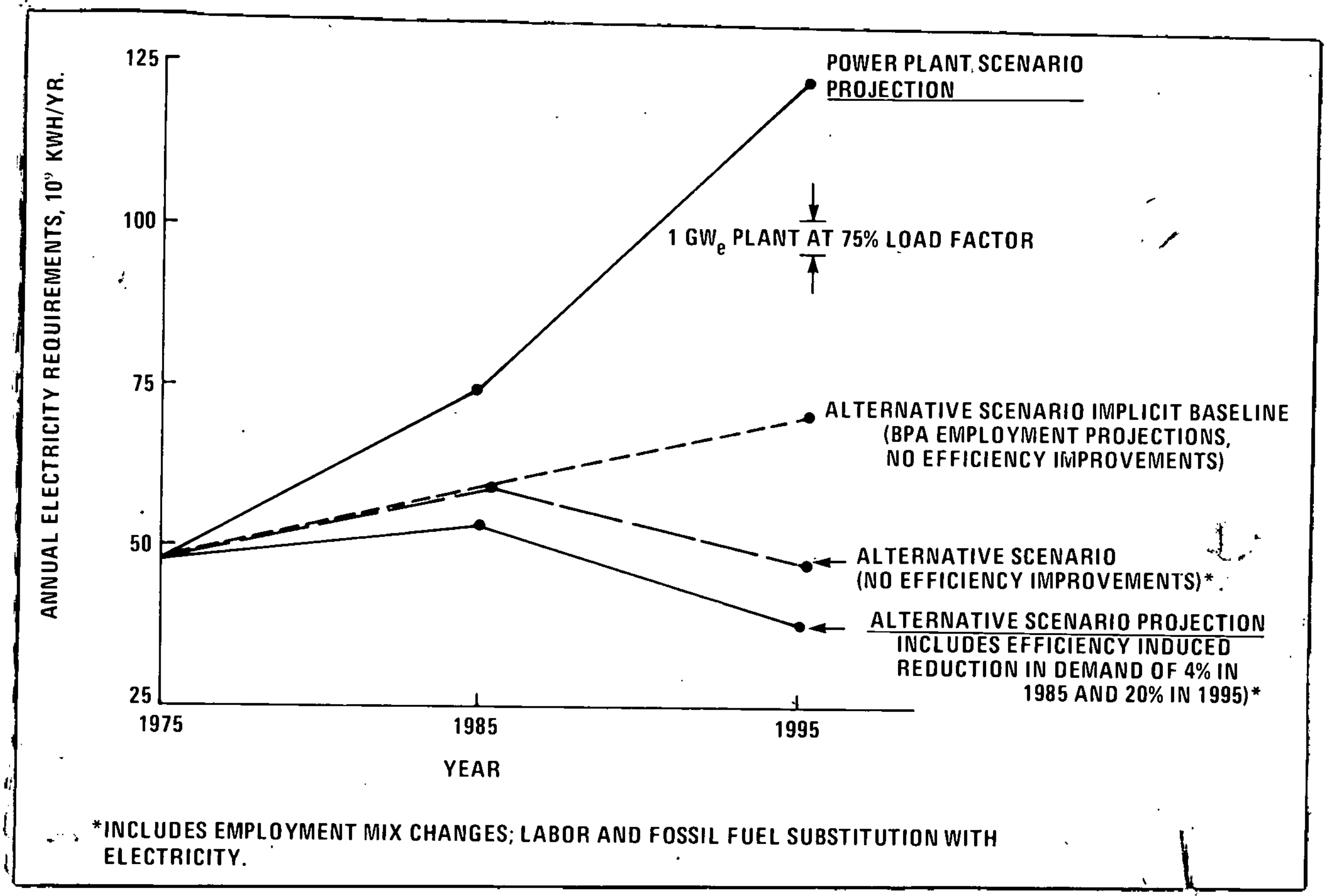


FIGURE 2.4-1 COMPARISON OF ELECTRICAL ENERGY CONSUMPTION FORECASTS FOR THE MANUFACTURING SECTOR OF THE PNW, 1975-1995

3. The implicit before conservation projections to 1985 and 1995 for the Alternative Scenario significantly differ from the projections given by BPA.

4. The conservation potential in this sector relative to BPA projections as specified in the Alternative Scenario is high. This is not by virtue of implementing conservation programs, but rather because of a much lower rate of growth in energy demand even prior to conservation compared to BPA's growth rate.

3.0 ECONOMIC ANALYSIS

3.1 INTRODUCTION

The specific problem addressed in this portion of the study is whether the total cost to the consumers in the PNW region for their end-use energy services, e.g., residential space heating, will be less for the Alternative Scenario than the Power Plant Scenario. The contrast is primarily between the two scenarios considered independently. However, a few comparisons will also be made between the before and after conservation implementation within the Alternative Scenario.

The economic assessment is conducted entirely from the consumer's point of view in both scenarios. The cost of meeting electricity demand in the Power Plant Scenario in terms of capital expenditures for power plants, fuel costs, and operation and maintenance costs as compared to that in the Alternative Scenario is captured implicitly in the difference between the (blended) prices of electricity as delivered to consumers in the two scenarios. Costs for implementing conservation measures are incurred only in the Alternative Scenario. Since the period of interest is limited to the 20 years between 1976 and 1995, the capital costs for new power plants (which typically have a 30-35 year economic lifetime) and some of the capital costs for conservation measures will not be fully amortized within this time period. The effect of this "overflow" of the cost stream beyond the temporal boundaries of this study will be discussed in Section 3.2.4.

The economic trade-off between the two scenarios for the PNW can be stated simply as that between two options that consumers have for the 20-year period from 1976 to 1995:

a. Invest in conservation measures that would reduce the rate of growth in electricity demand, decrease the need for additional power plant construction and consequently result in lower utility bills, both by virtue of the lowered demand and lower unit electricity prices.

b. Not invest in conservation measures and allow utility bills to rise with the unit price of electricity resulting from increasing additions of high-cost thermal power plants to meet the higher rate of demand.

The question addressed here is which of these two options is less expensive for the consumers over the next 20 years.

It is assumed in this study that the costs of specific conservation options (which are defined for the most part by the SOM Mandatory Strategy #6, Reference 4) are fully borne by the consumer (homeowner, etc.) installing the options. It is assumed they are financed over a five-year period at a 7% real (i.e., excluding inflation) interest rate.[1] The effect of incentives (tax rebates) included in the President's National Energy Plan are considered in Section 5.0.

While this economic trade-off is posed in a general fashion and therefore could be applied to any region in the United States, there are features specific to the PNW region. In particular, the hydro-electric capacity of the region, which presently accounts for approximately 80% of the electrical generation, is approaching saturation and most future baseload electrical capacity built there will be in the form of nuclear and coal-fired thermal power plants. Since the unit cost of new thermal capacity is much greater than the present unit cost of hydroelectric capacity, the region will experience a sharp and steady rise in the price of electricity if the Power Plant Scenario is followed. Conversely, by reducing the need for new thermal generation in the Alternative Scenario, the increase in electricity prices can be substantially reduced.

The lower electricity bills in the Alternative Scenario, as mentioned previously, would be due to two causes: 1) lower unit prices of electricity in terms of cents per kilowatt-hour delivered throughout the entire 20-year period; and 2) lower actual consumption of electricity. These two causes combine to produce a much lower cost for actual energy consumed than is the case in the Power Plant Scenario. However, this lower cost for energy is only obtained through a cost expenditure for conservation equipment. Whether the total cost to PNW consumers for their end-use energy services (energy cost plus capital and operating costs) will be lower or higher than the cost they would incur in the Power Plant Scenario is the trade-off addressed in this analysis.

[1]Lower than commercial rates may be available to some of the population (e.g., through state subsidized low interest loans for solar technologies and conservation measures). A limited number of parametric excursions were included in the study to consider lower interest rates and longer financing periods.

The economic comparison of these two scenarios was conducted for the residential and commercial sectors. Specific efficiency improvements in the manufacturing sector are not identified in the Alternative Scenario and thus could not be individually costed. The most significant impact of the manufacturing sector employment mix changes assumed by the Alternative Scenario fell under the category of institutional problems and is considered in Section 4.0. Similarly, since the difference between the two scenarios in energy requirements for the agricultural sector was relatively insignificant, the economic impact of these savings was not considered.

The following discussion of the economic methodology employed to evaluate the economic viability of the Alternative Scenario consists of: a discussion of the general formulation of the analytic approach; a description of the computation of blended electricity prices for the two scenarios (Section 3.3); a presentation of the costs of implementation of conservation initiatives employed in the economic analysis (Section 3.4); a detailed description of the residential sector analysis (Section 3.5); and a detailed description of the commercial sector analysis (Section 3.6).

3.2 GENERAL FORMULATION OF THE ANALYTIC APPROACH

The analytic approach quantifies the actual cost streams incurred by end-use consumers for their energy services in each of the two scenarios for the 20-year period. The present values of the cost streams are then computed and compared in order to determine which cost stream is the most economical from the consumer's viewpoint.

The present value of the costs for energy services in the Alternative Scenario is given by:

$$\text{Present Value of Cost} = \sum_{j=1}^{n} \sum_{t=1976}^{1995} \frac{P(t) \cdot E_j(t) + K_j(t) + M_j(t) + R_j(t)}{(1+i)^{(t-1975)}}$$

where j = End-use electricity consumer type j (e.g., single-family house built prior to 1976).

$P(t)$ = Price of electricity to the consumer at time t in the Alternative Scenario.

$E_j(t)$ = Electricity consumption during time t for all consumers of type j in the region.

$K_j(t)$ = The sum of the amortized capital cost for all conservation technology in time t for all consumers of type j in the region.

$M_j(t)$ = Annual maintenance costs for conservation technology in time t for all consumers of type j.

$R_j(t)$ = The sum of the amortized capital costs for replacement of any conservation technology in time t for consumer j (if any occurs from t = 1976 through 1995).

t = Calendar year of scenario.

i = Real social discount rate, assumed to be 4.5%/year.

n = Number of types of electrical consumers j.

In a similar manner, the present value of the cost stream to consumers in the Power Plant Scenario is represented as follows:

The present value of the costs for energy services in the Power Plant Scenario is given by:

$$\text{Present Value of Cost} = \sum_{j=1}^{n} \sum_{t=1976}^{1995} \frac{P'(t) \cdot E'_j(t) + K'_j(t) + M'_j(t) + R'_j(t)}{(1+i)^{(t-1975)}}$$

where j = End-use electricity consumer type j.

$P'(t)$ = Price of electricity to the consumer at time t in the Power Plant Scenario.

$E'_j(t)$ = Electricity consumption during time t for all consumers of type j in the region (i.e., consumption without conservation).

$K'_j(t)$ = The sum of the amortized capital cost for the conventional alternatives to a conservation technology (which may be zero as in the case of the alternative to insulation) in time t for all consumers of type j in the region.

$M'_j(t)$ = Annual maintenance cost for conventional technology in time t for all consumers of type j in the region.

$R'_j(t)$ = The sum of the amortized capital costs for replacement of any of the conventional technology in time t for all consumers of type j in the region.

t, i, n = As defined previously.

While this is the general analytic approach followed, a time-saving minor transformation is made which is mathematically equivalent. Specifically, wherever the capital costs $K_j(t)$, $K_j^{*}(t)$, maintenance costs $M_j(t)$, $M_j^{*}(t)$, and replacement costs $R_j(t)$, $R_j^{*}(t)$ are identical in the two scenarios, they are not included in either. Furthermore, whenever there is a choice to a consumer between purchasing a conservation technology $K_{j1}(t)$ and a conventional technology $K_{j1}^{*}(t)$ alternative to it, only the difference $(K_{j1}(t) - K_{j1}^{*}(t))$ in capital costs will be included in the Alternative Scenario side of the equation. This is mathematically equivalent to the original formulation since:

$$\sum_{\Delta t = 1}^{m} \frac{K_j(t)}{(1+i)^{\Delta t}} - \sum_{\Delta t = 1}^{m} \frac{K_j^{*}(t)}{(1+i)^{\Delta t}} = \sum_{\Delta t = 1}^{m} \frac{K_j(t) - K_j^{*}(t)}{(1+i)^{\Delta t}}$$

This latter difference $K_j(t) - K_j^{*}(t)$ will be called the incremental capital cost for conservation technology (generally a positive number), and is treated as if it were the total capital expenditure for the conservation technology. For example, if the installed cost of an electric heat pump system is \$2200 and the installed cost of a conventional electric resistence heating plus air conditioning system is \$2000, then the capital cost increment of the heat pump system is counted as \$200. However, in the case of a retrofit installation of a heat pump the full \$2200 must be charged to the Alternative Scenario. Similar procedures apply to the case of maintenance and replacement costs.

3.2.1 Specific Analytic Methodology with Reference to the Conservation Measures Proposed in the Alternative Scenario

The analytic methodology is reformulated in this section in more detail according to the specific conservation measures proposed in the Alternative Scenario taking into account the minor mathematical transformation discussed above.

3.2.1.1 Present Value of the Costs of Implementing the Alternative Scenario

Only the residential and commercial sectors are considered as these are the only sectors for which cost data are available. The organization of the computation follows the Alternative Scenario report and hence is divided into the following end-use categories: Residential Space Heating-Passive Measures; Residential Space Heating-Active Measures; Residential Water Heating, Lighting, and Appliances; Commercial Sector-Passive Measures; and Commercial Sector-Active Measures. The results are then summed over the categories.

a) Residential Space Heating - Passive Measures (RSH-P)

$$PV(RSH\text{-}P) = \sum_{\Delta t = 1}^{20} \sum_{j=1}^{4} \frac{\Delta C_j(t) + P(t) \cdot E_j(t) + \Delta M_j(t) + \Delta R_j(t)}{(1+i)^{\Delta t}}$$

where

j = Type of residential dwelling unit ($j = 1$ for single-family existing; $j = 2$ for single-family new; $j = 3$ for multifamily existing; and $j = 4$ for multifamily new).

$\Delta C_j(t)$ = Total amortized capital cost differential in year t for all conservation measures in dwelling unit j throughout the PNW region.[1]

$P(t)$ = Price of electricity at time t in Alternative Scenario.

$E_j(t)$ = Electrical energy consumption by dwelling unit j in year t according to Alternative Scenario.

$\Delta M_j(t)$ = Total annual maintenance cost differential in time t in dwelling unit j.

$\Delta R_j(t)$ = Total amortized capital cost differential in year t for replacing any conservation measures in dwelling unit j.

t = Calendar year of the scenario.

$\Delta t = t - 1975$

i = Real social discount rate (4.5%/year)

b) Residential Space Heating - Active Measures[2] (RSH-A)

$$PV(RSH\text{-}A) = \sum_{\Delta t = 1}^{20} \sum_{k=1}^{3} \frac{\Delta C_k(t) - P(t) \cdot E_k(t) + F_k(t) + \Delta M_k(t) + \Delta R_k(t)}{(1+i)^{\Delta t}}$$

[1] Henceforth, "dwelling unit j" or consumer j represents all consumers of type j in the region.

[2] These measures are additive to the passive measures.

where

k = Type of space heating conservation measure ($k = 1$ for heat pumps; $k = 2$ for solar; $k = 3$ for total energy system).

$\Delta C_k(t)$ = Total amortized capital cost differential in year t for implementing conservation measure k in all dwelling units j.

In general $\Delta C_k(t) = \sum_{j=1}^{4} \Delta C_k^j(t)$, where j = type of dwelling unit ($j = 1$ single family existing; $j = 2$ single family - new; $j = 3$ multifamily-existing; and $j = 4$ multifamily - new).

$P(t)$ = Price of electricity at time t in Alternative Scenario.

$E_k(t)$ = Electricity savings in time t associated with each active conservation measure k.

$F_k(t)$ = Product of natural gas consumption at time t and gas price $P_g(t)$ only for conservation measure $k = 3$, i.e. $F_1(t) = F_2(t) = 0$.

$\Delta M_k(t)$ = Total annual maintenance cost differential in time t associated with measures k as opposed to their conventional alternatives.

$\Delta R_k(t)$ = Total amortized capital cost differential of replacing conservation measure k in time t during the period t = 1976 through t = 1995 (if the lifetime of the measure is exceeded during this time period.)

$\Delta t = t - 1975$.

i = Real social discount rate (4.5%/year).

c) Residential - Water, Heating, Lighting, and Appliances (RWH,L&A):

$$PV(RWH,L\&A) = \sum_{\Delta t = 1}^{20} \sum_{k=1}^{13} \frac{\Delta C_k(t) + P(t) \cdot E_k(t) + \Delta M_k(t) + \Delta R_k(t)}{(1 + i)^{\Delta t}}$$

where

k = Type of conservation measure (k = 1 for water heating; k = 2 for lighting; k = 3 to 12 for other appliances; and k= 13 for solar).

$\Delta C_k(t)$ = Total amortized capital cost differential in time t for conservation measure k in all dwelling units j.

$P(t)$ = Electricity price at time t

$E_k^E(t)$ = Electricity consumption in time t by appliance k, except for k = 13. For k = 13 it is the electricity savings in time t, i.e. $- E_{13}(t)$.

$\Delta M_k(t)$ = Total annual maintenance cost differential in time t associated with owning appliance k (Note there is no supplementary fuel cost associated with k=13, since the backup system is assumed to be a full-sized electric water heater whose electricity consumption has been taken into account in k=1).

$\Delta R_k(t)$ = Total amortized capital cost differential of replacing conservation measure k in time t during the period t = 1976 to 1985 and from 1986 to 1995, as opposed to its conventional alternative.

$t, \Delta t, 1$ = Same as in part (a).

d) Commercial Sector - Passive Measures (CS-PM)

$$PV(CS\text{-}PM) = \sum_{\Delta t = 1}^{20} \sum_{j=1}^{5} \frac{\Delta C_j(t) + P(t) \cdot E_j^k(t) + \Delta M_j(t) + \Delta R_j(t)}{(1+i)^{\Delta t}}$$

where

j = Building-type-related conservation package valid for building types j = 1 to 5.

$C_j(t)$ = Total amortized capital cost differential in year t for implementing conservation package j.

$P(t)$ = Price of fuel in year t.

$E_j(t)$ = Electrical energy consumed in year t in building type j.

$\Delta M_j(t)$ = Total annual maintenance cost differential in time t associated with conservation package j.

$\Delta R_j(t)$ = Total capital cost differential of replacing conservation package j during the period [illegible] t = 1976-1995.

$t, \Delta t, i$ = Same as in part (a).

e) Commercial Sector - Active Measures (CS-AM)

$$PV(CS\text{-}AM) = \sum_{\Delta t=1}^{20} \sum_{k=1}^{2} \frac{\Delta C_k(t) - P(t) \cdot E_k(t) + F_k + \Delta M_k(t)}{(1 + i)^{\Delta t}}$$

where

k = Type of active measure implemented in an "average" commercial building (not one of the five building prototypes); $k = 1$ for solar, $k = 2$ for TES.

$C_k(t)$ = Total amortized capital cost differential in year t for implementing active measure k.

$P(t)$ = Price of electricity in year t.

$E_k(t)$ = Electricity savings by active measure k in year t by all "average" commercial buildings in which measure k is implemented.

$F_k(t)$ = Fuel cost for active measure k in year t; $F_1(t) = 0$ and $F_2(t)$ = product of gas consumption in year t and gas price in year t by all average commercial buildings in which the measure is implemented.

$\Delta M_k(t)$ = Total annual maintenance cost differential in time t associated with measure k.

Note: No replacement costs were assumed for these active measures in the 20-year period of interest.

$t, \Delta t, i$ = Same as in part (a).

f) Present Value of Cost of Implementing Conservation in the Residential/Commercial Sectors

$$PV_{Total} = PV(RSH\text{-}P) + PV(RSH\text{-}A) + PV(RWH, L\&A) + PV(CS\text{-}PM) + PV(CS\text{-}AM)$$

g) Present Value of Cost of Implementing the Power Plant Scenario

$$PV_{Total} = \sum_{\Delta t=1}^{20} \sum_{j=1}^{n} \frac{P^{*}(t) \cdot E_j^{*}(t)}{(1+i)^{\Delta t}}$$

where

$P^{*}(t)$ = Price of electricity in the Power Plant Scenario in year t.

$E_j^{*}(t)$ = Electrical energy consumption in year t in dwelling type or building type j.

$t, \Delta t, i$ = Same as in part (a).

3.2.1.2 Summary Economic Measures Based on Analytic Methodology

Based on the analytic methodology presented above, several summary economic measures may be developed which make it possible to compare the cost-effectiveness of the two scenarios for the combined residential and commercial sectors for the PNW region as a whole, or individually by sector (i.e., residential and commercial), or to compare the cost-effectiveness of various conservation measures within the context of the Alternative Scenario itself. Four measures are discussed: a) the 20-year cost streams incurred in each scenario; b) the present value of the benefit of implementing one scenario over the other (but excluding the Manufacturing Sector); c) the average unit cost of conservation ¢/kWh_e (in the two sectors in the Alternative Scenario versus the average unit cost of electricity supplied in the Power Plant Scenario over the 20-year period (or by individual year and sector); and d) benefit-cost measure of various conservation technologies within the Alternative Scenario.

a) Comparison of Twenty-Year Cost Streams Incurred in the Two Scenarios

This initial comparison of the two scenarios is presented graphically in the form of curves of incurred costs versus time. These results incorporate the effects of amortization of new generating capacity through higher blended electricity prices and where appropriate, costs of conservation implementation or conventional alternatives to conservation.

b) Present Value of the Benefit of One Scenario Over the Other (Manufacturing Sector Excluded)

Benefit = PV Cost (Power Plant Scenario) - PV Cost (Alternative Scenario)

This is the final comparison of the cost-effectiveness of following one scenario versus the other (of course, an analogous comparison could be made between the individual sectors of the two scenarios).

c) Unit Costs of Conservation Versus Unit Costs of Electricity Supply in the Residential and Commercial Sectors

The unit costs of conservation are determined by summing the incremental capital cost, maintenance cost, and replacement cost expenditures specifically associated with conservation technology in all of the years of the Alternative Scenario and then dividing by the total electrical energy saved in all of the years. This is represented in general as follows:

$$\text{Conservation Unit Cost } (¢/\text{kWh}_e\text{saved}) = \frac{\sum_{t=1976}^{1995} (\Delta C(t) + \Delta R(t) + \Delta M(t))}{\sum_{t=1976}^{1995} \Delta \text{kWh}_e(t)}$$

The average unit cost of electricity supplied in the Power Plant Scenario is:

$$\text{Supply Unit Cost } (¢\text{kWh}_e\text{produced}) = \frac{\sum_{t=1976}^{1995} (P`(t) \cdot E`(t))}{\sum_{t=1976}^{1995} E`(t)}$$

where $P`(t)$ and $E`(t)$ are as previously defined.

The above formulations are applicable to individual sector comparisons as well.

This is another way of measuring the cost-effectiveness to the consumer in these sectors of the Alternative Scenario relative to the Power Plant Scenario.

d) Benefit-Cost Measure of Conservation Technology Within the Alternative Scenario in the Residential and Commercial Sectors

This is a measure of the benefit to the consumer of implementing various conservation technologies within the context of the Alternative Scenario. If the benefit is greater than the cost, it is usually expressed as a benefit-cost ratio. If not, it is expressed as a net cost (cost minus benefit) to the consumer. The benefit-cost ratio of a measure k in a residential dwelling, for example, is represented as:

$$(B/C)_j^k = \frac{\sum_{t=1976}^{1995} \Delta kWh_e(t)_k \cdot P(t)}{\sum_{t=1976}^{1995} \Delta C_k(t) + \Delta R_k(t) + \Delta M_k(t)}$$

where

j = Dwelling type

$\Delta kWh_e(t)$ = Electrical energy saved by conservation technology k in year t.

$P(t)$ = Price of electricity in year t in Alternative Scenario.

$\Delta C_k(t), \Delta R_k(t), \Delta M_k(t)$ = As defined previously for Alternative Scenario.

The net cost measure is the denominator minus the numerator in the above expression.

3.2.2 Scope and Limitations of Analytic Methodology

There are several observations to be made regarding the above methodology in order to place it in perspective. These observations affect particularly the interpretation of the summary economic measures developed in Subsection 3.2.1.2. The first observation regards the effect of the cost stream overflow beyond the 1995 time boundary on summary measures "a" and "b" of Subsection 3.2.1.2. The second observation regards a caveat concerning summary measure "c".

First the effect of the cost stream overflow derives from two different sources, a power plant capital cost stream and a conservation technology cost stream. Since the amortization period (typically 35 years in the PNW) for central station electric power plants is normally longer than the amortization period for capital investments in conservation technology, there will be a longer and probably larger cost overflow resulting from the power plants committed in this time period than from the conservation technology installed in this period. The effect of the former overflow in particular is a "built-in" cost to future electricity prices in the region that will not be accounted for within the scope of this methodology. Thus, when comparing the present value of the cost streams in the two scenarios, it should be remembered that more of the total costs associated with conservation technology are accounted for in that 20-year period than are the total costs associated with the power plants constructed during that period.

Secondly, the effect of the overflow of the conservation technology cost stream is best seen not in relation to the power plant cost stream but in relation to the conservation technology benefit stream. In particular, the conservation technology cost stream overflow for measures implemented up to 1995 is for a much shorter period of time, in the longest case nine years beyond 1995, than is the benefit stream overflow. For instance, a homeowner putting in insulation will pay the costs associated with that investment only for the duration of his loan, e.g., five years. However, the benefits from that investment will last practically the lifetime of the dwelling, perhaps 50 or 60 years. So, for example, a homeowner who installs insulation in 1990 will have paid the total costs for the investment by 1995 according to our methodology, but will have had less than a tenth of the total lifetime benefits associated with that measure accounted for in the same period of time. The result of this is that the unit cost measure for conservation expressed in cents per kWh_e saved is not a life-cycle unit cost in most instances, i.e., for those with lifetimes extending beyond 1995, rather it is a measure of the actual unit cost incurred in the 1976-1995 time period. Since this unit cost measure does not take into account the total benefits accruing from most conservation measures implemented in the Alternative Scenario, it is a very conservative measure of the unit costs of conservation. This fact should be noted when interpreting summary measure "c," particularly when comparing it with the price of electricity expressed in the same units.

An observation should also be made regarding the interpretation of the benefit-cost measure for conservation technology within the Alternative Scenario. The benefit for an individual conservation technology is the product of the annual energy savings and the price of electricity in each year. The price of electricity in each year is that determined for the Alternative Scenario as a whole based upon the assumption that all conservation measures recommended in the scenario are being implemented. Therefore, the benefits calculated for any individual conservation technology are calculated at the low price of electricity resulting from the totality of all conservation technologies being implemented. Consequently, the resulting benefits may not be as great as they would be if each measure were implemented sequentially and the benefits calculated at the price of electricity obtained to that stage of implementation of the full conservation program. Thus, the benefits are not the marginal values obtained with the implementation of a specific technology but rather the actual values for that scenario.

As a consequence, certain measures might have a lower benefit-cost ratio or may even result in a net cost, in the context of this scenario. A conclusion that may be drawn is that incentives may be required not merely to stimulate the initial implementation of a conservation program but also to sustain it throughout the entire duration of the implementation period.

3.3 BLENDED ELECTRICITY PRICES IN THE TWO SCENARIOS

As mentioned in the previous section, one of the principal differences between the Power Plant and the Alternative Scenarios arises due to the prices of electricity the PNW region would experience during the 20-year period 1976-1995 (and beyond). This difference in price occurs because the present mix of generating sources (20% thermal, 80% hydro) is only slightly changed through 1995 in the Alternative Scenario, whereas it changes to approximately 65% thermal by 1995 in the Power Plant Scenario. The large thermal component in the power plant mix gives rise to the higher electricity prices in that scenario since the marginal cost of adding new thermal capacity is much higher than the actual cost of present baseload hydroelectric capacity (which remains practically unchanged in the next 20 years).

Thus, it is important to be able to forecast how electricity prices will change based on the different blend of costs from the thermal and hydroelectric generating plants that occurs in the two scenarios. It is the purpose of this section to present the methodology and data for producing these forecasts of blended electricity prices, and then to compare the results for the two scenarios.

3.3.1 Economic Methodology for Computing Busbar Power Cost On A Single Plant Basis

The busbar power cost (cost at the plant busbar, i.e., prior to transmission and distribution) consists of capital cost, fuel cost, and annual operation and maintenance cost. Each component can be expressed as a unit cost in mills per kilowatt-hour which, when added together, result in a total unit cost at the busbar. The transmission, distribution, and any further general and administrative costs incurred in order to deliver the electric power to the final consumer must be added to that busbar cost in order to obtain the delivered price of electricity which the consumer actually pays.[1] As the busbar cost component of the electricity price is the component of the electricity price which will vary with a change in generation mix, it will be discussed in detail in this section according to its three components.

3.3.1.1 Annualized Capital Cost Component

All annual charges associated with a utility's construction and ownership of an electric power plant are known as "capital carrying charges." When divided by the number of kilowatt-hours of electricity (kWh_e) generated annually by the plant, the result is what is here called the capital cost

[1]All rate structure effects, whether seasonally differential, class discriminatory, block structured, will be ignored here, and only average prices considered. The principal users of lower cost, direct service, electricity are in the manufacturing sector which, as previously stated, could not be considered in this analysis.

component of the busbar cost. To this stage the calculation of this component may be represented as:

(1) Capital Cost Component $(\frac{\text{Mills}}{\text{kWh}_e}) = \frac{\text{Capital Carrying Charge}}{\text{Annual kWh}_e \text{ Generated}}$

Each of the terms in this quotient may be disaggregated as follows. The capital carrying charge is the product of the plant capital and a fixed charge rate (FCR) representing a fixed fraction of the total capital cost paid annually. Total capital cost of the plant, including interest and escalation during construction as well as principal, is expressed in constant 1976 dollars.

The number of kilowatt-hours generated annually is simply the number of hours per year the plant is operating and multiplied by the installed capacity (kW_e) of the plant. Expression (1) may therefore be rewritten as follows:

(2) Capital Cost Component = $\frac{\text{Total Capital Cost x FCR}}{\text{8760 x C.F. x kW}_e}$

where C.F., the capacity factor is the fraction[1] of the total number of hours in a year (8760) that the plant is operating. Alternatively, expressing the quotient of the total capital cost and the installed capacity as a unit capital cost ($\$/kW_e$), expression (2) may be rewritten as:

(3) Capital Cost Component = $\frac{\text{Unit Capital Cost } (\$/\text{kW}_e) \text{ x FCR}}{\text{8760 x C.F.}}$

At this point only the FCR requires further detailed explanation. Referring back to expressions (1) and (2), it can be seen that the fixed charge rate represents a simplified method of calculating the annual capital carrying charges. It includes the following factors:

[1]This fraction also has built into it any fractional reductions from installed capacity at which the plant operates.

- Cost of capital.
- Depreciation (retirement of principal).
- Income taxes (includes tax depreciation and investment tax credit).
- Property taxes.

The first two factors combine to produce the capital recovery factor. This factor represents the fraction of the total capital investment which must be paid annually in order to fully amortize the investment over the specified time period, i.e., the depreciation period. For publicly-owned plants, the capital recovery factor is the only factor on which the fixed charge rate is based since these plants are generally exempt from property and income taxes. A further difference between publicly-owned and privately-owned plants occurs within the capital recovery factor itself since the cost of capital in the two cases is different. In particular, for a completely publicly-owned plant there is no equity involved, and hence, no return on equity is built into the cost of capital. Furthermore, the debt is usually financed with low interest, tax exempt bonds. The net result is a much lower cost of capital, and hence capital recovery factor, in the case of a publicly-owned plant.

Given this significant difference between the fixed charge rates for publicly and privately-owned plants--and in some cases joint ownerships--it was important to know both what the different rates were and what rates applied to which plants. Rather than attempting to calculate these rates based on average assumptions about all of these factors, and since detailed data concerning these factors were not available on a plant-by-plant basis, average rates were obtained directly from the PNW area utilities. Specifically, BPA and the Washington Public Power System were contacted, and based on the information provided by them, fixed charge rates of 13.5% and 8% were obtained as the appropriate rates for private and public utilities, respectively. Based on the split between private and public ownership of the plants, fixed charge rates were assigned or computed for each of the plants operated or planned by the PNUCC. These data are presented in Table 3.3-1.

TABLE 3.3-1

FIXED CHARGE RATES FOR PNW PLANTS

Plant Name	Public %	Private %	Average FCR
Nuclear			
Hanford	100%	-	0.08
Trojan	30%	70%	0.119
WNP 2	100%	-	0.08
WNP 4	100%	-	0.08
WNP 1	100%	-	0.08
WNP 3	70%	30%	0.097
Skagit 1	-	100%	0.135
Skagit 2	-	100%	0.135
Pebble Springs 1	15%	85%	0.127
Pebble Springs 2	15%	85%	0.127
WNP 5	90%	10%	0.086
Coal			
Centralia 1&2	28%	72%	0.120
Jim Bridger 2&3	-	100%	0.135
Colstrip 1&2	-	100%	0.135
Boardman	10%	90%	0.130
Jim Bridger 4	-	100%	0.135
Colstrip 3&4	-	100%	0.135

Note: The table shows only plants for which names and locations have been specified. Estimates were also made for the future plants designated by PNUCC by letter designations A through L.

With these rates and the unit capital costs and capacity factors for each plant (to be discussed in subsection 3.3.2), the capital cost component of the busbar cost could be calculated according to expression (3), and the results expressed in mills (thousandth's of 1976 dollars) per kilowatt hour.

3.3.1.2 Fuel Cost and O&M Cost Component of Busbar Cost

The unit fuel cost component of the busbar cost is obtained by dividing the cost of the fuel to the utility expressed in the appropriate units by the conversion efficiency of the plant (or, alternatively, by multiplying the cost by the heat rate of the plant). This is represented as the fuel cost component of busbar:

$$\text{Fuel cost (mills/kWh}_e) = \frac{\text{F.O.B. Fuel Cost (\$/MMBtu)}}{\eta \times 293} \times 1000$$

where

F.O.B. Fuel Cost = Delivered cost to the utility in $ per MMBtu.

η = Electric conversion efficiency

293 = Number of kilowatt-hours per MMBtu.

The operating and maintenance (O&M) cost component of the busbar cost is simply the annual O&M cost divided by the number of kilowatt-hours generated, and is usually supplied as an attribute of the plant in question expressed in mills per kilowatt-hour.

3.3.1.3 Total Busbar Power Cost

The total busbar power cost for a given power plant in a given year is simply the sum of the three components given above. It can be represented as:

Total Busbar Cost (mills per kWh_e) =

Capital Cost Component (mills per kWh_e) +

Fuel Cost Component (mills per kWh_e) +

O&M Cost Component (mills per kWh_e).

When the transmission and distribution costs to deliver this busbar power to a particular consumer are added to this cost, a reasonable proxy to the delivered price of electricity may be obtained.

3.3.2 Economic Input Data by Power Plant Type

Four basic power plant types were considered for purposes of computing busbar power costs: nuclear, coal-fired, hydroelectric, and miscellaneous thermal (e.g., small thermal plants, combustion turbines, etc.). For each of these plant types except hydroelectric, all the economic input data described in the previous subsection must be available to compute busbar costs.

Unit capital costs for nuclear plants were based on costs projected for the WPPSS #1-#3 plants and an assumed 1% real annual escalation rate from 1976. Unit capital costs for coal plants in 1976 were taken from the Northwest Energy Policy Project and escalated at a real rate of 1% per year for plants coming on line thereafter. Capacity factors for both types of plants were based on projected operating data published by the PNUCC (Reference 11) and shown in Table 3.3-2. Unit 1976 delivered costs of coal ($1.10/MMBtu) were based on data in the 1977 ERDA "Market-Oriented Program Planning Study" for coal delivered to the west north central region. The unit cost for nuclear fuel was assumed to be $0.549/MMBtu. For both fuels a 1% per year real escalation in costs was assumed. The unit fuel cost for miscellaneous thermal in 1976 was $2.38/MMBtu (assuming an initial 50-50 split between natural gas and distillate fuel in combustion turbines at prices of $1.75 and $3.00 per MMBtu respectively; the mix was changed to 100% distillate by 1995). Conversion efficiencies were 0.32 for nuclear, 0.36 increasing to 0.38 in 1995 for coal and 0.31 for miscellaneous thermal (Reference 102). O&M unit costs (mills/kWh_e) were 1.2 for nuclear plants, 2.6 for coal plants, and 3.0 for miscellaneous thermal, with no cost escalations (Reference 102).

3.3.3 Methodology for Computing Blended Costs and Electricity Prices

The methodology for computing blended prices of electricity in a given year consists of four steps: 1) average capital cost components of busbar cost by plant type; 2) average busbar costs by plant type; 3) blended busbar costs across plant types; and 4) blended electricity prices. Each of these steps is discussed in order.

3.3.3.1 Average Capital Cost Components of Busbar Cost by Plant Type

The first step of the procedure which eventually results in the blended price of electricity for the PNW region in a given year, is to compute the average capital cost component of the busbar for each plant type: nuclear, coal, and miscellaneous thermal. The miscellaneous thermal plant type has a constant capital cost component throughout the entire period since no new plants of this type are scheduled beyond 1978. The averaging process consists of weighting the capital cost component of the busbar cost by the actual power output of the plant in that year as a percent of the output for all plants of that type, that is, it is a megawatt-output weighted-average capital cost component.

Thus, the effect of a new plant of the same type that comes on-line in a given year is accounted for through the effect of its unit capital cost and capacity factor on the weighted average capital cost component of the busbar cost for that year. Having reached that point in the procedure it is only necessary to add the fuel and O&M costs--assumed to be the same for all plants of the same type in a given year--to the weighted average capital cost component in order to obtain the average busbar costs for those plants. This averaging process may be represented mathematically as follows:

The total average megawatt capacity for plants of type j is:

$$A_j(t) = \sum_{i=1}^{n} \alpha_i^j(t)$$

where

$A_j(t)$ = Total average megawatt capacity for all plants of type j in a given year t.

$\alpha_i^j(t)$ = Average megawatt capacity for plant i of type j (i.e., coal or nuclear) in year t.

n = Total number of plants of type j.

and, the capital cost component of the busbar cost for plant i is:

$$X_i^j = \frac{U_i^j(t) \cdot K}{C_i^j(t) \cdot 8760} \times 1000 \text{ in mills per kWh}_e$$

where

$U_i^j(t)$ = Unit capital cost for plant i of type j in $/kW$_e$ installed in year t.

K = Fixed charge rate factor.

$C_i^j(t)$ = Capacity factor for plant i of type j in year t.

The average capital cost component for all plants of type j is then obtained from:

$$\overline{X^j}(t) = \frac{\sum_{i=1}^{n} X_i^j(t) \cdot \alpha_i^j(t)}{A_j(t)}$$

where j = 1 for nuclear, j= 2 for coal, (and j = 3 for miscellaneous thermal).

3.3.3.2 Average Busbar Costs by Plant Type

To obtain the average busbar costs by plant type, the fuel and O&M components of the busbar cost must be added to the weighted average capital cost component. This operation is performed as follows: The fuel cost is expressed as:

$$\overline{y^j}(t) = y_0^j (1.01)^{t-1975}$$

where

Y_0^j = Price of fuel for plants of type j in 1975; j = 1 for nuclear fuel and j = 2 for coal (the price of oil and natural gas for miscellaneous thermal plants were forecasted independently).

t = Calendar year of generation.

1.01 = Base of exponent, representing a 1% per year escalation in the price of nuclear and coal fuels.

The operation and maintenance component is assumed to remain constant in constant dollars and is therefore

$$\overline{Z^j}(t) = Z^j \text{ in mills per } kWh_e.$$

Thus the total average busbar cost for any plant of type j in year t is (in mills per kWh_e):

$$\overline{B^j}(t) = \overline{X^j}(t) + \overline{Y^j}(t) + \overline{Z^j}(t)$$

3.3.3.3 <u>Blended Busbar Costs Across Plant Types</u>

Having obtained the average busbar costs for plants of each type j in the form of $\overline{B}_j(t)$, these costs must be averaged to obtain the overall blend for all plant types in the region in a given year. This is represented as:

$$\overline{B}(t) = \sum_j W_j \overline{B}_j(t)$$

where

$\overline{B}_j(t)$ = Weighted-averaged busbar costs for plants of type j.

$W_j(t)$ = Megawatt-output weight for plant types j expressed as a decimal fraction of the regional megawatt-output in year t.

Using the notation defined in the previous subsection, $W_j(t)$ can be represented explicitly as:

$$W_j(t) = \frac{A_j(t)}{\sum_j A_j(t)}$$

where

$A_j(t)$ = Total average megawatt-output from all plants of type j in the region in year t. Here j = 1 for nuclear, j = 2 for coal, j = 3 for miscellaneous thermal, and j = 4 for hydroelectric.

The difference between the two scenarios is then manifest in terms of both the number of plants of type j, in a given year, and (not independently) the weighted-average busbar cost $\overline{B_j}(t)$ in a given year, giving rise to a different $\overline{B}(t)$ for the two scenarios. Since the power plants accepted by the Alternative Scenario are a subset of those planned in the Power Plant Scenario, these scheduled capacity additions can be represented on one chart. Such a chart is shown in Table 3.3-2. The larger numbers in the body of

TABLE 3.3-2

PROJECTED PNW POWER RESOURCES MEGAWATTS DATA FROM REFERENCE 11

RESOURCES / YEAR	76-77	77-78	78-79	79-80	80-81	81-82	82-83	83-84	84-85	85-86	86-87	87-88	88-89	89-90	90-91	91-92	92-93	93-94	94-95	95-96
Hydroelectric	11,986	12,056	12,094	12,139	12,119	12,157	12,156	12,173	12,153	12,112	12,126	12,123	12,123	12,123	12,124	12,122	12,122	12,121	12,122	12,123
Potential Hydroelectric												57	114	171	228	285	342	399	456	516
Reserve Requirements	(334)	(346)	(356)	(369)	(387)	(361)	(397)	(404)	(416)	(436)	(462)	(484)	(510)	(553)	(567)	(603)	(641)	(680)	(718)	(755)
Hydroelectric Maintenance	(51)	(50)	(51)	(50)	(50)	(51)	(52)	(53)	(53)	(53)	(53)	(53)	(53)	(53)	(53)	(53)	(53)	(53)	(53)	(53)
Pumped Storage																	-50	-50	-50	-125
Nuclear Plants, PNUCC — Nuclear, Alternate Scenario:																				
Hanford-NPR	506[1] 506	167 167																		
Trojan	1130 529	1130 764	1130 847	1130 847	1130 847	1130 847	1130 847	1130 847	1130 847	1130 847	1130 847	1130 847	1130 847	1130 847	1130 847	1130 847	1130 847	1130 847	1130 847	1130 847
WNP 2				1100 550	1100 798	1100 825	1100 825	1100 825	1100 825	1100 825	1100 825	1100 .825	1100 825	1100 825	1100 825	1100 825	1100 825	1100 825	1100 825	1100 825
WNP 4								1250 562	1250 891	1250 938	1250 938	1250 938	1250 938	1250 938	1250 938	1250 938	1250 938	1250 938	1250 938	1250 938
WNP 1							1250 562	1250 891	1250 938	1250 938	1250 938	1250 938	1250 938	1250 938	1250 938	1250 938	1250 938	1250 938	1250 938	1250 938
Total Alt. Scenario Nuclear Average Capacity Factor	1636 1035 .632	1297 931 .718	1130 847 .75	2230 1397 .626	2230 1645 .738	2230 1672 .750	3480 2234 .642	4730 3125 .661	4730 3501 .740	4730 3548 .750	4730 3548 .750	4730 3548 .750	4730 3548 .750	4730 3548 .750	4730 3548 .750	4730 3548 .750	4730 3548 .750	4730 3548 .750	4730 3548 .750	4730 3548 .750
WNP 3								1240 620	1240 899	1240 930	1240 930	1240 930	1240 930	1240 930	1240 930	1240 930	1240 930	1240 930	1240 930	1240 930
Skagit 1 and 2								1288 708	1288 950	1288 966	2576 1674	2576 1916	2576 1932	2576 1932	2576 1932	2576 1932	2576 1932	2576 1932	2576 1932	2576 1932
Pebble Springs 1 and 2										1260 756	1260 945	1260 945	2520 1701	2520 1890	2520 1890	2520 1890	2520 1890	2520 1890	2520 1890	2520 1890
WNP 5										1240 806	1240 930	1240 930	1240 930	1240 930	1240 930	1240 930	1240 930	1240 930	1240 930	1240 930
Plant B[2]												1250 375	1250 844	1250 938	1250 938	1250 938	1250 938	1250 938	1250 938	1250 938
Plant D															1250 750	1250 938	1250 938	1250 938	1250 938	1250 938
Plant F																1250 375	1250 844	1250 938	1250 938	1250 938
Plant H																		1250 750	1250 938	1250 938
Plant J																			1250 750	1250 938
Plant L																				1250 750
Total PNUCC Nuclear Resource Average Capacity Factor	1636 1035 .632	1297 931 .718	1130 847 .75	2230 1397 .626	2230 1645 .738	2230 1672 .750	3480 2234 .642	7258 4453 .614	7258 5350 .771	9758 7006 .718	11046 8027 .727	12296 8644 .703	13556 9885 .729	13556 10,168 .750	14806 10,918 .737	16056 11,481 .715	16056 11,950 .744	17306 12,794 .739	18556 13,732 .740	19806 14,670 .741
Coal-Fired Plants, PNUCC — Coal, Alternate Scenario:																				
Centralia 1 and 2	1300 910	1300 910	1300 910	1300 910	1300 910	1300 910	1300 910	1300 910	1300 910	1300 910	1300 910	1300 910	1300 910	1300 910	1300 910	1300 910	1300 910	1300 910	1300 910	1300 910
Jim Bridger 2 and 3	1000 488	1000 631	1000 664	1000 664	1000 677	1000 724	1000 698	1000 724	1000 698	1000 724	1000 719	1000 719	1000 719	1000 719	1000 719	1000 719	1000 719	1000 719	1000 719	1000 719
Colstrip 1 and 2	330 267	330 274	330 280	330 255	330 256	330 256	330 256	330 256	330 256	330 256	330 256	330 256	330 256	330 256	330 256	330 256	330 256	330 256	330 256	330 256
Boardman Coal					460 230	460 333	460 345	460 345	460 345	460 345	460 345	460 345	460 345	460 345	460 345	460 345	460 345	460 345	460 345	460 345
Total Alt. Scenario Coal-Fired Average Capacity Factor	2630 1665 .633	2630 1815 .690	2630 1854 .705	2630 1829 .695	3090 2073 .671	3090 2223 .719	3090 2209 .715	3090 2235 .723	3090 2209 .715	3090 2235 .723	3090 2230 .722	3090 2230 .722	3090 2230 .722	3090 2230 .722	3090 2230 .722	3090 2230 .722	3090 2230 .722	3090 2230 .722	3090 2230 .722	3090 2230 .722
Jim Bridger 4				334 157	334 239	334 239	334 239	334 239	334 239	334 239	334 239	334 239	334 239	334 239	334 239	334 239	334 239	334 239	334 239	334 239
Colstrip 3 and 4					980 307	980 668	980 747	980 759	980 759	980 759	980 759	980 759	980 759	980 759	980 759	980 759	980 759	980 759	980 759	980 759
Plant A												1250 750	1250 938	1250 938	1250 938	1250 938	1250 938	1250 938	1250 938	1250 938
Plant C														1250 750	1250 938	1250 938	1250 938	1250 938	1250 938	1250 938
Plant E															1250 375	1250 844	1250 938	1250 938	1250 938	1250 938
Plant G																	1250 750	1250 938	1250 938	1250 938
Plant I																		1250 375	1250 844	1250 938
Plant K																			1250 375	1250 844
Total PNUCC Coal-Fired Resource Average Capacity Factor	2630 1665 .633	2630 1815 .690	2630 1854 .705	2964 1986 .670	4404 2619 .595	4404 3130 .711	4404 3195 .725	4404 3233 .734	4404 3207 .728	4404 3233 .734	4404 3228 .733	5654 3978 .704	5654 4166 .737	6904 4916 .712	8154 5479 .672	8154 5948 .729	9404 6792 .722	10654 7355 .690	11904 8199 .689	11904 8762 .736
Small Thermal and Miscellaneous, Combustion Turbines (including adjustments)	262	284	284	284	283	283	283	283	283	283	283	138	138	138	138	138	138	138	138	138
Total Alt. Scenario Resources[3]	14,948	15,086	15,079	15,649	16,120	16,335	16,882	17,816	18,146	18,178	18,187	18,039	18,039	18,039	18,040	18,038	18,038	18,037	18,038	18,039
Total PNUCC Resources[3,4]	14,948	15,086	15,079	15,806	16,666	17,242	17,868	20,142	20,993	22,634	23,664	24,940	26,426	27,516	28,887	29,974	31,294	32,757	34,597	36,084

1. Denotes peak capacity.
2. Division of unspecified thermal power plants (Plants A-L) between nuclear and coal-fired generation assumed by TRW.
3. Includes hydro reserve and maintenance requirements.
4. Includes potential hydro, pumped storage charge to base load subtracted.

the table represent the average megawatts of output while the smaller numbers above them indicate installed capacity (or peak output) for each individual power plant from 1976-1995, and are grouped according to resource: hydro, nuclear, coal, and miscellaneous thermal. Note that the plants scheduled in the Alternative Scenario are indicated within the bracket of the Power Plant Scenario.

3.3.3.4 Comparison of Blended Electricity Prices in the Power Plant and Alternative Scenarios

To obtain the blended electricity price in any year for either of the two scenarios, a constant was added to the blended busbar costs for that year. This constant is the transmission and distribution cost that must be added to the busbar cost in order to obtain delivered electricity prices. Transmission and distribution costs are assumed to remain constant over time because, while the unit costs of transmission may decrease slightly due to more efficient transmission lines being built in the future, the unit costs of distribution are expected to increase. The predominant offsetting effect is difficult to predict; consequently, it was assumed the net result is no change in the combined unit transmission and distribution costs.

While these transmission and distribution (T&D) costs are assumed to remain constant, and indeed the same constant for both scenarios, there is nevertheless a large capital expenditure associated with the new T&D capacity (as is also the case with the power plants) that is required in the Power Plant Scenario but not in the Alternative Scenario. If the difference is taken between the net firm resources in the Power Plant Scenario and the Alternative Scenario in 1995 of 24,872 peak megawatts, and assuming roughly the national average of $\$250/kW_e$ for T&D capacity, approximately 6.2 billion dollars of additional expenditure associated with the Power Plant Scenario (not including the capital expenditure for power plants - a much greater amount) results. Thus while the unit T&D costs are the same for both scenarios, this should not be interpreted to mean that the actual (total) costs for T&D are the same.

This constant was obtained by subtracting the average busbar cost of 6.09 mills per kWh_e from the average delivered electricity price of the major utilities in the region of 16.2 mills per kWh_e for 1976 which yields a delta T&D cost of 10.11 mills per kWh_e, which was held constant in constant dollars for the entire 20-year period. This also has the effect of calibrating the 1976 computed price to the actual price.

The final delivered blended electricity prices which resulted from the complete procedure described in Subsection 3.3.3.1 are presented in Figure 3.3-1.

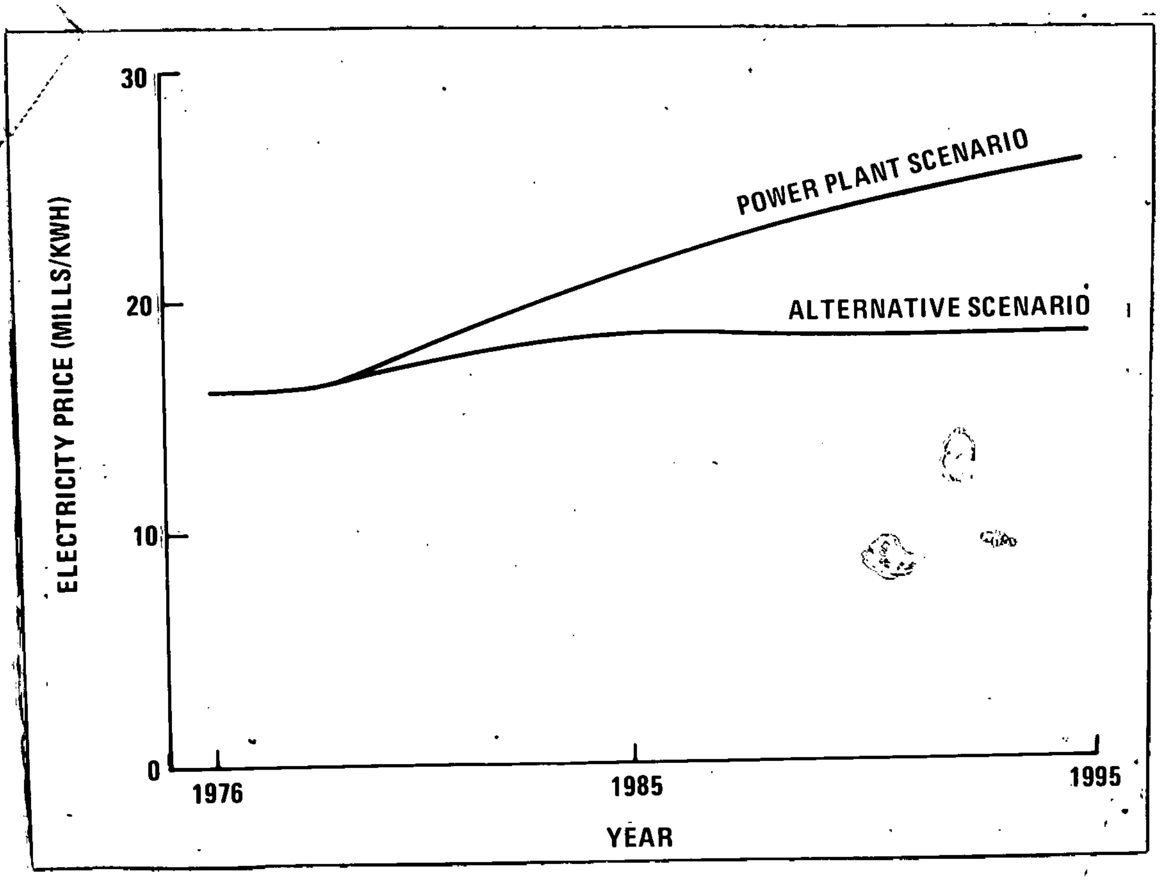


FIGURE 3.3-1. COMPARISON OF BLENDED ELECTRICITY PRICES IN THE POWER PLANT AND ALTERNATIVE SCENARIOS

3.4 CONSERVATION TECHNOLOGY COST DATA DOCUMENTATION

3.4.1 Introduction

The capital costs of individual passive energy conservation measures considered in the Alternative Scenario for the residential and commercial sectors were principally obtained from the SOM Study (Reference 4). Wherever possible, these capital costs were compared to costs for similar measures given in a Department of Commerce Study (Reference 5). This comparison showed significant variations in the costs for identical measures--not an unexpected result in view of the regional nature of the SOM analysis versus the national average scope of the Department of Commerce analysis. Due to the heavy reliance of the Alternative Scenario on the SOM conservation recommendations, which in turn were specific to the PNW region, and since each of the passive measures were costed by SOM in both sectors, the SOM costs for those measures were adopted for use in this study. Individual passive conservation measures by building type adopted in the Alternative Scenario for the residential and commercial sector are shown in Appendix A along with their capital costs as given in the SOM report (Reference 4).

In the case of active conservation measures, i.e., heat pumps, solar water heating and total energy systems which to a large extent were not considered in the SOM Study, costs were obtained from other sources in the open literature. This was true in the case of appliances as well, where, based on data obtained from several sources, estimates were made on incremental costs of improving appliance energy efficiencies. Appliance costs estimations are described herein. Costs for the active measures are discussed in Sections 3.5 and 3.6.

With some exceptions identified later, consumers in the residential sector were assumed to finance all energy conservation expenditures through five-year loans at a real interest rate of 7% (excluding inflation). Replacement costs of measures whose lifetime is less than 20 years and incremental maintenance costs associated with the active measures were considered wherever appropriate. In the commercial sector similar financing schemes were considered but with different loan periods and interest rates. These are discussed in Section 3.6.

3.4.2 Appliances

The percentage decrease in annual kWh requirements expected for each electric appliance (except lighting) by 1980 following efficiency improvements relative to 1975 was obtained from Department of Commerce data (Reference 5), and applied to respective 1975 appliance energy consumptions given in the Alternative Scenario. Independently, the incremental capital cost associated with each new and improved appliance was estimated from best available information. The ratio of incremental cost (Δc) to kWh savings ($\Delta\Sigma$) was computed for each appliance and was assumed to remain constant over the 20-year period 1976-1995. The incremental appliance cost in the Alternative Scenario in the years 1985 and 1995 was then obtained as the product of the $\Delta c/\Delta\Sigma$ ratio for each appliance and the respective energy savings specified in the Alternative Scenario in these years relative to 1975. The appliance costs in 1985 and 1995 are shown in Table 3.4-1 and related data in Table 3.4-2.

TABLE 3.4-1

PROJECTED IMPROVED EFFICIENCY APPLIANCE COSTS
(1976 Dollars)

Appliance	1975	1985	1995
Water Heater	120	155	167
Lighting	6-12	86/161[1]	96/174[1]
Refrigerator	490	717	721
Range	320	331	349
TV Color	390	446	446
TV B&W	160	187	187
Freezer	450	460	499
Dryer	200	210	210
Clothes Washer	285	285	285
Dishwasher	300	314	321
Air Conditioner	220	266	293

[1]Materials cost/installed cost.

TABLE 3.4-2

APPLIANCE COST/ENERGY CONSUMPTION RATIOS
(Costs in 1976 Dollars)

APPLIANCE	1975 Consumption[1] (kWh/yr.)	Percent Decrease in Electricity Consumption by 1980 (Reference 5)	Electricity Savings in 1980 Relative to 1975, ΔΣ (kWh/yr.)	1976 Base Cost[2]	Incremental Cost to Obtain 1980 Savings, Δc (1976$)	(Δc/ΔΣ) ($/kWh/yr.)	1985: Alternative Scenario 1985 Electricity Savings Relative to 1975 (kWh/yr.)	1985: Alternative Scenario Incremental Cost in 1985 (1976$)	1995: Alternative Scenario 1995 Electricity Savings Relative to 1975 (kWh/yr.)	1995: Alternative Scenario Incremental Cost in 1995 (1976$)
Water Heater	4442	9	400	120	20[3]	.05	700	35	932	47
Lighting	1662	30[3]	500	6-12	134/ 248[4]	.27/ .50	255	86/ 161	384	96/ 174
Refrigerator	672	-	-	490	-	-	-	227[3]	-	231[3]
Range	1108	10	111	320	20[3]	.18	62	11	161	29
TV Color (15"-17")	464	42	195	390	50[3]	.26	215	56	215	56
TV B&W (19")	334	48	160	160	25[3]	.16	167	27	167	27
Freezer	1103	25	276	450	100[3]	.36	27	10	137	49
Dryer	917	6	55	200	10[3]	.18	58	10	58	10
Clothes Washer	95	10	10	285	10[3]	1.00	0	0	0	0
Dishwasher	335	18	60	300	15[3]	.25	56	14	84	21
Air Conditioner	1008	22	222	220	40[3]	.18	257	46	408	73

[1]Alternative Scenario (Reference 3), Table 32, p. 159.
[2]See text for details.
[3]Estimated.
[4]Materials cost/installed cost.

3.4.3 Water Heater

A price ($120) for a water was chosen after reviewing the 1977 Consumers Reports Buying Guide (Reference 6) and the Sears Catalog (Reference 7). The range was from $117 to $189 for a 52-gallon electric water heater. Power consumption of each water heater is between 4500 and 5500 watts. The $120 price is representative of the "best buy" models.

It was assumed that the price of a 9% more efficient water heater would be $20. This should cover the cost of additional insulation and increasing the wall thickness to accommodate the extra insulation (total four to eight inches).

3.4.4 Lighting

The 1975 cost of lighting was taken as only the cost of the incandescent bulbs in a household. Assuming that a house has 15 to 20 light bulbs at a cost of 40 to 60 cents for each bulb, the total base cost in 1975 is $6 to $12. We have assumed that part of the lighting power requirements in 1985 and 1995 will be met with fluorescent lighting and that a 30% reduction in lighting related energy requirements could be met by 1980. It should be noted that the assumed 1980 reduction (30%) is large compared to the 1985 (15%) and 1995 (23%) reductions predicted by the Alternative Scenario.

It was assumed that each incandescent light bulb burns approximately one thousand hours per year and that each bulb is rated at 100 watts (probable high case). Accordingly, each bulb then contributes 100 kWh/yr to the lighting requirements.

White fluorescent lights give off 58 lumens per watt for a 40-watt four foot bulb. The 100-watt incandescent bulb gives 16 lumens per watt. On an equivalent lumen basis, a fluorescent bulb requires 3.625 (58 /16) times less energy than the incandescent bulb.

The reduction in energy required (kWh/yr) is the sum of the energy requirements of incandescent bulbs replaced less the energy required by the fluorescent bulbs which replace the incandescent bulbs. For example, in 1985 NRDC projects a 255 kWh/yr reduction in lighting requirements. Assuming that bulbs burn 1000 hours per year, the reduction in the wattage of incandescent bulbs, R_i to obtain this savings is calculated as follows:

$$R_i\ (1-1/3.625) = 255$$

$$R_i = 352$$

The 352 watts of incandescent bulbs will be replaced by 97 watts of fluorescent lighting.

Table 3.4-3 shows the cost of adding the fluorescent fixtures required by the energy reduction projections in the Alternative Scenario for 1985 and 1995. The cost of fixtures is included.

Table 3.4-3

FLUORESCENT LIGHTING REQUIREMENTS PER DWELLING UNIT AND COSTS[1]

Year	Energy Reduction from 1975 (%)	Energy Reduction from 1975 (kWh/yr)	Additional Fluorescent Lighting Required (watts)	Required Number of Fixtures 80 watt	Required Number of Fixtures 40 watt	Cost (76 dollars) Materials	Cost (76 dollars) Installed	Replacement Cost[2] Advantage (1976 dollars)
1985	15	255	97	1	1	86	161	2.00/year
1995	23	384	146	2	0	96	174	2.50/year

[1] "Building Construction Cost Data 1977," Robert Snow Means Co., Inc., 1976

[2] Reflects the savings arising from not having to replace four incandescent 100-watt bulbs each year for the period 1976-1985 and five incandescent 100-watt bulbs each year for the period 1986-1995. This assumes lifetime of incandescent bulbs is only 1 year as contrasted with an assumed lifetime of 10 years for the fluorescent bulbs (optimistic estimate).

3.4.5 Refrigerator

The Alternative Scenario shows a trend of increasing refrigerator kWh consumption per year. This is probably a result of energy conservation measures not fully offsetting the increased energy consumption arising from convenience measures such as automatic defrost and ice dispensers. The 1985 and 1995 prices are estimates.

3.4.6 Range

Ranges include an oven and four stovetop burners (usually three with a 6-inch diameter and one with an 8-inch diameter). The base cost ($370) was chosen after examining the 1977 Buying Guide Issue of Consumer Reports and the Sears catalog. Twenty dollars was estimated as the probable increased cost to meet the projected ten percent reduction in energy requirements by 1980.

3.4.7 Color TV

Costs for color televisions were taken from the 1977 Buying Guide Issue of Consumer Reports for 17-inch models. The majority of the energy used by a television is consumed by the picture tube. Advances in picture display techniques will account for the majority of the reduction in the energy requirements. The FEA projection is that a 42% reduction in energy consumption is possible for color televisions by 1980.

3.4.8 B&W Televisions

Costs were also taken from the 1977 Buying Guide Issue of Consumer Reports for 19-inch models.

3.4.9 Freezer

Freezer prices were determined for a 16-cubic foot upright freezer from the 1977 Buying Guide Issue of Consumer Reports and the Sears catalog. The cost of increasing the efficiency of the freezer (25% by 1980) was estimated to be approximately $100.

3.4.10 Dryer

The dryer price was taken from the 1977 Buying Guide Issue of Consumer Reports as a representative of the cost of a good household dryer. The cost of 6% increased efficiency by 1980 is estimated at $10 based on the cost of increased insulation and dryer design.

3.4.11 Clothes Washer

The price was taken from the 1977 Buying Guide Issue of Consumer Reports. The cost of the more efficient washer is an estimate. The major cost of using the washing is due to the cost incurred by using hot water. Manufacturers recommend cold water wash for many types of clothing and almost always recommend cold water rinse.

3.4.12 Dishwasher

The prices were obtained from sampling of the 1977 Buying Guide Issue of Consumer Reports and Sears catalog. The $15 increase for the 1980 models represents the cost of a switch which turns of the drying cycle.

3.4.13 Air Conditioner

The price was taken from the Sears catalog. The 1980 price increase is also from the Sears catalog (the high Energy Efficiency Ratio model). Room air conditioners with 5000 Btu/hr capacity were considered.

3.5 RESIDENTIAL SECTOR ANALYSIS DESCRIPTION

The economic analysis of the residential sector is the first part of the overall analysis constructed to determine the present value of the differences in total cost to the consumers over the time period 1976 to 1995, between the Alternative Scenario and the Power Plant Scenario.

Three major sets of energy conservation programs described in the Alternative Scenario report are addressed in this sector. These can be defined as follows:

a. Passive conservation programs for space conditioning encompassing additions of insulation, storm windows, weatherstripping, automatic thermostat night setback, etc. These are termed passive because their function is to reduce building heating and cooling loads rather than provide these services more efficiently.

b. Active conservation programs that result in replacement of conventional heating and cooling systems with new systems that provide the same level of service to the consumer with greater energy efficiency. Measures in this program comprise heat pumps and solar space heaters. Fuel cell total energy systems are also included in this category. These measures are considered in the Alternative Scenario as being additive to the passive measures.

Both the active and passive programs are evaluated only in the context of those homes (old and new) that have or would otherwise have had electric resistance heating (Alternative Scenario assumption).

c. Conservation programs that relate to the use of energy efficient lighting systems, electric water heaters and electric appliances in the residential sector and which also include consideration of solar water heaters as an alternative to the conventional electric water heater. These programs are not restricted to all electric homes.

The elements influencing the economic analysis will vary with the type of the conservation program addressed and type of residence in which the implementation is done, i.e., existing homes or new homes. The cost elements for an individual consumer may be broadly classified as follows:

Non-Energy Costs:

- Capital cost of conservation measures, particularly for the passive measures in a retrofit mode, or incremental capital cost of active measures in new homes where a choice exists between conventional and new measures as in the case of replacing electric resistance heating with solar heating, or replacing existing appliances with more efficient ones.
- Replacement cost of measures such as weatherstripping where the lifetime of the measure is less than the 20-year (1976-1995) time frame being considered.

- Incremental maintenance costs for equipment such as heat pumps and solar heating relative to conventional equipment.
- Cost of capital that is borrowed to purchase and implement the conservation measures.

<u>Energy Costs</u>:

- The unit price of electricity (mills/kWh) to the consumer in the Alternative Scenario is dictated by the mix of electric generation and associated systems given in the Alternative Scenario. (This has been discussed in Section 3.3.) Unit energy costs ($/MMBtu) for other fuels such as natural gas for fuel cells are computed herein for each year using data from other sources.
- Annual electric consumption by various residential consumers in the two scenarios.

Two other important elements of the analysis which are considered in this study are the rates of change between 1975 and 1995 of the stock of homes in which conservation measures are implemented and the rates of implementation of the measures themselves. These rates have been derived using pertinent data from the Alternative Scenario and will be discussed for each individual measure.

The economic analysis allows the determination of total costs to the consumers in the Alternative Scenario in constant 1976 dollars for each year from 1976 to 1995. This cost stream is then compared to a similar cost stream in the Power Plant Scenario. It is important to re-emphasize that the Power Plant cost stream is solely an energy cost stream, since capital cost effects in the Power Plant Scenario have been accounted for by considering incremental costs wherever appropriate in the Alternative Scenario.

3.5.1 Space Heating and Passive Conservation Measures

3.5.1.1 Single-Family Residences Built Prior to 1976 (SF<76)

The total number of single family homes existing in 1975 was 1.68 million. This stock of homes declines to 1.598 million by 1985 and 1.521 million by 1995. According to the Alternative Scenario, while the total stock of these homes declines, the fraction of these homes that are electrically heated (saturation) increases between 1975 and 1995 due to conversion from heating with fossil fuels to heating with electricity. The net results in an increasing stock of electrically heated homes. This trend is shown in Figure 3.5-1 and is linear. It can be expressed as:

$$H_1 = 3.78\times10^5+0.1\times10^5(t-1975) \quad 1976\le t<1995$$

YEAR	TOTAL NUMBER OF SINGLE FAMILY HOMES BUILT PRIOR TO 1976[1]	SATURATION[2]	TOTAL NUMBER ELECTRICALLY HEATED HOMES
1975	1.68×10^6	0.225	3.78×10^5
1985	1.598×10^6	0.300	4.79×10^5
1995	1.521×10^6	0.380	5.78×10^5

[1]Reference 3, Table 6, p. 33.
[2]Ibid, Table 29, p. 154.

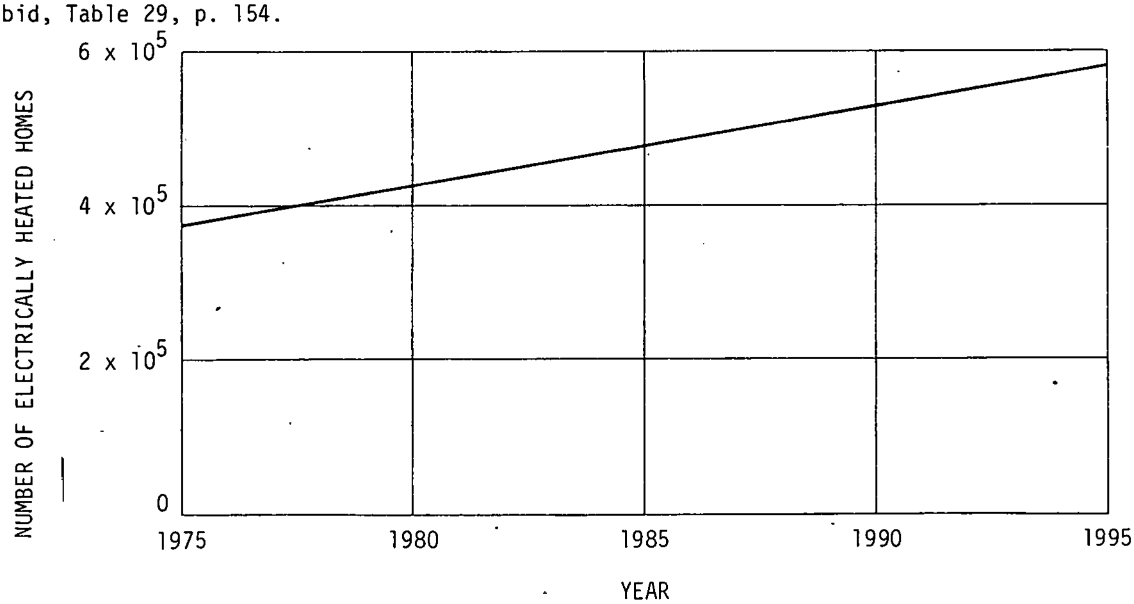


FIGURE 3.5-1. 1975-1995 TREND OF THE STOCK OF ELECTRICALLY HEATED SINGLE-FAMILY HOMES BUILT PRIOR TO 1976

The implementation level of passive conservation measures in these homes over the time period 1976 to 1995 is shown in Figure 3.5-2. The linearity of the trend is an Alternative Scenario assumption and the linear rate of implementation of each of the passive measures over the period 1976 to 1995 is given by:

- Insulation, I_1 = 4.55%/year
- Storm Windows, S_1 = 4.50%/year
- Weatherstripping, W_1 = 3.70%/year
- Automatic thermostat night set-back, N_1 = 3.70%/year

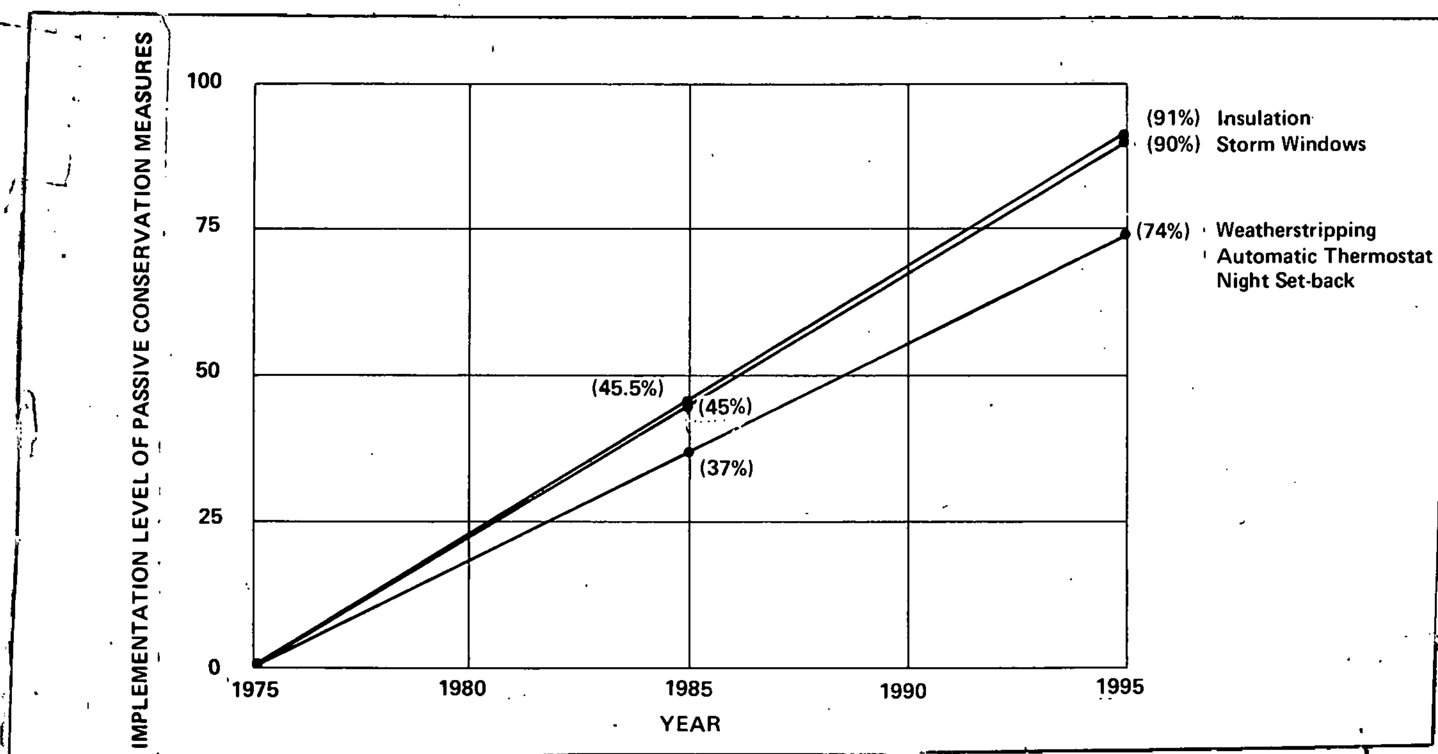


FIGURE 3.5-2. LEVEL OF IMPLEMENTATION OF PASSIVE CONSERVATION MEASURES IN SINGLE-FAMILY HOMES BUILT PRIOR TO 1976

From the stock of homes H_1 existing in each year and the corresponding conservation measure implementation level, the annual market penetration (i.e., number of units sold per year) of each measure can be determined. It is the difference in the number of units existing in a given year and the number existing in the previous year. These penetrations can be expressed by the following equations:

- Insulation, $I_1 = 910(t-1975)+16740$, $1976 \leq t \leq 1995$
- Storm Windows, $S_1 = 900(t-1975)+16560$, $1976 \leq t \leq 1995$
- Weatherstripping, $W_1 = 740(t-1975)+13620$, $1976 \leq t \leq 1980$
  $= 1480(t-1975)+23540$, $1981 \leq t \leq 1995$
- Night Set-back, $N_1 = 740(t-1975)+13620$, $1976 \leq t \leq 1995$

Weatherstripping is assumed to have a lifetime of only five years and therefore has to be replaced accordingly, a characteristic which is incorporated in the equation for weatherstripping.

The initial capital cost of these conservation measures was obtained from the SOM Study (Reference 4). These costs in 1976 dollars were assumed constant over the 20-year period and are tabulated below:

- Insulation = $726
- Storm Windows = $910
- Weatherstripping = $38
- Night Set-back = $65

Each consumer who implements the conservation measures of insulation, storm windows and automatic thermostat night-set-back is assumed to finance the cost through a five-year loan at a real interest rate of 7%. The costs for weatherstripping are assumed to be borne out-of-pocket.

The annual capital cost of implementation of the passive conservation programs in these homes in any given year is the sum of the product of the penetration of each measure and its annualized cost (i.e., after financing). The total capital cost outlay in a given year is then the sum of the costs associated with that year's implementation and the cost accruing from implementation in the previous years. Replacement costs for weatherstripping are factored in each year starting with 1981. This accounting procedure in constant 1976 dollars is truncated in 1995 since this year marks the end of the period of interest in the Alternative Scenario. The effect of this truncation on the results has been discussed in Section 3.2.2.

The total cost for space heating borne by all consumers in the Alternative Scenario owning electrically heated single-family homes built prior to 1976 in any year thereafter is determined by four factors:

a. Total capital and operating (maintenance plus replacement) cost outlay in a given year for homes in which one or more passive conservation measures have been implemented.

b. The year's consumption of electricity for space heating in homes with the conservation measures.

c. The year's consumption of electricity for space heating in homes with no conservation measures.

d. Unit price of electricity to the consumer in that year.

The procedure for determining the first factor has been described herein and the computation of the unit price of electricity has been shown in Section 3.3. The second and third factors which together give the total electricity requirements for space heating in these homes in any year were provided in the Alternative Scenario Report by specifying a weighted average annual thermal performance coefficient for space heating in these homes from 1975 to 1995. Consequently, it is possible to calculate the yearly total cost stream to 1995 for space heating in these single-family homes following implementation of the passive conservation measures. The results of this calculation are discussed later.

The procedure described above has been followed for analyzing the costs of space heating with passive conservation measures in the other three residential building types as well, i.e., single-family residences built after 1976 and multifamily dwellings built prior to and after 1976. The pertinent data for each of these building types are shown below.

3.5.1.2 Single-Family Residences Built After 1976 (SF>76)

The yearly stock of residences in this category with electric heat is given by:

$$H_2 = 0.274\times10^5(t-1975),\ 1976\leq t\leq 1985$$

$$= 2.74\times10^5+0.425\times10^5(t-1985),\ 1986\leq t\leq 1995$$

A linear rate of increase in the stock of these homes has been assumed both between 1976 and 1985 and between 1986 and 1995. The Alternative Scenario assumes a linear rate of implementation of each passive conservation measure in these homes over the period 1976 to 1995:

- Insulation I_2 = 4.9%/year
- Storm windows S_2 = 4.9%/year
- Automatic thermostat night set-back W_2 = 3.7%/year

Market Penetration

- Insulation $I_2 = 2685(t-1975)-1343, \quad 1976 \le t \le 1995$

  $= 4166(t-1975)-9486, \quad 1986 \le t \le 1995$
- Storm windows S_2 = same as for insulation
- Night set-back $N_2 = 2028(t-1975)-1014 \quad 1976 \le t \le 1995$

  $= 3146(t-1975)-7164 \quad 1986 \le t \le 1995$

Initial Capital Costs in 1976 Dollars (Reference)

- Insulation = \$539
- Storm windows = \$262
- Night set-back = \$65

Financing

- Bank loan for 5 years at a real interest rate of 7%.

Space Heating Efficiency

- Weighted average annual thermal performance coefficients from the Alternative Scenario.

3.5.1.3 Multifamily Dwellings Built Prior to 1976 (MF<76)

The yearly stock of residences in this category with electric heat is given by:

$$H_3 = 4.72 \times 10^5 - 0.018 \times 10^5 (t-1975), \quad 1976 \le t \le 1995$$

The linear rate of decline in the stock of these homes is an Alternative Scenario assumption. Unlike in the case of single-family homes built prior to 1976, the rate at which these homes decline is greater than that with which conversions from fossil fuel to electric heating take place. Consequently, the stock of these homes with electric heating declines with time. The Alternative Scenario assumes a linear rate of implementation of each passive conservation measure in these homes over the period 1976 to 1995:

- Insulation, I_3 = 4.3%/year
- Storm windows, S_3 = 4.2%/year
- Night set-back, N_3 = 3.45%/year
- Weatherstripping, W_3 = 3.45%/year

Market Penetration:

- Insulation, $I_3 = 20373-155(t-1975)$, $1976 \le t \le 1995$
- Storm windows, $S_3 = 19900-151(t-1975)$, $1976 \le t \le 1995$
- Night set-back, $N_3 = 16346-124(t-1975)$, $1976 \le t \le 1995$
- Weatherstripping, $W_3 = 16346-124(t-1975)$, $1976 \le t \le 1980$ (replaced every 5 years) $= 32712-248(t-1975)$, $1981 \le t \le 1995$

Initial Capital Costs in 1976 Dollars (Reference)

- Insulation = $180
- Storm windows = $338
- Night set-back = $65
- Weatherstripping = $18

Financing:

- Bank loan for 5 years at a real interest rate of 7%.

Space Heating Efficiency

- Weighted average annual thermal performance coefficients from the Alternative Scenario.

3.5.1.4 Multifamily Dwellings Built After 1976 (MF>76)

The yearly stock of residences in this category with electric heat is given by:

$$H_4 = 0.278 \times 10^5 (t-1975), \quad 1976 \le t \le 1985$$

$$= 2.78 \times 10^5 + 0.45 \times 10^5 (t-1985), \quad 1986 \le t \le 1995$$

A linear rate of increase in the stock of these homes has been assumed both between 1976 and 1985 and between 1986 and 1995. The Alternative Scenario assumes a linear rate of implementation of each passive conservation measure in these homes over the period 1976 to 1995:

- Insulation, I_4 = 4.9%/year
- Storm windows, S_4 = 4.9%/year
- Night set-back, N_4 = 3.7%/year

Market Penetration:

- Insulation, $I_4 = 2724(t-1975)-1362, \quad 1976 \le t \le 1985$
- $= 4410(t-1975)-10633, \quad 1986 \le t \le 1995$
- Storm Windows, S_4 = Same as for Insulation I_4
- Night set-back, $N_4 = 2057(t-1975)-1029, \quad 1976 \le t \le 1985$

  $= 3330(t-1975)-8029, \quad 1986 \le t \le 1995$

Initial Capital Costs in 1976 Dollars (Reference)

- Insulation = $171
- Storm Windows = $101
- Night set-back = $65

Financing

- Bank loan for 5 years at a real interest rate of 7%.

Space Heating Efficiency

- Weighted average annual thermal performance coefficients from the Alternative Scenario.

The results of analysis of the total annual costs to consumers (capital and energy) in the residential sector in the Alternative Scenario following the implementation of the passive measures are shown in Table 3.5-1.3.

3.5.2 Space Heating and Active Conservation Measures

Three active conservation measures were described in the Alternative Scenario, all of which are considered to be additive to the passive measures just described. These measures are:

a. The introduction of heat pumps as an alternative heating and cooling system that would replace the conventional resistance heating and air-conditioning systems in a fraction of the homes.

b. Solar space heaters as an alternative to electric resistance heating in a fraction of homes built after 1976.

c. Total energy systems (which were assumed to be fuel cell systems) which are also implemented only in the newer homes.

The procedure for calculating the economic impact of these active conservation measures also follows that described for the passive measures. These will not be repeated here, but pertinent data will be presented for each active measure. The one additional factor that is present in this part of the analysis relates to the additive nature of these measures mentioned earlier. These measures, implemented in addition to the passive measures, will result in additional electrical energy savings. These savings will be determined and factored into the overall residential sector energy demands in the Alternative Scenario. All capital costs were assumed to be financed for five years at a real interest rate of 7%.

3.5.2.1 Heat Pumps in Single-Family Residences Built Prior to 1976

The Alternative Scenario assumes heat pumps capture 1% of this market by 1985 and 5% by 1995. Since implementation levels by year were not specified as in the case of the passive conservation measures, a linear rate was also assumed in the case of the active measures. For the heat pump, therefore, the levels of implementation were taken to be 0.1% per year between 1976 and 1985 and 0.4% per year between 1986 and 1995.

TABLE 3.5-1

ANNUAL TOTAL COST STREAM (10^6 $) IN THE ALTERNATIVE SCENARIO FOR SPACE HEATING FOLLOWING IMPLEMENTATION OF PASSIVE CONSERVATION MEASURES IN THE RESIDENTIAL SECTOR (1976 Dollars)

YEAR	TOTAL ANNUAL COST BY RESIDENTIAL TYPE*				TOTAL ANNUAL SECTOR COST[1] (10^6 $)
	SF<76	SF>76	MF<76	MF>76	
1976	141	8	63	3	215
1977	148	16	64	6	234
1978	155	24	65	9	253
1979	167	33	68	13	281
1980	179	42	71	17	309
1981	181	51	70	20	322
1982	186	61	70	74	341
1983	190	71	69	28	358
1984	191	79	68	31	369
1985	191	87	66	34	378
1986	191	99	64	39	393
1987	188	110	61	44	403
1988	187	122	60	49	418
1989	186	133	58	54	431
1990	186	144	56	59	445
1991	184	153	54	63	454
1992	183	162	53	66	464
1993	182	170	51	70	473
1994	180	178	49	73	480
1995	178	185	48	76	487
TOTAL	3574	1928	1228	778	7508

[1] Costs are to nearest 10^6 dollars.

Market penetration of heat pumps in the homes considered here was determined to be:

$$HP = 20(t-1975)+368, \quad 1976 \le t \le 1985$$
$$= 80(t-1975)+1172, \quad 1986 \le t \le 1995$$

Since single-family homes built prior to 1976 already have heating and (possibly) cooling systems, the heat pump penetration into this market has to be treated as a retrofit penetration. Thus, a consumer with this type of home would have to pay the full cost of the heat pump system and not just an incremental cost. This cost was obtained from Reference 8 and is $2198 in 1976 dollars. The cost is assumed to be constant over the 20-year period. The annual maintenance cost for the heat pump, however, can be offset by the annual maintenance cost for the conventional heating and cooling system. It was assumed that the annual maintenance cost would be same in both cases, hence this incremental annual cost is zero.

The energy savings associated with the use of a heat pump arises because it consumes only half the energy that an electric resistance heater would consume to provide the same service (this is an Alternative Scenario assumption). Since the fraction of homes implementing the heat pump is known, the electric energy savings in these homes can be determined. The product of the annual electric energy savings and the corresponding electricity price in the Alternative Scenario gives the annual dollar savings associated with the use of the heat pump. The difference between the annual capital cost stream and the annual savings stream represents the net annual cost or savings associated with the heat pump for the consumer.

3.5.2.2 Heat Pumps in Single-Family Residences Built after 1976

The Alternative Scenario assumes that heat pumps are installed in 5% of these homes in the first year, with implementation levels increasing to 7% in 1985 and 15% in 1995. Following a linear rate of implementation over each 10-year period, the penetration of heat pumps in these homes was determined to be:

$$HP_2 = 1370 \text{ units in } 1976$$
$$= 122(t-1975)+1248,\ 1977 \leq t \leq 1985$$
$$= 680(t-1975)-1973,\ 1986 \leq t \leq 1995$$

Consumers who would own these homes have a choice of either installing a heat pump or the combination of conventional resistance heating and air conditioning. Thus the capital cost to the consumer who opts for a heat pump is actually only an incremental cost. This cost taken from Reference 8 was $609/per unit and was assumed to be constant over the period 1976-1995. Incremental annual maintenance costs were assumed to be zero. The annual electric energy savings in these residences following the implementation of heat pumps was computed as before.

3.5.2.3 Heat Pumps in Multifamily Residences Built After 1976

The market penetration of heat pumps in these homes was determined to be:

$$HP_4 = 111(t-1975)-56,\ 1976 \leq t \leq 1985$$
$$= 720(t-1975)-4436,\ 1986 \leq t \leq 1995$$

Incremental capital cost = $294

Incremental maintenance cost was assumed to be zero.

The results of the analysis of the implementation of heat pumps in the residential sector are shown in Figure 3.5-3. For single-family residences built prior to 1976, retrofitting with heat pumps is not cost effective. In these homes the incremental cost is the full cost of the heat pump. This results in capital expenditures approximately three times as large as the energy cost savings obtained. Additionally, since the heat pumps are installed in homes that have already been made energy efficient with the passive conservation measures, the total energy savings potential of the heat pump is drastically reduced. In other words, installing a heat pump in homes where no passive measures have been implemented would be expected to have a much better benefit/cost ratio, compared to the present situation where the ratio is about 0.4.

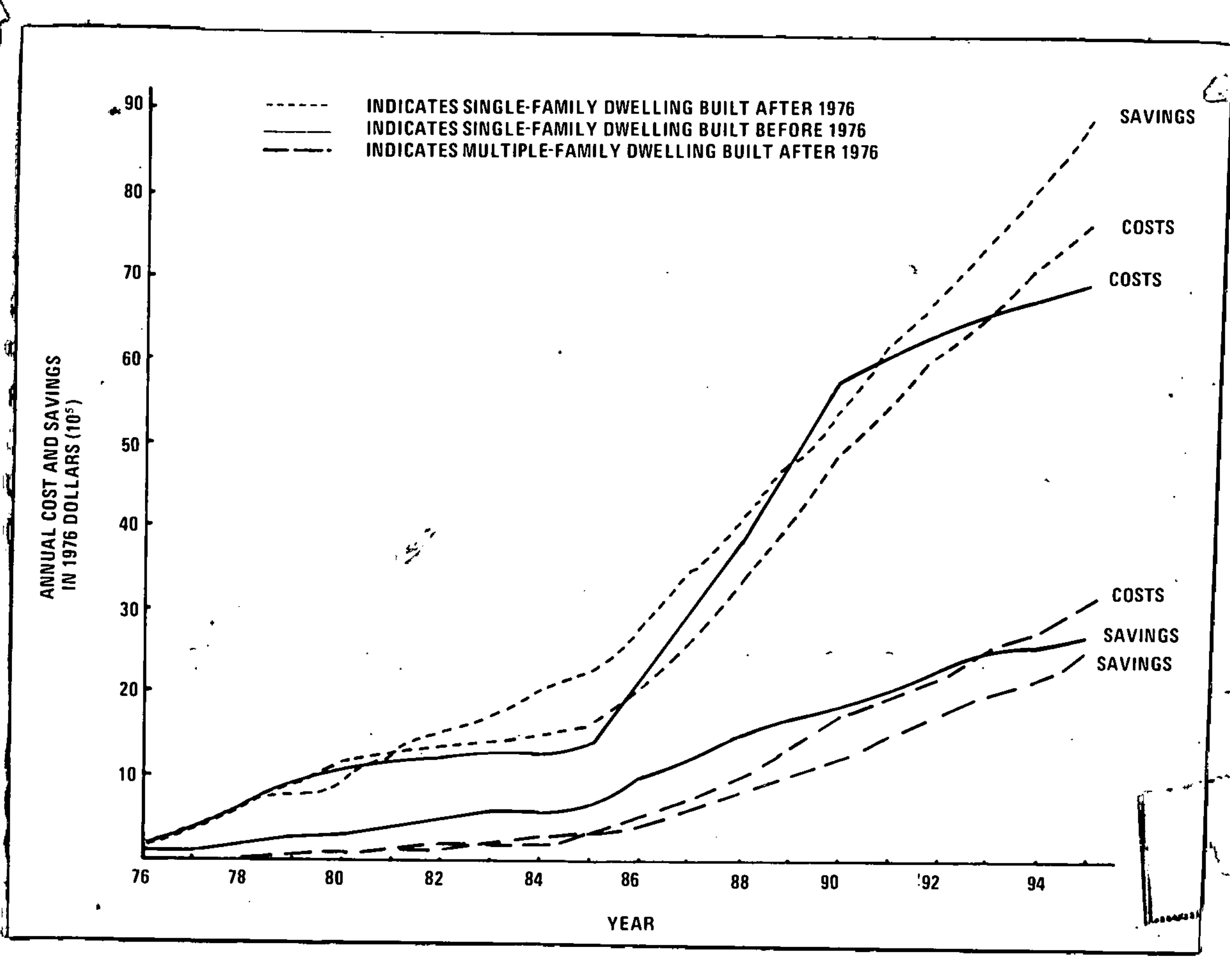


FIGURE 3.5-3. HEAT PUMPS IN THE RESIDENTIAL SECTOR

In single-family residences built after 1976, the installation of heat pumps is marginally cost effective with a benefit/cost ratio of 1.2. This is partly the result of the incremental cost being only $609 compared to $2198 for the existing homes. However, heat pumps are marginally cost ineffective in the new multifamily dwellings in spite of the low incremental cost of $209. This is due to the much smaller heating loads in these dwellings and consequently smaller potential for energy savings.

3.5.3 Solar Space Heating

Solar space heating systems have been assumed in the Alternative Scenario to be installed only in the new homes. Furthermore, these systems provide only 60% of the annual heating load of the residence. It was therefore assumed that all homes with solar heating would have full resistance heating backup. Consequently, the incremental cost of the solar system would be its full installed capital cost and, in addition, would have its specific annual maintenance cost.

The sizing of the solar collectors for individual single- and multiple-family dwellings was based on the following factors:

- Annual heating load of each building type (assumed to be the 1995 loads given in the Alternative Scenario).
- Distribution of average heating degree days by month in the Pacific Northwest region.
- Monthly average insolation in the region (Btu/sq ft).
- Monthly average collector efficiency based on heat delivered into the residence.

The calculation procedure for sizing the collector for residential buildings is identical to that shown in detail in Section 3.6 and Appendix E for commercial buildings in which solar heating was implemented and will not be repeated here. The results are presented in Appendix B. Following this procedure, it was estimated that single-family residences require a collector area of 225 sq. ft. to provide 60% of their annual heating demand and the corresponding size for multifamily dwellings was 95 sq. ft. One assumption that was made was that each multifamily dwelling unit would have its separate collector rather than one large collector serving several dwelling units in one building. This provides each user direct control of the system.

The installed cost of the solar heating system per square foot of collector was taken to be $20 (in 1976 $) over the period 1976-1985 and $15 (in 1976 $) thereafter.[1] Thus, based on the size of the collector

[1] The total system cost, expressed in dollars per square foot of collector, includes costs of collectors, fluid loops, storage, controls, structure, and installation labor.

required, the pre-1985 installed costs would be $4500 for a single-family residence and $1900 per multifamily dwelling unit. The cost for the single-family residence is within the range of $4000-$6000 often cited for such dwellings, and is near the lower end of that range due to the fact that it is an additive measure to the passive conservation measures. Each system would also have an annual maintenance cost of $25 (in 1976 $) which remains constant over the 20-year period. All capital costs were assumed to be financed for five years at a real interest rate of 7%.

3.5.3.1 Single-Family Dwellings Built after 1976

The penetration of solar heating in these homes is based on the Alternative Scenario implementation of 2% in 1985 and 8% in 1995. The market penetration obtained was:

$$SS_2 = 110(t-1975)-55, \quad 1976 \le t \le 1985$$
$$= 510(t-1975)-2861, \quad 1986 \le t \le 1995$$

Capital Cost (1976$)

Initial Installed Cost = $4500, $1976 \le t \le 1985$

= $3375, $1986 \le t \le 1995$

3.5.3.2 Multifamily Dwellings Built After 1976

The implementation levels in these homes as given in the Alternative Scenario are 1% in 1985 and 4% in 1995. The market penetration can be expressed as:

$$SS_4 = 56(t-1975)-28, \quad 1976 \le t \le 1985$$
$$= 270(t-1975)-1551, \quad 1986 \le t \le 1995$$

Capital Cost (1976$)

Initial Installed Cost = $1900, $1976 \le t \le 1985$

= $1425, $1986 \le t \le 1995$

As explained in the case of heat pumps, the energy cost savings obtained by virtue of installing solar collectors will be accounted for by considering the net difference between the capital cost outlay and the electricity cost savings.

The annual cost and savings stream associated with implementing solar heating is shown in Figure 3.5-4. It is evident from these results that solar space heating is not cost effective over the 20-year period since in both cases the benefit/cost ratio is only about 0.2.[1] This results from the high installed cost of solar systems, the relatively small amount of energy savings obtained in the already well insulated dwellings in which these systems were installed, and the low price of electricity at which these savings are made.

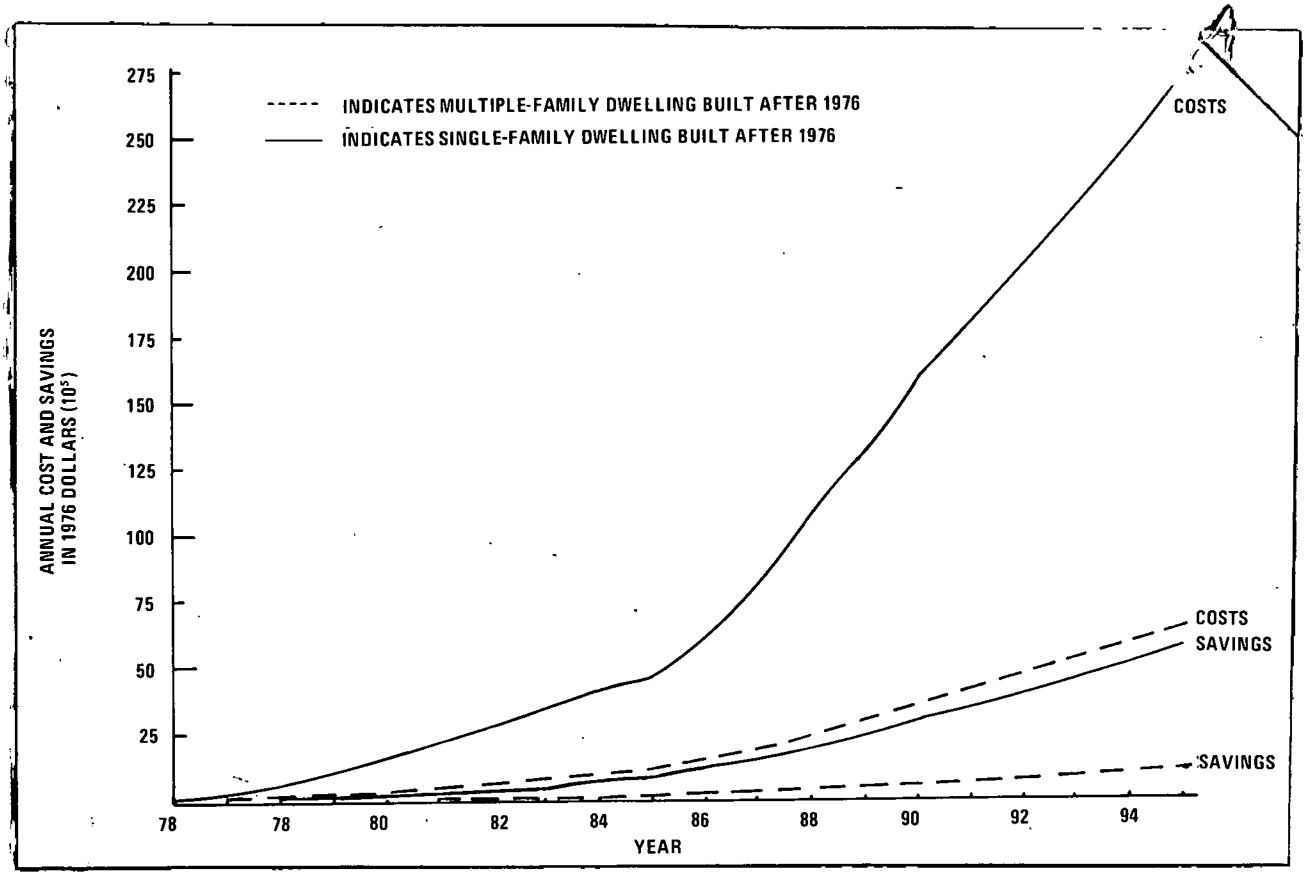


FIGURE 3.5-4. SOLAR SPACE HEATING IN THE RESIDENTIAL SECTOR

[1]Parametric analyses showed that lowering interest rates (to 2%) and lengthening financing periods (to 30 years) would not make solar heating cost effective.

3.5.4 Total Energy Systems (TESs)

Total Energy Systems were assumed to be natural gas-driven fuel cell systems. The Alternative Scenario considers these TES units to penetrate only the newer home market. These penetrations are 2% in 1985 and 10% in 1995 for the single-family residences and 1% and 5% for the multifamily residences. The implementation of TES obviates the need for utility power supply, since TES units produce electricity on-site. Further, the waste heat from the systems can be utilized to provide space heating and/or water heating. Consequently, the sizing of the TES capacity in either type of residence is a function only of the appliance related peak electricity demand. Space heat is a byproduct.

Peak appliance demand in the single-family residence was determined based on two factors given in the Alternative Scenario and mentioned below. The numerical details are given in Appendix C .

a. Average hourly electricity demand for each appliance type assuming 8760 hours/year i.e., average kW.

b. Ratio of individual appliance electricity demand (kW) at system peak to annual average appliance demand (average kW).

The product of the two factors gives the kW demand at system peak for each appliance. The sum of this product taken over all appliances then provides the total appliance kW electricity demand at system peak. It was assumed that this kW demand also represents the peak appliance demand in any year and hence the capacity of the TES. This capacity was determined to be 2.4 kW_e.

Since both single-family and multifamily dwellings have the same complement of appliances, identical TES capacity in both residential types was assumed.

It is necessary to know the extent of waste heat available from the TES, since this would determine the need for any backup heating systems to ensure that the building heating load is always satisfied. In order to know the extent of waste heat available from the TES, it is necessary to know the use profile of the TES, i.e., kW output per hour. This profile was assumed with peak use of the TES occurring in the winter months and is shown in Appendix C.

In the case of the single-family residence, the waste heat from the fuel cell was determined to be insufficient to meet the building heating load in November, February and March. However, in these months, the fuel cell was operating only at 50% capacity. Consequently, rather than provide a backup gas furnace to ensure adequate heating capacity in these months, it was considered to be possible to operate the fuel cell at a higher capacity (but within its maximum of 2.4 kW_e) and meet the deficit heating demand by providing an additional resistance heating element in the system. Thus, no gas backup systems were considered.

In the case of multifamily dwellings, the fuel cell waste heat was found to be sufficient to meet the space heating demand in all the months.

The incremental capital cost of the TES units and annual maintenance costs were obtained from data in Reference 9. The cost of the additional heating element was assumed to be $200. All capital costs were assumed to be financed for five years at a real interest rate of 7%.

The unit fuel costs (i.e., natural gas costs) for the TES units were calculated for each year based on cost data from Reference 18.

3.5.4.1 Single-Family Residences Built After 1976

It was assumed that TES units would be first available only in 1980.

Market Penetration of TES:

$$(TES)_2 = 91(t-1975)-228, \quad 1980 \leq t \leq 1985$$
$$= 340(t-1975)-2049, \quad 1986 \leq t \leq 1995$$

The incremental capital cost of the TES unit was $236 between 1980 and 1985 and $51 between 1986 and 1995 (Appendix C). Annual incremental maintenance costs were $31 over the period 1980-1995.

Fuel Costs:

- Annual fuel costs in total dollars are given by:

214.15 + 6.86(t-1981), $1981 \leq t \leq 1995$

Based on the assumption of unit costs ($/MMBtu) of:

2.007 + .0643(t-1981) (Reference 10)

3.5.4.2 Multifamily Residences Built After 1976

Market Penetration:

$$(TES)_4 = 185(t-1975)-463, \quad 1980 \leq t \leq 1985$$
$$= 720(t-1975)-4436, \quad 1986 \leq t \leq 1995$$

Incremental capital costs were $438 between 1980 and 1985 and $353 between 1986 and 1995 (Appendix C). Annual incremental maintenance costs were $31 over the period 1980-1995.

Fuel Costs:

- Annual fuel cost in $/MMBtu are given by:

  200.3 + 6.42(t-1981), $1981 \leq t \leq 1995$

The annual cost and savings streams associated with implementing TES in the residential sector are shown in Figure 3.5-5. The results show that TES units are not cost effective in this application since the benefit/cost ratio in both cases is less than 1. The ratio in the multifamily case is only 0.26 compared to 0.73 in the single-family case. This is because the incremental cost of TES in the multifamily dwellings is much higher due to the smaller conventional system that would otherwise be required for individual apartments and because the penetration of TES in these homes is twice as much.

3.5.5 Appliances

The Alternative Scenario appears to assume a complete turnover of electric appliances in each 10-year period, i.e., between 1976 and 1985 and 1986 and 1995 all appliances undergo replacement.[1] Included in the appliance category are electric water heaters and electric lighting.

Unlike in the implementation of the passive and active conservation measures, implementation of electric appliances takes place in all households that have these appliances according to saturation figures cited

[1]The Alternative Scenario seems to have set the market penetration of new appliances equal to the total saturation of electric appliances.

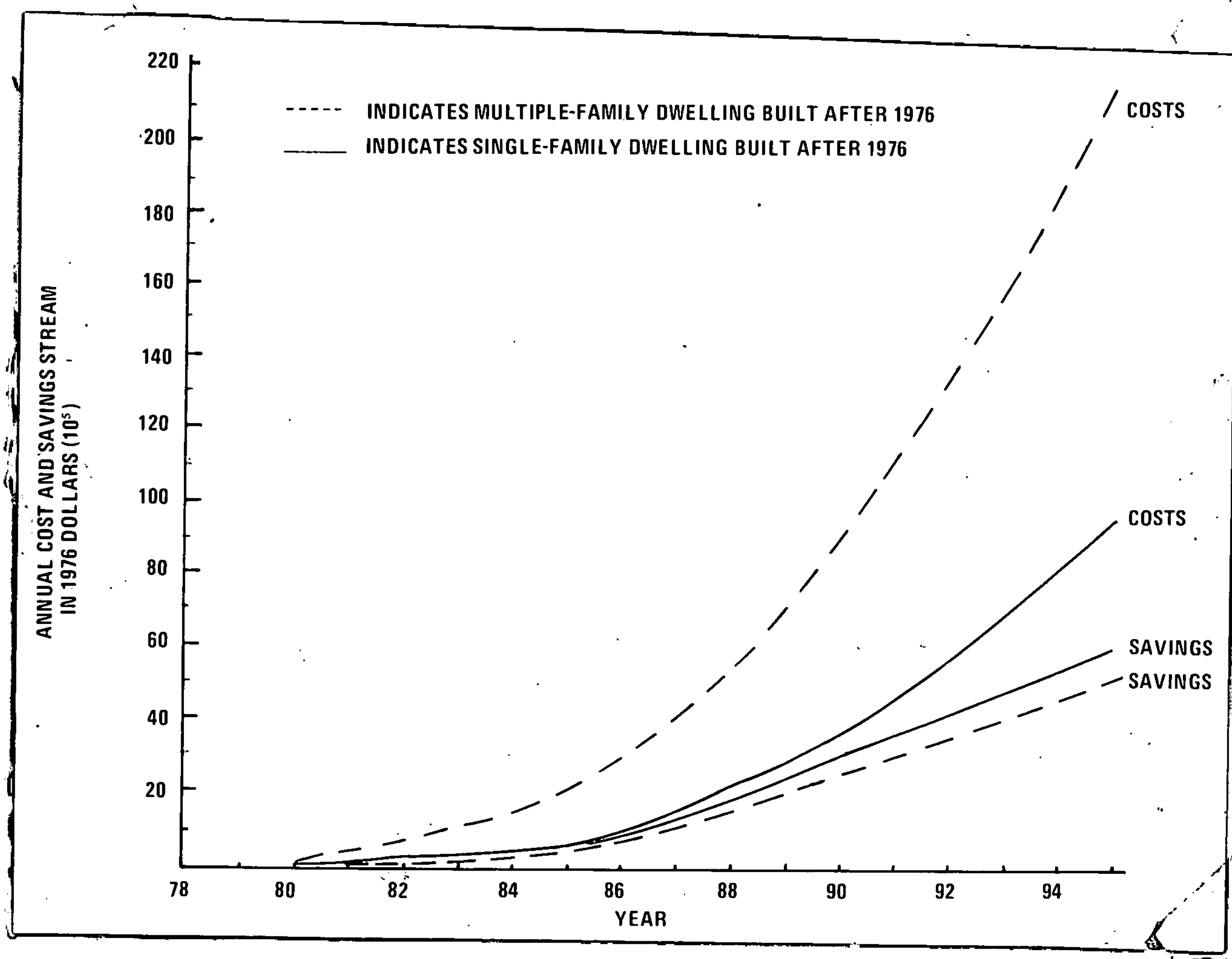


FIGURE 3.5-5. TOTAL ENERGY SYSTEMS (FUEL CELLS) IN THE RESIDENTIAL SECTOR

in the Alternative Scenario for 1985 and 1995. It was, however, assumed in this study that appliance saturation changes linearly between the limits specified for each 10-year period.

The capital cost expenditures for new appliances are shown and discussed in Section 3.4. In this analysis it was assumed that the incremental costs to the consumer in any year in relation to the costs in 1975 remain invariant over each 10-year period. Annual replacement costs are assumed to occur only in the case of lighting systems in which conventional incandescent lights are used. The newer energy efficient lighting systems are considered to have a lifetime of 10 years, so no replacement costs are associated with these in either of the two 10-year periods under study. As before it was assumed that capital expenditures are financed over five years at a real interest rate of 7%. This is a simplifying assumption because the distribution of consumers has not been determined according to the number of appliances (retrofit and new) bought in any year.

The sum of the capital and energy costs streams associated with the use of appliances in the Alternative Scenario is shown in Figure 3.5-6.

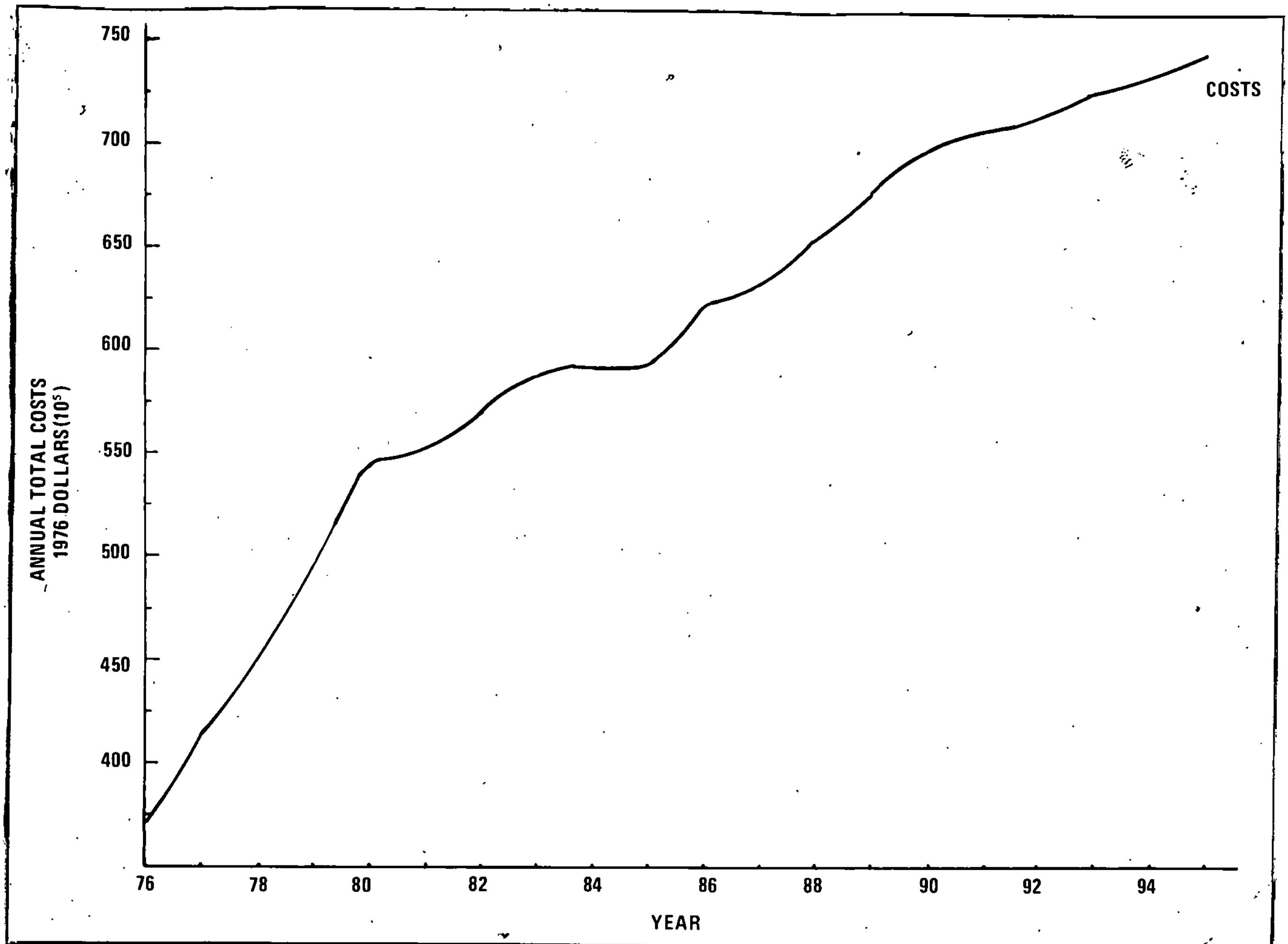


FIGURE 3.5-6. APPLIANCES IN THE RESIDENTIAL SECTOR

These annual costs appear the highest of all the measures considered so far partly because of their high turnover coupled with their very high saturations and partly because aggregate appliance electrical consumption is approximately twice as high as aggregate space heating consumption.

3.5.5.1 Solar Water Heaters

Solar water heaters are assumed in the Alternative Scenario to have penetrated about 2% of the homes in 1985 and about 20% in 1995. In addition, these systems are said to reduce the annual electrical energy requirement of conventional water heaters by 60%.

The solar collectors necessary for providing hot water were sized based on the factors described below and follow according to the same procedures described for solar space heaters. (See Appendix D for details.)

a. The annual energy required for water heating was taken to be 3510 kWh equivalent (1995 requirement in the Alternative Scenario).

b. Backup electric water heaters were assumed to be required wherever solar water heaters were implemented.

The calculated size of collector required to meet the specified requirements was 60 square feet.

Market penetration of solar water heaters can be expressed as:

$$SWH = 179(t-1975)+4191, \quad 1976 \le t \le 1985$$
$$= 2763(t-1975)+20969, \quad 1986 \le t \le 1995$$

The incremental capital cost (1976$) was the full cost of the system and was determined on the basis of $20 per square foot of collector in the period 1976-1985 and $15 per square foot thereafter.[1] Incremental annual maintenance costs were assumed to be $25 per unit (1976$). All capital costs were assumed to be financed for five years at a real interest rate of 7%. The annual cost and savings stream with the solar water heating systems are shown in Figure 3.5-7. The benefit/cost ratio for these systems is only 0.21, thus making their purchase unattractive for this application.

[1]This total system cost, expressed in dollars per square foot of collector, includes costs of collectors, fluid loops, storage, controls, structure, and installation labor.

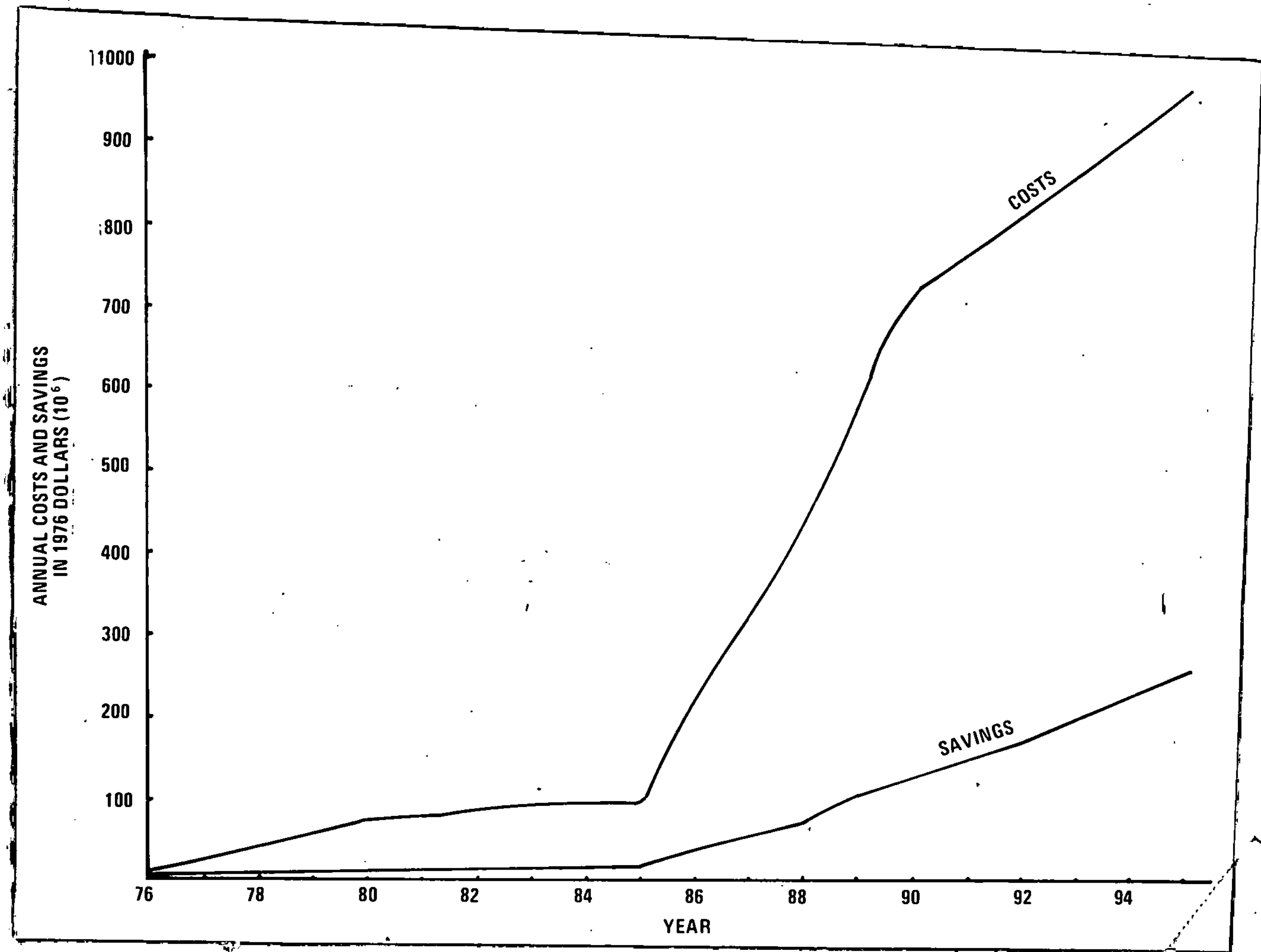


FIGURE 3.5-7. SOLAR WATER HEATING IN THE RESIDENTIAL SECTOR

3.5.6 Summary of Residential Sector Cost Analysis

Thus far all the cost factors of the individual elements of the conservation programs suggested in the Alternative Scenario for the Residential Sector over the period 1976 to 1995 have been described. Several variations were shown within the scenario in the benefit/cost ratio of individual conservation measures and by individual residence type. It is now possible to extend this comparison between the Alternative Scenario and the Power Plant Scenario for this sector as a whole.

The total cost (in 1976 dollars) in this sector in the Alternative Scenario adds up to 20.5×10^9 dollars. This compares to a total cost of 26.5×10^9 dollars in the Power Plant Scenario. Overall, the conservation program in this sector is more cost effective than the Power Plant Scenario with a benefit/cost ratio of about 1:3. When these costs are compared on a year-by-year basis, it is found that until 1982 the Power Plant Scenario costs are either just equal to or less than the costs in the Alternative Scenario. Thereafter, the BPA costs increase substantially reflecting the electricity price effect of new thermal generation, while the impact of the conservation measures on electrical energy demand begins to manifest itself in the Alternative Scenario. Of the total costs in the Alternative Scenario for the residential sector, approximately 33% (6.7 billion dollars) are due to incremental investment in capital, maintenance, and replacement costs associated with conservation technology, and the remaining 67% (13.8 billion dollars) is the cost of energy. Thus, the energy cost alone is approximately half the energy cost in the Power Plant Scenario.

3.6 COMMERCIAL SECTOR ECONOMIC ANALYSIS DESCRIPTION

The economic analysis of the NRDC conservation program for the commercial sector will basically follow the organization utilized in the discussion of the reconstruction of the Alternative Scenario for this sector. Namely, first the cost of implementing the (passive) building conservation measures will be determined (Section 3.6.1) and then the costs of implementing the (active) on-site systems, i.e., solar heating and total energy systems (Sections 3.6.2 and 3.6.3), will be analyzed. The final section (3.6.4) will discuss the overall costs incurred and total savings obtained due to the totality of proposed conservation measures in this sector.

3.6.1 Costs of Implementing Passive Building Conservation Measures

3.6.1.1 Capital Costs of Implementing Passive Conservation Measures

The procedure followed in order to compute the costs of implementing building conservation had to be different from that utilized in the residential sector, but nevertheless led to approximately the same kind of results. The procedure had to be different because the Alternative Scenario did not distinguish between existing and new construction for each of the building types and hence the typical decline in existing stock and growth in new stock could not be modeled. Nevertheless, the Alternative Scenario did follow the SOM Study's mandatory conservation program for this portion of the scenario as was done in the residential sector. Hence, the cost data and percent energy savings given in the SOM Study were applicable here as well and only the manner in which they were utilized to determine total cost differs from that utilized in the residential sector analysis.

The procedure utilized here is described using the 1985 calculation as an example. The regional electricity savings by building type given in the SOM Study were computed by summing the savings for the existing and new buildings of each type. Associated with that savings was a total capital cost of implementing those conservation measures for both new and existing buildings which were also summed by building type. Both the energy savings and costs were those associated with the mandatory conservation program given in the SOM Study and which was utilized in the Alternative Scenario energy savings calculation. The total savings and costs can then be used to compute a unit cost of implementing the mandatory program for each building type expressed in dollars per kWh_e saved. Then given the total electricity savings by building type in 1985 according to the Alternative Scenario, the total costs associated with those savings can be determined by dividing those total savings by the unit costs.

Although this was the conceptual approach used here, the actual approach was somewhat more complicated in order to take into account financing effects and replacement and maintenance costs. The financing effect on the total capital cost was incorporated through the use of a "loan multiplier." This "loan multiplier" is the annual capital recovery factor associated with the particular type of loan multiplied by the number of years of the loan. It results in a number greater than one which, when multiplied by the initial capital cost, yields the total expenditure for the capital cost at the time the loan is payed off. The results of these calculations are shown in the first five columns of Table 3.6-1 and Table 3.6-2 for the years 1985 and 1995, respectively.

TABLE 3.6-1

ALTERNATIVE SCENARIO COSTS OF IMPLEMENTING BUILDING CONSERVATION IN THE COMMERCIAL SECTOR THROUGH 1985

Building Type	1980 SOM Regional Savings (x 10^6 Kwh)	1980 SOM Regional Cost (x 10^6 $)	Loan Multiplier	1980 SOM Regional Cost[1] (x 10^6 $)	R&M[4] Added Cost (x 10^6 $)	Unit Cost ($/Kwh Saved)	1985 Alternate Scenario Savings (x 10^6 Kwh)	1985 Alternate Scenario Cost (x 10^6 $)
Small Office	613	73.7	1.116[1]	82.25	1.89	.1373	1231	169.0
Large Office	374	7.8	1.1881[2]	9.3	.60	.0264	1667	44.0
Retail	812	18.6	1.116[1]	20.8	1.38	.0273	1790	48.8
School	640	11.8	1.0790[3]	12.7	0	.0199	427	8.5
Other Commercial	1192	33.7	1.1881[2]	40.0	3.29	.0363	1802	65.5
								335.8

[1]7% interest for 3 years.
[2]7% interest for 5 years.
[3]5% interest for 3 years.
[4]R&M = Replacement & Maintenance Cost added for certain conservation measures. See Table 3.6-2

TABLE 3.6-2

ALTERNATIVE SCENARIO COSTS OF IMPLEMENTING BUILDING CONSERVATION IN THE COMMERCIAL SECTOR FROM 1986-1995

Building Type	1995 SOM Regional Savings (x 10^6 Kwh)	1995 SOM Regional Cost (x 10^6 $)	Loan Multiplier	1995 SOM Regional Cost[1] (x 10^6 $)	R&M Added Cost (x 10^6 $)	Unit Cost ($/Kwh Saved)	1985-1995 Alternate Scenario Savings (x 10^6 Kwh)	1995 Alternate Scenario Cost (x 10^6 $)
Small Office	2034	312.2	1.116[1]	348.4	11.0	.1767	1170	206.7
Large Office	2570	53.5	1.1881[2]	63.6	4.54	.0265	3574	94.8
Retail	5360	123.2	1.116[1]	137.5	5.32	.0266	1991	53.0
School	4217	79.0	1.0790[3]	85.2	0	.0202	720	14.6
Other Commercial	7689	218.0	1.1881[2]	259.0	21.3	.0365	3181	116.0
								485.1

[1]7% interestfor 3 years.
[2]7% interest for 5 years.
[3]5% interest for 3 years.

3.6.1.2 Maintenance and Replacement Costs Associated with Conservation Measures in the Commercial Sector

For each building type, both existing and new, the conservation measures implemented in it according to the SOM Study were examined, and those which involved a capital expenditure and which also possessed either a large number of moving parts or had a relatively short lifetime were selected as candidates for maintenance and replacement costing (Reference 4, pp. 146-171). However, due to the lack of data regarding maintenance costs and lifetimes associated with these measures in the SOM Study, an assumption had to be made. It was assumed that 10% of the initial capital cost of implementing these measures would be expended for maintenance and replacement during the ten-year periods of interest. This 10% figure may be too low for measures implemented early in the period and is certainly high for measures implemented later in the period and on balance is felt to represent a conservative average cost over each of the periods. The number of units of each measure implemented through 1980 and from 1981-1995 in the SOM Study was also determined. Thus, the total maintenance and replacement costs associated with the mandatory program in the SOM Study could be determined. The data are shown in Table 3.6-3.

TABLE 3.6-3

COMMERCIAL SECTOR MAINTENANCE AND REPLACEMENT COSTS ASSOCIATED WITH SOM'S MANDATORY PROGRAM

Building Type	Conservation Measure	1980 Unit Cost (1976$)	1980 # Units	1980 Total Cost (1976$)	1995 # Units	1995 Total Cost (1976$)
Small Existing Office	Electric Heat Pump	$ 270	2018	.54x10^6	13,453	3.63x10^6
Small New Office	Electric Heat Pump	$ 270	5022	1.35x10^6 1.89x10^6	27,265	7.36x10^6 11x10^6
Large Existing Office	Timer Controls	$ 500	34	17,000	236	.12x10^6
	Variable Air Volume System	$3500	35	.122x10^6	236	.826x10^6
Large New Office	Timer Optimizer Controls Heat Recovery System and Storage Variable Air Volume System	$6500	71	.46x10^6 .6 x10^6	557	3.6x10^6 4.54x10^6
Existing Retail Buildings	Modified HVAC Units	$2500	133	333,000	889	2.22x10^6
New Retail	Heat Recovery System	$3500	300	1.05x10^6 1.383x10^6	888	3.1x10^6 5.32x10^6
Existing Schools	NA	-	-	-	-	-
New Schools	NA	-	-	-	-	-
Other Existing Commercial	Low Capital Cost	$ 550	537	.295x10^6	3,577	2.0x10^6
	High Capital Cost	$1560	537	.838x10^6	3,577	5.6x10^6
Other New Commercial	Actions in Addition to ASHRAE 90-75	$2087	1034	2.16x10^6 3.29x10^6	6,578	13.7x10^6 2.13x10^6

These maintenance and replacement costs were added to the total capital expenditures after financing and then this total was divided by the SOM energy savings in the appropriate year to obtain the unit conservation costs by building type as explained previously. The unit costs were then divided into the total Alternative Scenario electricity savings to obtain the total cost, capital plus maintenance and replacement, of implementing the mandatory conservation measures by building type. These costs, according to building type, were distributed uniformly throughout each of these periods for purposes of obtaining an implementation schedule.

3.6.1.3 Cost of Electrical Energy to the Commercial Sector After Implementation of Building Conservation

Having determined the capital, maintenance, and replacement cost stream associated with implementing building conservation, the electrical energy costs to the consumer must now be determined. This determination is made by multiplying the energy consumption measured in kWh_e per year by the price of electricity in that year for each building type. It should be noted that the price of electricity utilized here is based upon the full implementation of the Alternative Scenario, and is not merely the price that would result from the demand reduction associated with these specific measures, nor even from the demand reduction associated with the entire commercial sector conservation program per se. Thus the price that is utilized to compute the energy cost to the consumer is actually contingent upon all the remaining conservation measures occurring as well (including those in the manufacturing sector).

The actual electricity consumption (as opposed to the effective electrical consumption presented in Section 2.3) by building type is shown in Table 3.6-4. These represent the regional electricity consumption for each building type in the years indicated. The consumption in the intermediate years was obtained by linear interpolation and multiplied by the price of electricity in these years. Thus the total cost of electrical energy in each year may be found.

Table 3.6-4

ACTUAL ELECTRICITY CONSUMPTION[1] IN THE COMMERCIAL SECTOR
BY BUILDING TYPE - ALTERNATIVE SCENARIO
(x $10^6 kWh_e$)

Building Type	1975	1985	1995
Small Office	2387	2700	3144
Large Office	2722	2815	1081
Schools	1502	1488	1139
Retail	5390	7734	11058
Other Commercial	6083	6539	5313
	18084	21276	21735

[1]Actual electricity consumption for each building type was determined by multiplying the regional building space by an energy intensity and then by electrical saturation as explained in Section 2.3.

These energy costs are then added to capital, maintenance, and replacement expenditures in each year. These data are presented graphically in Figure 3.6-1.

A comparison of costs with the Power Plant Scenario costs at this point shows that the total Alternative Scenario cost (in constant 1976$) is approximately 8.19 billion dollars while the total Power Plant Scenario cost is 14.65 billion dollars. However, it must be noted that the price of electricity utilized in computing the Alternative Scenario energy cost assumes the remaining active conservation measures were also implemented and thus there

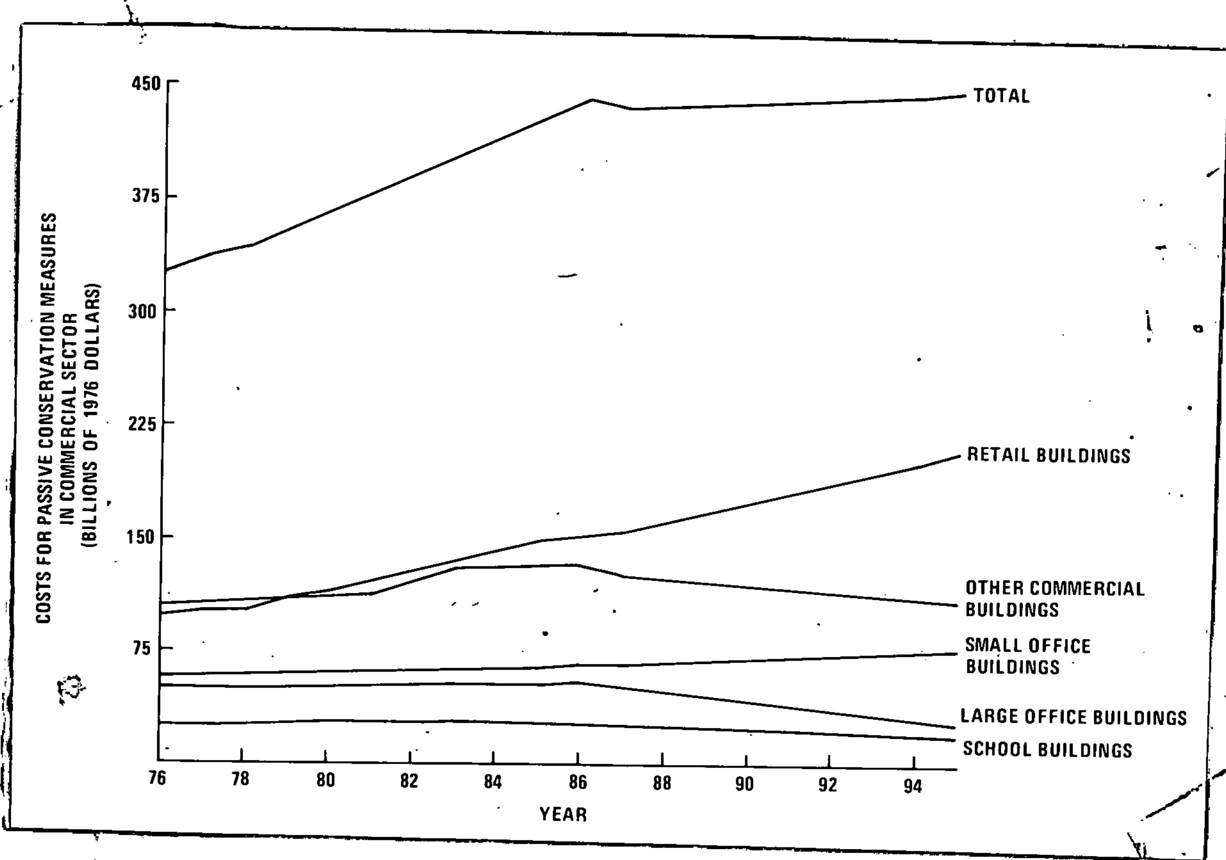


FIGURE 3.6-1. ALTERNATIVE SCENARIO COSTS FOR PASSIVE CONSERVATION MEASURES IN THE COMMERCIAL SECTOR

is a remaining cost associated with the Alternative Scenario that is not yet accounted for. Nevertheless, since the energy savings already obtained at this point is a significant percent of the total savings to be achieved, approximately 92% of the total savings in 1985 and approximately 84% of the total savings in 1995 (see Table 2.3-6), it is evident that there is a significant cost and energy savings associated with passive conservation measures alone.

3.6.2 Solar Heating Requirements

According to the Alternative Scenario, solar heating can save 1% and 5% of the total equivalent electrical energy (TEE)[1] requirements of the commercial sector for the years 1985 and 1995, respectively. In order to determine the cost of implementing this much solar heating, it must first be determined how much of the total sector's space heating service demand is provided through this much savings in TEE. This can be determined through the following table.

TABLE 3.6-5

SOLAR HEATING REQUIREMENTS

	1985	1995
Percent Savings	1%	5%
TEE[2] Saved (x 10^6 kWh)	503	2,355
Electrical Saturation[3]	.423	.461
Actual Electricity Saved (x 10^6 kWh)	212.8	1085.7
Space Heat Required (η=.95)(x10^6 kWh)	202.2	1031.4

Expressed in terms of Btu's, this means a total of 689.9 and 3549.3 x 10^9 Btu's of space heat must be delivered into commercial buildings of the PNW in 1985 and 1995, respectively.

3.6.2.1 Solar Collector Requirement for the Commercial Sector

In order to determine the cost of supplying these amounts of solar heat, the amount of area of solar collectors required to collect and deliver this heat must be determined.

In order to take into account seasonal and monthly variations of heating demand, a typical commercial building's heat load characteristics had to be described so that monthly variations in heat load requirements could be determined. The typical commercial building chosen here is a weighted average of the size of the SOM prototypes since the specific types of commercial

[1] The TEE represents the electrical equivalent of the sector's total energy demand.

[2] The total TEE before implementation of solar heating is 50,299 and 47,147 x 10^6 kWh for 1985 and 1995, respectively (see Section 2.3, Table 2.3-6).

[3] Reference 3, p. 169.

buildings in which solar heating was to be implemented were not specified in the Alternative Scenario report. Its heat load characteristics and calculated heat losses shown in the following table were based upon those of the large office building prototype (Reference 4, p. 124).

TABLE 3.6-6

AVERAGE COMMERCIAL BUILDING HEAT LOSS
CHARACTERISTICS FOR PNW
(Total Area: 39,500 ft^2)

ATTRIBUTE	AREA (ft^2)	U-FACTOR (Btuh/ft^2/°F)	$\dot{Q}$ (Btu/°F/hr.)
Walls	16,800	.251	4,217
Roof	8,000	.157	1,256
Floor	8,000 (160' x 50')	.40 (Btuh/ft)	16,800
Windows	6,700	1.13	7,571
Ventilation	10,000 (CFM)	1.008	10,080
			39,924 Btu/°F/hr.
			Q (daily) = 958,176 Btu/°F/day

The monthly heat load variations on the building were then determined by multiplying the daily degree-day heat loss Q (daily) by the number of degree days in the month. The degree-day data represented an average for the cities of Boise, Seattle, and Portland as found in the Climatography of the United States No. 84 (Table 1, Appendix E). Then, given the monthly solar insolation data for the PNW region (Table 2, Appendix E), an assumed collector size of 50,000 ft^2, and monthly variations in collector efficiencies,[1] the monthly solar heat supply was determined. (Since the percentage of total heat load to be supplied by solar was not specified, 70% was assumed from which the size 50,000 ft^2 was derived.) With this information, the monthly deficit (or surplus) from which an annual useful heat supply can be derived could be determined. These data and calculations are given in Appendix E, Table 3.

[1]"Application of New Energy Analysis to Consumer Technologies," Appendix G, Development Sciences Inc., E. Sandwich, Mass.

3.6.2.2 Capital Costs of Implementing Solar Heating Systems in the Commercial Sector

At this point, the amount of useful heat that can be supplied by 50,000 ft^2 of solar collectors into a typical commercial building has been determined. This amount of heat supplied per building divided into the total commercial sector heating requirement yields the number of buildings and hence the total area of solar collectors required. Given unit costs ($\$/ft^2$) for total installed solar heating systems,[1] the total sector cost can then be determined. These figures are shown in the following table.

TABLE 3.6-7

PNW COMMERCIAL SECTOR SOLAR COLLECTOR REQUIREMENTS

	1985	1995
Total Sector Heat Requirement ($\times 10^9$ Btu)	689.9	3549.3
Useable Solar Heat Per Building (10^9 Btu)	3.37	3.37
# Buildings	204.7	1053.2
# ft^2/Collector ($\times 10^6 ft^2$) [50,000 ft^2/building]	10.23	52.66
Cost ($\times 10^6$ 1976\$)[2]	204.6	841.0

3.6.2.3 Cost Stream for Solar Heating Systems in the Commercial Sector

The cost stream consists of the annual costs of capital plus the annual maintenance costs for each year in the period 1976-1995. The implementation rate was assumed to be uniform for each of the periods 1976-1985 and 1986-1995, and the capital costs thus obtained were assumed to be financed at a real interest rate of 7% for 5 years.

The annual maintenance costs were assumed to be \$100 per building throughout the entire period. Given that the number of buildings that implement the solar heating systems each year is 20.47/yr from 1976-1985 and 84.25/yr from 1986-1995 (based on the total number of buildings in Table 3.6-3), the annual maintenance costs are given by the following expressions:

1976-1985: \$100 (20.47) (t-1975)

1986-1995: \$100 (84.85) (t-1985) + 20,470

[1] National average costs for installed systems are approximately \$20/ft^2. (References 20 and 6.) Installed costs beyond 1985 were assumed to be \$15/ft^2 due to mass production cost reductions. The total system cost, expressed in dollars per square foot of collector, includes costs of collectors, fluid loops, storage, controls, structure, and installation labor.

Note that the supplementary electric resistance heating costs incurred because of the 30% deficit have already been accounted for by virtue of the fact that only the amount of electricity cost savings actually due to the implementation of the solar systems will be subtracted from the total sector costs. Hence the deficit is in effect charged at the rate of the current year's electricity price in each year. The size of the supplementary electric heating system was assumed to be the same as for the conventional system and therefore cancels out in the two scenarios.

The cost savings due to the reduction in electricity consumption occurred at the same rate at which the solar systems were implemented, namely uniformly. Based on the electricity savings shown in Section 3.6.2, the expressions governing these annual savings are:

1976-1985: $\$21.28\ (t-1975)\ P_e\ (t) \times 10^6$

1986-1995: $\$108.57\ (t-1985)\ P_e\ (t) \times 10^6$

where $P_e(t)$ is the price of electricity in year t expressed in $\$/kWh_e$.

3.6.2.4 Results of Economic Analysis of Solar Heating for the Commercial Sector

The cost and savings streams that result from the implementation of solar heating systems in the commercial sector are shown in Table 3.6-8.

The net cost of implementing solar heating systems is more than half a billion dollars. However, it should be noted that the implementation of this conservation measure does not occur in isolation from all the other measures but rather in conjunction with them. In particular, the cost savings are those associated with the relatively inexpensive price of electricity for the Alternative Scenario as a whole, and therefore the savings would, of course, be much higher if the solar heating systems were implemented first or in the context of the Power Plant Scenario. It must nevertheless be concluded that solar heating is not cost-effective within the context of the Alternative Scenario taken as a whole for the 20-year period of interest. Furthermore, given the fact that of the total energy savings in 1995 of 20.8×10^9 kWh_e the solar energy savings is 1.085×10^9 kWh_e, or approximately 5% of the total, it does not seem worth the expenditure of over half a billion dollars

TABLE 3.6-8

COST AND SAVINGS STREAM ASSOCIATED WITH IMPLEMENTING SOLAR HEATING SYSTEMS 1976-1995

(1976 Dollars x 10^{-7})

Year	Costs	Savings	Net Cost
1976	0.26	0.03	0.23
1977	0.52	0.07	0.45
1978	0.78	0.10	0.68
1979	1.04	0.14	0.90
1980	1.30	0.18	1.12
1981	1.56	0.22	1.34
1982	1.82	0.27	1.56
1983	2.08	0.31	1.77
1984	2.35	0.35	1.99
1985	2.61	0.39	2.21
1986	3.16	0.20	2.96
1987	3.71	0.39	3.31
1988	4.26	0.59	3.67
1989	4.81	0.79	4.02
1990	5.36	0.99	4.37
1991	5.91	1.19	4.72
1992	6.46	1.39	5.07
1993	7.01	1.59	5.42
1994	7.56	1.80	5.76
1995	8.11	2.00	6.11
		TOTAL	$576.6 x 10^6

to achieve this marginal savings when there are less expensive alternatives available. Of course, if the unit costs of solar heating systems can be further reduced, or collection efficiencies significantly increased, then this assessment could change.

3.6.3 Commercial Sector TES Requirements

The determination of the cost of implementing total energy systems (TES) proceeds in a similar manner to that of the solar heating cost calculation. First, a candidate TES must be selected since it is not specified in the Alternative Scenario report. Among the various types which are currently under consideration for the near-term are the diesel MIUS,[1] gas-fired internal combustion engine MIUS, coal MIUS, organic waste MIUS, and fuel cells.

[1] Modular Integrated Utility System.

The latter was chosen as the candidate system for purposes of this exercise. The reason for this is that fuel cells possess characteristics which are particularly suitable for integration with commercial buildings: quiet operation, low environmental emissions, high availability, modularity, and cycling flexibility.[1] The specifications for the particular fuel cell TES employed in the analysis are:[2]

- Rating - 40 kW
- Efficiency - 40% (part-load)
- Availability factor - 96%
- Water required - None
- Fuel - pipeline quality gas

The 40 kW_e fuel cell TES, a first generation system, is expected to be commercially available by 1980 according to one manufacturer.[3]

3.6.3.1 Sizing the Fuel Cell TES for a Typical Commercial Building

Following the method utilized in the solar heating requirement calculation, a typical commercial building was used as the basic unit for determining the amount of installed capacity required. The typical building chosen here was based on the SOM prototype large office building (Reference 4, pp. 124-125). The annual total electrical requirement for this all-electric building was given as 4,235,000 kWh per year. The portion of this electrical requirement used for heating was based on the Alternative Scenario average percentage of 49.2 multiplied by a 95% delivery efficiency or 1.979×10^6 kWh heat load. This leaves a purely non-heating electric requirement of 2.151×10^6 kWh, or a ratio of about .9 for thermal to electrical load. This ratio falls within the wide range of .5 to 4.0 usually cited for office buildings.

The fuel cell requirement for this typical commercial building is determined by assuming the fuel cell will be capable of meeting the peak demand for electricity incurred by that building at any time of the year.

[1]See "National Benefits Associated with Commercial Application of Fuel Cell Powerplants," United Technologies Corp. Power Systems Division, February 1976.

[2]Ibid., p. 14.

[3]Ibid., p. 49.

This assumption is implicit in the Alternative Scenario requirement that 100% of the electrical load be met by the total energy system. The peak demand can be determined from the data concerning non-heating electrical demand provided in Table 40 of Reference 3. The peak-to-average ratio that results is 2.54 as shown in Table 3.6-9 below.

TABLE 3.6-9

COMMERCIAL SECTOR: PEAK USAGE FOR NON-HEATING ELECTRICAL CONSUMPTION

End-Use Service	Peak to Average[1]	Relative Consumption (%)[2] (1985-1995)	Component of Peak to Average
Lighting	3.37	51.1	1.72
Cooling	1.87	25.5	.48
Mechanical	1.68	15.7	.26
Other	1.00	7.7	.08
		100.0	2.54

The maximum hourly demand for power that occurs at the time of the system peak (during winter) is calculated as follows:

$$\text{Peak Demand} = \frac{\text{Annual Non-Heating Demand x Peak to Average Ratio}}{8760}$$

$$= \frac{2.151 \times 10^6 \times 2.54}{8760}$$

$= 632.8\ kW_e$ Peak Demand

& $245.6\ kW_e$ Average Demand

The total number of 40 kW_e fuel cells required to meet this maximum[3] demand = 15.6, which may be broken down as follows:

	15	40 kW cells
plus	1	25 kW cell

for a total capacity of 625 kW_e (with 1.2 kW_e reserve).

[1]Reference 3, Table 40.

[2]Calculated from data in Reference 3, Table 41.

[3]Determining the number of fuel cells required based on meeting this peak, maximum demand will not result in the most economic number due to the amount of idle capacity that remains in off-peak periods.

Given this peak demand, which is assumed to occur during the month of December (since this month is one of the coldest months and has the shortest daylight hours which accounts for the high lighting peak to average ratio), the power demands for the remaining months must be determined such that the integrated power demand over the year equals the total non-heating electrical consumption for the building in that year. Since monthly power demands were not given in the Alternative Scenario report, a demand profile was constructed to serve this purpose, shown in Figure 3.6-2.

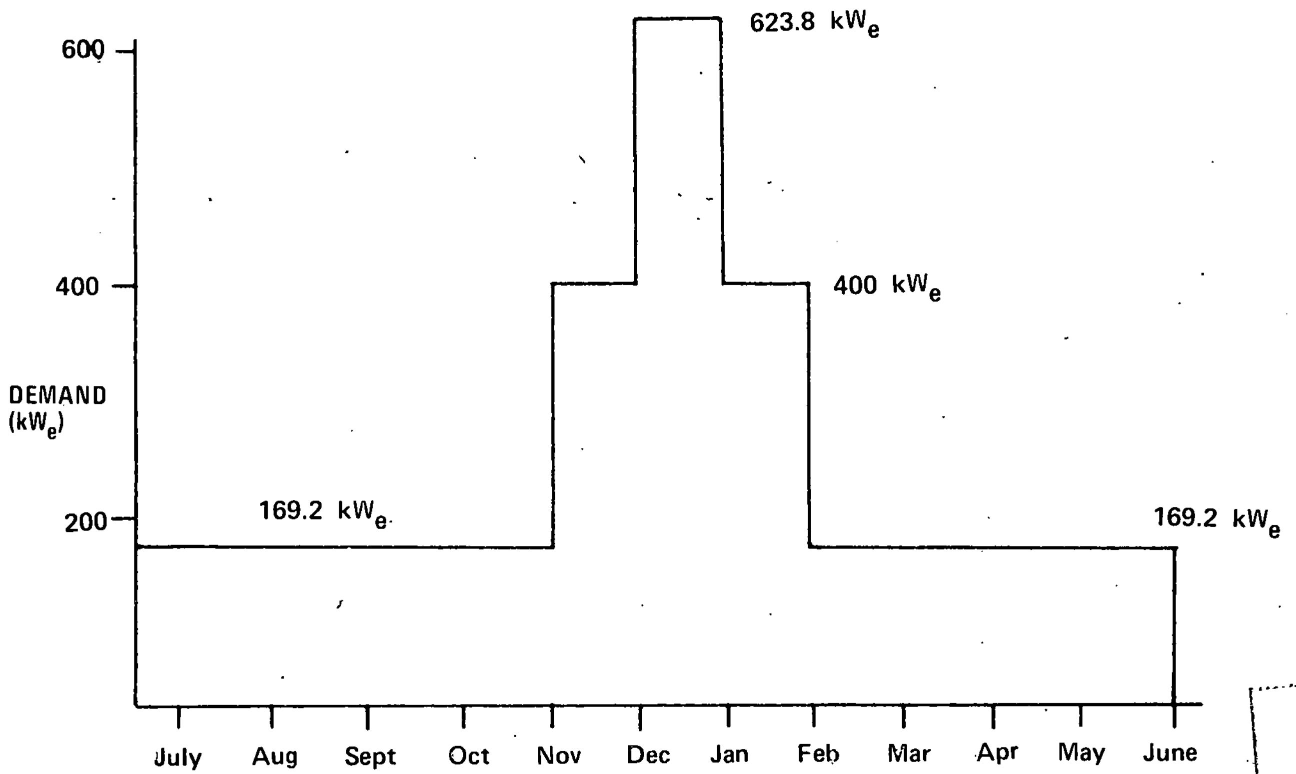


FIGURE 3.6-2. COMMERCIAL BUILDING NON-HEATING ELECTRICAL DEMAND PROFILE[1]

[1] Assumed profile, based on known average demand and demand at system peak.

Having determined the monthly demands for electricity (other than for heating), the recoverable waste heat output associated with these demands can be determined. Since the electrical conversion efficiency of the fuel cell is 40%, then 60% of the input energy in the fuel ultimately becomes a waste heat. Assuming a thermal recovery efficiency of 70% for this waste heat, then 42% of the input energy in the fuel is recovered as useful heat. The ratio of electrical to thermal conversion efficiency is thus 40:42 or 1.01:1.05, i.e., every kWh_e also results in 1.05 kWh_t. Hence, the monthly demands for electricity are multiplied by the factor 1.05 to determine the amount of useful heat recovered. This calculation yields the monthly supply of thermal energy (as well as electrical energy) from the fuel cell, shown in columns 2 and 3 of Table 3.6-10.

TABLE 3.6-10

MONTHLY THERMAL SUPPLY AND DEMAND FOR AN AVERAGE COMMERCIAL BUILDING WITH A FUEL CELL TEST

Month	kW_e Demand	Recoverable Thermal Output ($x10^3$kWh)	Heat Load ($x10^3$kWh)	Supplemental Heat Requirements ($x10^3$kWh)
January	400	307	350.3	43.3
February	169.2	130	264.3	134.3
March	169.2	130	258.4	128.4
April	169.2	130	175.0	45.0
May	169.2	130	101.0	-
June	169.2	130	45.4	-
July	169.2	130	13.6	-
August	169.2	130	16.3	-
September	169.2	130	48.1	-
October	169.2	130	141.6	11.6
November	400	307	245.5	-
December	623.8	478	318.8	-
			1979.0	362.6 (18.9%)

The monthly thermal loads of the typical commercial building were determined by allocating the annual thermal load of 1.979×10^6 kWh according to the percentage of annual degree-days occurring in each month (these percentages are the same as those occurring for the commercial building in the solar heating calculation). The monthly thermal demand and supplemental heat requirements are also shown in Table 3.6-10.

Table 3.6-10 shows that as well as being able to meet 100% of the annual electric power demand (the sizing requirement), the waste heat from the fuel cell is capable of providing 81.1% of the annual heating demands. The supplemental heat required could either be made up through a backup gas-fired furnace or perhaps by operating the fuel cell at a slightly higher capacity and utilizing the excess electricity for electric resistance heating. It was decided to test this latter option by determining whether there was sufficient fuel cell capacity to provide the supplemental heat requirement for the worst month, namely, February.

The total heat load for the month of February is 264.3×10^3 kWh (see Table 3.6-2). The electrical load for that month is 169.2 kW_e x 730 hours = 123.5×10^3. The total energy required in that month is therefore 387.8×10^3 kWh. Since the installed capacity of the fuel cell total energy system is 625 kW_e, it is capable of providing 456.2×10^3 kWh_e and 479.1×10^3 kWh_t at maximum output (see the month of December, for example, in Table 3.6-2), for a total of 935.3×10^3 kWh. This is more than sufficient to meet the load for the month with the worst deficit. Thus it will be assumed that with the addition of an electric resistance heating element, similar to that found in a conventional electric furnace, the fuel cell total energy system is capable of providing 100% of the energy requirements of the commercial building.

3.6.3.2 Capital Costs of Implementing Fuel Cell TES in the Commercial Sector

Having determined the installed capacity of fuel cells required to meet the total energy needs of a typical commercial building, the total capital costs of installing such a system must now be determined. Then, after determining the number of such buildings required to yield the total sector's reduction in the central station electricity requirements in 1985 and 1995, the total sector cost of implementing these systems can be determined.

The costs of each component and of the system as a whole are shown in Table 3.6-11. The installed unit costs of both fuel cell sizes were $\$277/kW_e$ and $\$200/kW_e$ in 1980 and 1986, respectively, as given in Reference 9 (high- and low-range estimates). The fuel cell thermal system cost was also given in Reference 9. The resistive heat element cost is an estimate based on the cost of the materials involved, and the equipment cost for the alternative conventional system was found in Reference 2 and scaled upward to meet the maximum hourly demand of approximately 1.6 MMBtu/hr. (month of January). Given the quantity of each component required, the cost of the total system when installed in each of the two time periods was found to be \$219,025 and \$170,900, respectively. Subtracting the capital cost of the alternative conventional system of \$12,700 produces a delta capital cost of \$206,325 and \$158,200. These amounts were assumed to be financed over 10 years at a 5% real interest rate.

TABLE 3.6-11
FUEL CELL CAPITAL COST PER BUILDING
(1976\$)

Component	Unit Costs[1] 1980-1985	Unit Costs[1] 1986-1995	Quantity		Total Cost Per Building 1980-1985	Total Cost Per Building 1986-1995
40 kW Fuel Cell	11,080	8,000	15		166,200	120,000
25 kW Fuel Cell	6,925	5,000	1		6,925	5,000
Fuel Cell Thermal System (including Heat Exchangers)	2,850	2,850	16		45,600	45,600
Resistive Heat Element (including Controls)	300	300	1		300	300
				Total	\$219,025	\$170,900
Alternative Conventional Electric Furnace Cost[2] (installed)					- 12,700	- 12,700
				Δ	= \$206,325	\$158,200

[1]Based on data supplied in "National Benefits Associated with Commercial Applications of Fuel Cell Powerplants," United Technologies Corp., Power Systems Division, Feb., 1976, pp.38-49.

[2]Building Construction Cost Data, 35th Edition, p. 205. Cost scaled for a 1.6 MMBtu unit.

In order to determine the total sector costs of implementing fuel cell TES, the number of buildings that would have them installed had to be determined. As was mentioned previously, since the Alternative Scenario report did not specify in which types of commercial buildings the TES would be installed, the typical commercial building assumed here had to be utilized. Having already determined that each building is provided 4.235×10^6 kWh of total energy per year by the fuel cell TES, it was only necessary to determine the total sector savings from the TES in order to finally determine the number of buildings required. The calculation of the total sector savings is shown in Table 3.6-12 below.

TABLE 3.6-12

COMMERCIAL SECTOR ELECTRICITY SAVINGS FROM TES

	1985	1995
Implementation	2%	10%
TEE Saved ($\times 10^6$ kWh)	1006	4710
Saturation	.423	.461
Electricity Saved ($\times 10^6$ kWh)	425.5	2171.3

Based on the amount of energy provided by a fuel cell TES as stated above, 100.5 and 512.7 typical commercial buildings would be required to implement them in 1985 and 1995, respectively (the fractional buildings imply buildings having that same fractional energy load of the typical building assumed here). Assuming a linear implementation schedule, this results in 20.1 and 41.22 buildings per year for the two periods of interest. Results are summarized in Table 3.6-13 below.

TABLE 3.6-13

CAPITAL COST STREAM FOR IMPLEMENTING FUEL CELL TES

	1981-1985	1986-1995
# Buildings Per Year	20.1	41.22
Cost Per Building ($\times 10^6$ \$)	0.206	0.158
Cost Per Year ($\times 10^6$ \$)	4.14	6.51

(Financed at a real interest rate of 5% for 10 years)

3.6.3.3 Operating Costs for Implementing Fuel Cells in the Commercial Sector

The operating costs for a fuel cell TES consist of fuel costs, and operating and maintenance (O&M) costs for the total system. The annual input fuel requirement is determined by dividing the annual output of electrical energy (thermal output is the waste heat by-product of this electrical energy) by the electrical conversion efficiency.

The annual output of electrical energy is the sum of the non-heating electrical demand of 2.151×10^6 kWh_e and the supplemental heating demand of $.363 \times 10^6$ kWh_e which equals 2.514×10^6 kWh_e. Dividing this total electrical output by the 40% conversion efficiency yields an input fuel requirement of 6.285×10^6 kWh_t or 21.44×10^9 Btu's. This is provided by natural gas.

The price of natural gas was based on FPC Opinion 770, which includes 4¢ per year increase in price. With a 1976 year-end price of $1.43 per MMBtu, the price at the beginning of 1980 would be $1.55 per MMBtu. Thus the equation for the price utilized here is:

$$\text{Price } (t-1980) = 1.55 + .04\,(t-1980).$$

The annual total fuel cost is thus 33.23 + .86 (t-1980) thousand dollars.

The O&M costs are based on the value of 1.11 mills/kWh_e (1976$) given in Reference 9, p. 39, for a large-scale intermediate load type plant. Based on an output of 2.514×10^6 kWh_e, this results in a cost of $2790/year.

Adding this to the fuel cost results in a total operating cost of 36.02 + .86 (t-1980) thousand dollars per year per building. This operating cost per building must be multiplied by the number of buildings in which fuel cell TES have been implemented for each year of the period of interest.

3.6.3.4 Results of Economic Analysis

The fuel cell TES cost and savings stream in constant 1976 dollars from 1976-1995 is shown in Figure 3.6-3. The cost savings stream was determined by multiplying the annual energy savings by the price of electricity in that year. The annual energy savings are directly related to the number of buildings in which the fuel cell TES has been implemented.

Figure 3.6-3

COST AND SAVINGS STREAM ASSOCIATED WITH IMPLEMENTATION OF FUEL CELL TES IN THE COMMERCIAL SECTOR 1976-1995

(1976 Dollars x 10^{-8})

Year	Costs	Savings	Net Costs
1976	0.000	0.000	0.000
1977	0.000	0.000	0.000
1978	0.000	0.000	0.000
1979	0.000	0.000	0.000
1980	0.000	0.000	0.000
1981	0.013	0.015	-0.002
1982	0.026	0.030	-0.005
1983	0.039	0.047	-0.008
1984	0.053	0.063	-0.010
1985	0.067	0.079	-0.012
1986	0.098	0.040	0.053
1987	0.120	0.079	0.041
1988	0.147	0.118	0.029
1989	0.176	0.158	0.018
1990	0.205	0.198	0.007
1991	0.229	0.238	-0.009
1992	0.254	0.278	-0.024
1993	0.280	0.318	-0.029
1994	0.306	0.359	-0.053
1995	0.334	0.400	-0.066
		NET TOTAL = -7.9×10^6 (net savings)	

The net savings over the 20-year period is $7.9 million. Therefore, the fuel cell TES is a cost-effective conservation measure even at the relatively low electricity prices of the Alternative Scenario. Hence, it is likely that such a system would be implemented, and that the greater the magnitude of implementation, the greater the magnitude of cost savings that would accrue to the commercial sector.

3.6.4 Results and Conclusions for the Commercial Sector Cost Analysis

The cost stream that results from the full implementation of NRDC's conservation measures (both passive and active) in the commercial sector is compared with the Power Plant cost stream in Table 3.6-14 below.

TABLE 3.6-14

COMPARISON OF ALTERNATIVE SCENARIO VS. POWER PLANT SCENARIO COST STREAMS FOR THE COMMERCIAL SECTOR 1976-1995

(1976 Dollars x 10^{-9})

Year	Alternative Scenario Costs	Power Plant Scenario Costs
1976	0.334	0.314
1977	0.341	0.334
1978	0.348	0.354
1979	0.366	0.393
1980	0.383	0.441
1981	0.392	0.469
1982	0.411	0.507
1983	0.430	0.578
1984	0.438	0.602
1985	0.448	0.657
1986	0.478	0.717
1987	0.473	0.785
1988	0.477	0.842
1989	0.481	0.896
1990	0.485	0.974
1991	0.488	1.030
1992	0.492	1.091
1993	0.496	1.160
1994	0.499	1.223
1995	0.503	1.287
	TOTAL = $8.76 x 10^9	TOTAL = $14.65 x 10^9

Thus, a substantial cost savings of 5.89 billion dollars in real dollars (not present-valued) is realized in the Alternative Scenario for the commercial sector. This accounts for nearly half (49.5%) of the total cost savings in the Alternative Scenario for the residential and commercial sectors. Similarly, the energy savings in 1995 for the commercial sector of 20.8 billion kWh_e is also approximately half of the total savings of 41.9 billion kWh_e in 1995 for both sectors combined. This results despite the fact that the starting point for conservation in the commercial sector, i.e., the energy consumption before conservation in the Alternative Scenario, is considerably less than the starting point for conservation in the residential sector, 39.3 and 71.8 billion kWh_e, respectively.

Another measure of the cost-effectiveness of conservation in the Alternative Scenario is the average cost of conservation expressed as cents per kWh_e saved. This measure can be quantified by dividing the total incremental capital and operating costs associated with the conservation technology (not including electric energy costs) by the total savings over the 20-year period. The total capital and operating costs were 1.8 billion dollars, while the total savings were approximately 190.4 billion kWh_e, which results in a price for conservation of approximately 1¢/kWh_e saved. This 20-year average cost is cheaper than the 1976 price of electricity of 1.62¢/kWh_e (produced) from which both scenarios begin and, therefore, conservation is generally cost-effective in both scenarios. Indeed the weighted average price of electricity delivered to the commercial sector over the 20-year period in the Power Plant Scenario is 2.20¢/kWh (as compared with 2.19¢/kWh for residential sector), more than a factor of two greater than the unit cost of conservation in this sector. The weighted average price in the Alternative Scenario is 1.78¢/kWh which is still greater than the unit cost of conservation. It must be recognized, however, that the incentive for the consumer to conserve at any point in time is always greater in the Power Plant Scenario than in the Alternative Scenario, and becomes progressively more so as the price of electricity rises. In summary, conservation is generally economical to implement both in gross economic terms and on a per unit cost basis in the commercial sector, even at the relatively low electricity prices of the Alternative Scenario.

3.7 SUMMARY RESULTS OF THE ECONOMIC ANALYSIS

This section summarizes the results of the economic analysis of the residential and commercial sectors in the Power Plant and Alternative Scenarios. Additionally, the cost of energy conservation and the cost of increased electricity supply within the Alternative Scenario itself are compared. These comparisons must be viewed in the following context:

a. The accounting procedures for energy consumption, energy savings and related costs of supply and conservation are truncated in the year 1995, consistent with the 20-year period of interest in the study.

b. The costs in the Alternative Scenario reflect both the conservation cost as well as energy costs. In the Power Plant Scenario only the energy costs are shown with capital cost effects (relating to use of conventional equipment) accounted for through considering only incremental costs in the Alternative Scenario.

c. The average price of electricity in the Alternative Scenario is derived on the assumption that all of the NRDC recommendations are implemented, i.e., inclusive of those in manufacturing and agricultural sectors.

d. Costs in the manufacturing and agricultural sectors have not been considered for reasons cited earlier.

The 20-year costs in the residential and commercial sectors across scenarios are shown in Table 3.7-1. The cost in the Power Plant Scenario for the combined sectors is $41.2 billion compared to $29.3 billion in the Alternative Scenario. It is interesting to note that the energy cost in the latter is only about half that in the former. This is the net effect of the inherently lower energy demand in the Alternative Scenario and the lower average blended price of electricity as a consequence of the much smaller inventory of new thermal generation in the scenario.

The average unit cost of conservation in the residential sector of the Alternative Scenario is 2.64¢/kWh, which is much higher than the cost of 0.92¢/kWh in the commercial sector. This is a result of two factors:

TABLE 3.7-1

COMPARISON OF TOTAL TWENTY-YEAR COSTS (1976$) BETWEEN THE POWER PLANT AND ALTERNATIVE SCENARIOS

Sector	POWER PLANT SCENARIO			ALTERNATIVE SCENARIO						
	Energy Consumption (10^9 kWh)	Total Cost ($10^9$$)	Average Electricity Price (¢/kWh)	Energy Conserved (10^9 kWh)	Conservation Cost[1] ($10^9$$)	Average Unit Cost of Conservation (¢/kWh)	Energy Consumption (10^9 kWh)	Energy Cost ($10^9$$)	Average Electricity Price (¢/kWh)	Total Cost[2] ($10^9$$)
Residential	1207	26.5	2.19	254	5.7	2.64	773	13.8	1.78	20.5
Commercial	666	14.7	2.20	190	1.8	0.92	393	7.0	1.78	8.8
Combined Sectors	1873	41.2	2.20	444	8.5 (29%)	1.90	1166	20.8 (71%)	1.78	29.3 (100%)

[1]Incremental Capital, O&M and Replacement Costs for Conservation Equipment.
[2]Conservation Cost plus Energy Cost.

a. The high marginal cost (¢/kWh) of conservation with the active measures which, because of being implemented over and above the passive measures, result in little additional energy savings. All of the four active measures in the residential sector were found to be cost ineffective as is shown in Table 3.7-2. In the commercial sector, only two active measures were considered in the Alternative Scenario and of these, one (i.e., total energy systems) was found to be cost effective.

b. The high turnover rate of all appliances over the 20-year period resulting in high capital expenditure for the consumers, but with relatively small energy savings overall because of the significant increase in energy consumption in the "Miscellaneous" appliance category. The commercial sector has no appliance category.

The high average unit conservation cost in the residential sector of the Alternative Scenario (2.94¢/kWh) relative to the cost of electricity supply in the Power Plant Scenario (2.19¢/kWh) must not be interpreted to mean that implementation of conservation is not cost effective in this sector. Cost effectiveness must be determined on the basis of cost equivalence relative to comparable amounts of energy savings and supply. As is clearly evident from Table 3.7-1 and from earlier discussions, the two scenarios are widely different with regard to their energy projections and therefore not amenable to this type of comparison.

TABLE 3.7-2

NET BENEFITS[1] OF ACTIVE CONSERVATION MEASURES IN ALTERNATIVE SCENARIO (1976-1995)

(10^6 1976$)

Active Measure	Sector	
	Residential	Commercial
Heat Pump	-31.8	N.A.
Solar Space Heating	-183.7	-576.6
Solar Water Heating	-577.7	N.A.
Total Energy System (Fuel Cell)	-98.0	+7.9

[1]A negative net benefit is a net cost (cost minus benefit).

A comparison of this nature can, however, be made within the Alternative Scenario by sector, by comparing the incremental cost of conservation and the cost of electricity supply equivalent to the amount of energy conserved. While energy consumption costs are not included in this comparison, it is nevertheless informative to contrast the capital expenditures involved in the before and after conservation cases.

The comparison of costs by sector within the Alternative Scenario is shown in Table 3.7-3. From a capital cost viewpoint, the expenditure for conservation in the residential sector is about 22% higher than the corresponding cost for supplying electricity if the conservation measures were not implemented. This difference is reduced to 13% when the high cost active conservation measures are excluded, since their contribution to electricity savings is quite small. The reason for the cost of conservation being higher even after excluding the active measures results from the appliance category impact discussed previously.

In the commercial sector, the cost of conservation is significantly lower than the cost of equivalent supply, even though the savings in this sector are comparable to that in the residential sector. Consequently, the total cost of conservation in the combined sectors is 11% lower than the cost of providing electricity equivalent to the total amount of energy conserved.

TABLE 3.7-3

HYPOTHETICAL COMPARISON OF THE INCREMENTAL COSTS OF CONSERVATION AND THE COST OF EQUIVALENT ELECTRICITY SUPPLY IN THE RESIDENTIAL AND COMMERCIAL SECTORS OF ALTERNATIVE SCENARIO, 1976-1995 (in 1976 Dollars)

Sector	Incremental Cost of Conservation ($10^9$$)	Cost of Electricity Supply Equivalent to Energy Conserved: Capacity Required[1] (MW)	Plant Cost[2] ($10^9$$)	T&D Costs[3] ($10^9$$)	Estimated Fuel & O&M Costs ($10^9$$)	Total Cost ($10^9$$)
Residential	With Active Measures : 6.68	3961	2.82	0.20	2.46	5.48
	(Without Active Measures: 5.42)	(3475)	(2.48)	(0.17)	(2.16)	(4.81)
Commercial	With Active Measures : 1.76	3171	2.26	0.16	2.00	4.42

[1]Calculated on the basis of 1995 electrical energy savings and assumed load factor of 0.75.
[2]$713/kW average through 1995.
[3]Assumed 7% of plant cost.

If a marginal pricing scheme were implemented for electricity generated by new thermal plants, benefit/cost ratios of the Alternative Scenario active measures would be improved if implemented by individuals paying marginal electricity costs. In this study, blended electricity pricing was assumed throughout in accordance with current practice. In any event, in the context of the Alternative Scenario, there would be few opportunities for marginal pricing, since few new power plants are required (even without implementation of the active measures).

4.0 INSTITUTIONAL IMPACT

4.1 INTRODUCTION

This section presents an evaluation of the institutional barriers which might inhibit or slow implementation of the initiatives postulated in the Alternative Scenario. The emphasis is directed to the Alternative Scenario in accordance with the objectives of the study defined in Section 1.3. Significant institutional problems are also associated with implementation of the Power Plant Scenario, particularly the well-publicized delays currently being experienced by utilities in attempting to obtain licenses to construct and operate new thermal plants.

Particular attention is given to the impact of the Alternative Scenario recommendation that would lead to phasedown of the regional aluminum industry. As stated in Reference 3, the recommendation is that BPA renew power supply contracts to aluminum plants only for those plants that are less than 35 years old when their current contracts expire. By this criterion, eight of the ten primary aluminum plants in the PNW would no longer be supplied power by 1995, and it is assumed that this block of power would be available to the rest of the regional consumers. Although it is noted in Reference 3 that the Alternative Scenario projects a power surplus by 1995 of 4,092 megawatts which would be sufficient to continue power service to all aluminum plants, it is recommended that this surplus be used instead as a contingency. Consequently, the analysis presented here considers the impact of the implementation of the aluminum phasedown recommendation.[1]

In the manufacturing sector, the Alternative Scenario modifies the employment mix between industries primarily to offset the direct loss in employment in the primary aluminum subsector. The basic BPA employment mix projections, as well as the Alternative Scenario modifications, are examined by comparison to national average projections for the various subsectors. The induced or ripple effects of these changes in employment mix, especially in service areas outside the manufacturing sector, are analyzed. Disruptive direct impacts on local communities are considered, in addition to the indirect effects on the entire region. A significant regional perturbation to a major industry such as primary aluminum will also have national impacts, and these are considered in the context of options available to the industry if the Alternative Scenario recommendation were implemented.

[1] There exists the possibility, regardless whether Alternative Scenario recommendations are implemented, that BPA may not have access to sufficient generating capacity in the 1980's to meet the total power needs of its preference customers as well as the aluminum industry.

The second major institutional problem analyzed concerns barriers that would affect implementation of conservation measures in the residential and commercial sectors.

Finally, considerations of capital requirements in both the Power Plant and Alternative Scenarios are evaluated.

4.2 ASSESSMENT OF REGIONAL IMPACT OF ALTERNATIVE SCENARIO

This section presents an analysis of the manufacturing sector employment data as shown in Table 4.2-1 (Reference 3, p. 66).

4.2.1 Assessment of the Employment Projections

The thrust of this assessment is directed toward the Alternative Scenario employment projections, with the BPA projections used as the point of reference. However, it is relevant to consider the accuracy of the baseline (BPA) employment projections as well, particularly if energy demand projections were based on total employment projections, thus using employment as a surrogate for demand. Analyses of regional population trends, which are related to total employment projections, are currently being conducted in other studies and were not included in the scope of this study.

As a means to the end of maintaining the growth rate in manufacturing employment projected by BPA while reducing the corresponding growth rate in energy demand, the Alternative Scenario posits its own employment projections across 16 manufacturing subsectors. By and large, these employment projections consist of BPA projections altered to favor employment in less energy-intensive industries at the expense of employment in energy-intensive industries. In the end, the Alternative Scenario approximates the total regional employment figures found in the BPA projections while reducing the corresponding electricity demand drastically. The proposed growth rates will be examined in light of locational determinants in relevant subsectors, existing regional manufacturing mix, and historical regional and national growth trends.

4.2.1.1 Subsector 2, Textiles and Apparel

The Alternative Scenario posits employment growth in this subsector of 24% by 1985 and 21% by 1995 relative to BPA rates of 21% and 15%, respectively. Nationally, the OBERS[1] projections show an initial employment increase in

[1]Office of Business Economics and Economic Research Service projections prepared for the U.S. Water Resources Council by the U.S. Dept. of Commerce, Social and Economic Statistics Administration, Bureau of Economic Analysis, Regional Economics Division and the U.S. Dept. of Agriculture, Economic Research Service, Natural Resources Economics Division.

TABLE 4.2-1

MANUFACTURING SECTOR--EMPLOYMENT (THOUSANDS OF PERSONS)[1]

SUBSECTOR NUMBER	SUBSECTOR NAME	1975 SCENARIO	1975 BPA	1975 RATIO SCENARIO/BPA	1985 SCENARIO	1985 BPA	1985 RATIO SCENARIO/BPA	1995 SCENARIO	1995 BPA	1995 RATIO SCENARIO/BPA
1	Food & Kindred Products	69.2	69.2	1.000	75.320	75.1	1.003	80.560	79.7	1.011
2	Textiles & Apparel	13.6	13.5	1.000	16.880	16.5	1.023	20.510	19.0	1.080
3	Lumber & Wood Products	135.6	135.6	1.000	132.000	132.9	0.993	106.800	108.0	0.931
4	Paper & Allied Products	28.2	28.2	1.000	29.690	29.9	0.993	29.540	30.1	0.981
5	Printing & Publishing	22.7	22.7	1.000	30.070	29.4	1.023	38.860	36.0	1.030
6	Chemicals & Allied Products	10.9	10.9	1.000	13.310	13.4	0.993	15.110	15.4	0.981
7	Petroleum & Coal Products	3.0	3.0	1.000	3.853	4.0	0.963	4.063	4.6	0.883
8	Stone, Clay & Glass	11.2	11.2	1.000	13.700	13.8	0.993	15.700	16.0	0.931
9	Iron & Steel	8.5	8.5	1.000	10.030	10.1	0.993	10.700	10.9	0.981
10	Non-Ferrous, Non-Aluminum	4.9	4.9	1.000	5.660	5.7	0.993	6.183	6.3	0.981
11	Primary Aluminum[2]	14.4	14.4	1.000	14.350	17.0	0.844	3.304	18.3	0.181
12	Fabricated Aluminum[3]	20.4	20.4	1.000	27.820	27.2	1.023	35.190	32.6	1.080
13	Machinery & Electrical Equipment	48.9	48.9	1.000	70.270	68.7	1.023	93.160	86.3	1.080
14	Aerospace Equipment	52.6	52.6	1.000	63.490	63.3	1.003	72.780	72.0	1.011
15	Other Transportation Equipment	28.3	28.3	1.000	38.490	38.0	1.013	47.570	45.3	1.050
16	Other Manufacturing	23.9	23.9	1.000	33.500	33.4	1.003	43.790	42.5	1.030
	TOTAL	496.3	490.3	1.000	578.400	578.4	1.000	623.800	623.8	1.000

[1]These data were taken from the Alternative Scenario report, Reference 3. BPA (Reference 101) has noted that certain of the employment figures attributed to BPA are in error. 1995 employment in subsector 11 is overstated by 3000 and subsector 7 by 400 which are offset by understatements of 1100 in subsector 9 and 2100 in subsector 10.

[2]Mainly primary smelting of aluminum, but includes some smelting of copper, lead, and zinc and rolling, drawing, and extruding of aluminum (Reference 101).

[3]Actually fabricated metal products, mostly non-aluminum (Reference 101).

this subsector of only 2.09% by 1985 followed by a decrease of 2.22% by 1995. Growth rates as high as projected by the Alternative Scenario for the Pacific Northwest region in this subsector are unlikely for a number of reasons. Traditional location theory identifies the primary factors in location of textiles and apparel plants as low regional wage structure and proximity to textile producers (Reference 24). Lately, empirical analysis has shown this trend to be somewhat offset by the negative consumer market implications of low regional wage structures such as low per capita income. In addition, the positive impact of spatial isolation markets has also resulted in some attraction of this industry to the West (Reference 25, p. 193). However, given the above considerations combined with the attraction of industry to warm climates (Reference 25, p. 183), the bulk of domestic production in this subsector occurs in the Southeast (45%), where average hourly wages ($3.40) are considerably lower than those for all manufacturing combined ($5.15, Reference 24, p. 268). Given low skill levels required of workers in this subsector, the tendency of the labor force to be female (81%) providing a second income source in households, and the relatively low capital requirements for plant construction, the industry appears to be rather flexible in selection of a location. Notwithstanding these factors, it is doubtful that a significant share of production in this sector will be drawn to the Pacific Northwest as assumed by both the Alternative Scenario and BPA.

4.2.1.2 Subsector 3, Lumber and Wood Products

Interest in this subsector stems not so much from the disparity in employment projections as from the general tendency of the projections to run counter to regional and national trends. The trend toward technological displacement due to higher productivity/employee can be seen in the OBERS projections which postulates employment by 1.78% to 1985 and decrease by 2.44% to 1995. In contrast, the Alternative Scenario and BPA project decreases by 1995 of 21.5% and 20%, respectively. Government economists project an upswing in demand for lumber and wood products as the residential construction market recovers and industrial demand expands (Reference 24, p. 36). Given the fact that this sector accounts for 30.3% of the regional labor force as opposed to 3.2% nationally (Reference 26, pp. 5-44), along with the optimistic outlook for demand, the regional rates of decrease in employment in this subsector put forward in both projections seem overstated.

4.2.1.3 Subsector 5, Printing and Publishing

BPA employment expansions for 1975-85 and 1985-95 are 29.52% and 22.45%, respectively. The Alternative Scenario figures are considerably higher at 32.47% and 29.23%, respectively. OBERS national projections indicate increases in the magnitude of 15.20% and 9.50%. Given the increasing importance of the region as a government center during the 1960's (government employment in the region increased 2.0% compared to 1.7% nationally during the period 1966-72) and given regional growth in finance, insurance, and real estate (4.3% regionally to 2.4% nationally for 1966-72), one might project a demand for printing and publishing that would lead to growth rates above the national average. The printing and publishing industry is heavily market-oriented and the Pacific Northwest offers the additional advantage of proximity to paper producers. However, the degree to which this industry will grow relative to national growth is subject to question. The fact that regionally it accounts for only 4.3% of all manufacturing employment compared with 5.7% nationally (Reference 24, pp. 5-44) would tend to weaken the argument for inordinate growth unless the region can expect to capture a share of the national market. Given the spatial isolation of the Pacific Northwest, this is not expected.

4.2.1.4 Subsector 7, Petroleum and Coal Products

Though the Alternative Scenario understates the BPA estimates for employment growth here (28.43% to 33.33% for 1975-85 and 5.45% to 15% for 1985-1995), it is the degree to which these figures overstate the national OBERS figures (1.51% for 1975-85 and -3.35% for 1985-1995) that draws attention to this subsector. Of the region's manufacturing employment in 1972, only 0.5% was in petroleum refining as opposed to 1.0% (Reference 24, pp. 5-44) nationally. Much petroleum refining tends to occur at ports receiving imported crude oil or in locations proximal to domestic crude sources. The completion of the oil pipeline in Alaska and possible shipment of the crude to the Pacific Northwest ports for refining could explain the inordinately high growth rates projected in the region. Again, the degree to which regional employment growth will supersede national growth is open to conjecture. A spinoff from petroleum refining activity in the region might be a petrochemical complex with by-products that might include synthetic textiles,[1] resulting in projected increases in that subsector. However, Reference 3 makes no direct mention of the possibility and hence it is assumed the projections for the two sectors are unrelated (in direct terms).

4.2.1.5 Subsector 9, Iron and Steel

Again, the two estimates are similar (both around +18% for 1975-85 and +77% for 1985-1995) while being quite dissimilar to OBERS projections (-8.24% for 1975-85 and -8.61% for 1985-95 for all primary metals). As the relative costs and ratios of inputs to iron and steel production have changed, the locational dynamics have changed also. Earliest sites were in areas replete with coal and not distant from ports handling iron ore. The trend now is toward market locations, the primary market for such goods being the Northeast and Midwest. The Pacific Northwest has definite disadvantages in terms of transport costs of raw materials due to its location (though western coal sites and iron ore from mountain states might provide useful inputs). As the steel industry seeks to expand, one might posit that its growth might be tied to an expanding regional market for iron and steel products and an attempt to produce more iron and steel locally for the regional market. Even in this case, the noted growth rates for employment in the iron and steel industry seem unduly high.

4.2.1.6 Subsector 11, Primary Aluminum

A major employment loss is projected by the Alternative Scenario (76.98%, 1985-1995) in this subsector as a direct result of the recommendation that long-term electric power contracts not be renewed with the majority of the region's primary aluminum producers. Implications of this recommendation are discussed later.

[1] Such an industrial complex was developed in Puerto Rico utilizing crude oil from Venezuelan fields. A detailed account may be found in Reference 27, pp. 434-474.

4.2.1.7 Subsector 12, Fabricated Metal Products

The relative Alternative Scenario/BPA rates for 1975-85 and 1985-95 are as follows: 36.3/33.33% and 26.49/19.85%. The OBERS projections are 9.23% and 5.37%, respectively. The overstatement of BPA figures by the Alternative Scenario is surprising in light of the suggestion that regional primary aluminum production be cut from 1,755 short tons/year to 568 short tons/year. At current levels, the lower production figure is more than adequate to meet regional demand. However, it is doubtful how the fabricated aluminum sector would respond to the loss in regional primary output. In order for the paradoxical primary/fabricated changes to occur, the 77% reduction in primary output would have to be allocated totally to markets outside the region with the remaining 23% used for expanded regional markets. Given existing long-term contracts between primary aluminum producers and fabricated aluminum producers, this might not be feasible. Also, given the rise in the price of primary aluminum products that might occur due to the shutdown of 77% of Pacific Northwest capacity, the rapid expansion of the regional fabricated aluminum market is unlikely. Alternatively, the increase would have to be achieved by the non-aluminum components of this subsector. It is doubtful that such would occur without many incentives to metal fabricators to relocate in the region. This projection is questionable.

4.2.1.8 Subsector 13, Machinery and Electrical Equipment

The Alternative Scenario/BPA figures for 1975-85 and 1985-95 are 43.7/40.49% and 32.57/25.62%, respectively, compared to 5.98% and 10.26% for OBERS. Machinery manufacturing employment accounts for 8.3% of all manufacturing employment regionally as opposed to 19.5% nationally. The greatest concentration of machinery and electrical equipment manufacturing is currently in the East North Central region, though the electronics industry has had substantial growth in the Pacific Northwest, primarily near Seattle. Such manufacturers are amenable to economies of agglomeration and proximity to markets, thus favoring the East North Central region. Regional employment growth at roughly three times the rate of national employment growth in the subsector would come only at the luring of both established and new machinery and electrical equipment manufacturers to the region. It is unclear to what extent the region is a net importer of goods from this sector, and it is equally unclear whether one can expect regional manufacturing to expand to meet all regional demands despite the relative historical weakness of this subsector in the Pacific Northwest. In the absence of a greatly increased regional demand for goods produced in this subsector, great abundance of inputs to this subsector regionally, or changes in transportation markets making remote production of the subsectors' goods economically infeasible, it is doubtful that this subsector will grow in the Pacific Northwest at three times the national rate.

4.2.2 Intersectoral Analysis

The employment data in Table 4.2-1 represent only a partial analysis of the employment consequences of the scenario differentials. Further ramifications are described in this section. Again, the BPA employment estimates are assumed to be the baseline, and the consequences of the Alternative Scenario revisions are examined.

The Reference 3 assertion "that regional employment will be the same as projected by BPA" (Reference 3, p. 169) is misleading. The data indicate only the direct employment effects of the Alternative Scenario. Consideration of the secondary effects occasioned by the scenario differential adds another dimension to the differential. The methodology used here for demonstrating the ramifications of revising BPA's employment projections should be taken as a heuristic exercise rather than a definitive forecast as it was necessary to make certain simplifying assumptions for the purpose of exposition.

The analysis is based on the data in Table 4.2-2 which refer to the same manufacturing subsectors as those listed in Table 4.2-1. The data in Table 4.2-2, however, expand on the information presented in Table 4.2-1 by indicating the total employment effects resulting from the two separate scenarios. The data in Table 4.2-2 indicate the employment adjustments required in the manufacuring and non-manufacturing sectors that are implied by the manufacturing sector scenarios presented in Table 4.2-1. Alternatively stated, the data listed in Table 4.2-1 represent only a partial exposition of the scenarios, whereas Table 4.2-2 is more complete.

TABLE 4.2-2

INTERINDUSTRY EMPLOYMENT ANALYSIS[1]

Subsectors	NRDC/BPA 1975 Employment (000)	1972 WIOM Productivity (Output/Employment) (in dollars)	1975 Regional Output per NRDC, BPA and WIOM (000,000)	1995 Employment per NRDC (000)	1995 Output per NRDC and WIOM (000,000)	1975-1995 Output Change per NRDC (000,000)	Employment per $1,000,000 of Final Demand per WIOM	Total Employment Change 1975-1995	1995 Employment per BPA (000)	1995 Output per BPA and WIOM (000,000)	1975-1995 Output Change per BPA (000,000)	Total Employment Change 1975-1995
1	69.2	68050.8	4709.1153	80.56	5482.1724	773.0571	53.2	41126.6	79.7	5423.6487	714.5334	38013.2
2	13.6	22434.8	305.1133	20.510	460.1377	155.0244	65.1	10092.1	19.0	426.2612	121.1479	7886.7
3	135.6	42124.2	5712.0415	106.800	4498.8645	-1213.1770	65.0	-78856.5	108.8	4583.1129	-1128.9286	-73380.4
4	28.2	59155.0	166.8171	29.540	1747.4387	79.2677	54.1	4288.4	30.1	1780.5655	112.3945	6080.5
5	22.7	22773.6	516.9607	38.860	884.9821	368.0214	78.7	28963.3	36.0	819.8496	302.8889	23837.4
6	10.9	48035.1	523.5826	15.110	725.8104	202.2278	55.2	11163.0	15.4	739.7405	216.1579	11931.9
7	3.0	28000.0	84.0000	4.063	113.7640	29.7640	14.0	416.7	4.6	128.8000	44.8000	627.2
8	11.2	40403.8	452.5226	15.700	634.3396	181.8170	66.0	11999.9	16.0	646.4608	193.9382	12799.9
9	8.5	34580.6	293.9351	10.700	370.0124	76.0773	64.2	4884.2	10.9	376.9285	82.9934	5328.2
10	4.9	27353.0	134.0297	6.183	169.1236	35.0939	67.5	2368.8	6.3	172.3239	38.2942	2584.9
11	14.4	104902.4	1510.5945	3.304	346.5975	-1163.9970	30.8	-35851.1	18.3	1919.7139	409.1194	12600.9
12	20.4	39880.0	813.5520	35.190	1403.3772	589.8252	53.3	31437.7	32.6	1300.0880	486.5360	25932.4
13	48.9	30608.7	1496.7654	93.160	2851.5064	1354.7406	63.0	85348.7	86.3	2641.5308	1144.7654	72120.2
14	52.6	44971.0	2365.4746	72.780	3272.9893	907.5147	43.7	39658.4	72.0	3237.9120	872.4374	38125.5
15	28.3	32814.6	928.6532	47.570	1560.9905	632.3373	52.7	33324.2	45.3	1486.5013	557.8481	29398.6
16	23.9	43517.8	1040.0754	43.790	1905.6444	865.5690	62.6	54184.6	42.5	1849.5065	809.4311	50670.4
Total								244549.0 127520.0 117029.0				264557.5 127520.0 137037.5

[1] References 28, 3.

The data in Table 4.2-2 were generated by the data in Table 4.2-1 using the relationships implied in the 1972 Washington Input-Output Model (WIOM), Reference 28. The relevant relationships extracted from the WIOM were those relating to subsector productivity and employment multipliers. These relationships were applied to the scenarios' employment data in order to examine the non-manufacturing employment adjustments required by the separate scenarios. Before proceeding with the methodology and results, it is necessary to indicate some background information on the workings of input-output studies and the multipliers derived therefrom.

Generally, input-output models demonstrate the interrelationships among sectors in an economy. Input-output analysis indicates that changes in one sector produce effects that "ripple" throughout an economy and result in an expansion or decline that is some multiple of the original change. The total effect of an initial change has been decomposed into direct, indirect, and induced effects. These several stages of income effects of an initial income decrease have been defined by Moore and Petersen (Reference 29) as follows:

> The direct income effects are measured by the decline in payments such as wages and salaries made in the (changed) industry; the indirect effects are the decline in income in all other industries which supply the original industry; and the induced effects are those which follow when, as a result of declines in their income, consumers 'slide down' their consumption functions and spend less on goods and services.

Such income changes also have multiple employment ramifications which are relevant to an evaluation of the differential in the two scenarios and are the changes brought out by the data in Table 4.2-2.

In order to proceed with the analysis, the following assumptions were made:

- The manufacturing subsector productivity relationships implied in the WIOM are applicable to the region and are constant over the period 1975 to 1995.
- The manufacturing subsector employment multipliers are the same for the region as for Washington State and are constant over the 1975 and 1995 period.

- The employment changes in the scenario are produced by changes in final demand.
- All other assumptions relevant to input-output analysis (Reference 30, pp. 309-363).

Given these assumptions, the analysis involved testing the total employment change differential implied between the scenarios in Table 4.2-1 by examining the total employment effect of the scenarios on the regional economy.

The total employment effects of the scenarios were derived through several stages. First, the 1975 manufacturing subsector employment data in Table 4.2-1 are multiplied by the output per man-year data derived from the WIOM. This yields dollar values output by subsector in 1975. A similar procedure is then used to obtain subsector output data for 1995 which is different for the Alternative Scenario and the Power Plant Scenario. Next, the 1995 output data for each scenario is subtracted from the 1975 output data which indicates the subsector output change over the period. The WIOM indicates that a given change in output (i.e., final demand) for any subsector will provide employment changes in the subsector itself, as well as in the subsectors that supply the original subsector and in the subsectors that sell goods and services to the employees in the original subsector.

The WIOM relates output changes to total employment changes through the multiplier concept discussed above. Multiplying the output changes by the WIOM employment multipliers yields the total employment change occasioned by the scenarios in each subsector. Adding the data for each subsector change for the total employment indicates the overall employment change over the period for each scenario.

At this point, it is necessary to separate the induced employment change from the total employment change. The induced employment effects are of interest here because these effects can reasonably be expected to occur outside the manufacturing sector. It will be recalled that the induced employment changes result mainly from employee spending in the non-manufacturing sector--the sector not included in the scenario data.

The data in Table 4.2-1 indicate that after all employment effects have been considered in the manufacturing sector, 127,500 jobs will have been gained under each scenario. When expanding the perspective on employment change to account for change in the non-manufacturing sector, the data and methodology embodied in Table 4.2-2 indicate that the employment gain made under the Alternative Scenario is less than that made under the Power Plant Scenario. More specifically, the Alternative Scenario precipitates a gain in employment in the non-manufacturing sector that is less than that in the Power Plant Scenario by 20,000 jobs.

Another aspect of the Alternative Scenario modification of BPA's employment projections needs to be considered. The Reference 3 statement that "the projected total employment for the manufacturing sector was distributed over the manufacturing subsectors in proportions different than the BPA forecast and in a way that would reduce energy requirements" implies restructuring the fabric of the economy. Presently, employment growth is a function of demand which, in turn, is a function of income, consumer preferences, etc. Indicating the ability to arbitrarily distribute employment implies an ability to manipulate incomes, consumer tastes, etc. This latter ability would require an authority which, up to the present time, is either administratively unobtainable and/or politically unacceptable.

4.3 REGIONAL AND LOCALIZED EFFECTS OF ALUMINUM DECLINE SCENARIO

4.3.1 Introduction

The Alternative Scenario notes that only 0.5% of the total regional labor force will be directly affected by the phasedown of most of the region's primary aluminum production. This aggregate figure, however, lacks sensitivity to the impacts of such an action on the actual communities in which the plants are located. The degree of impact that a plant has on its community is largely a function of the size and economic mix of the community. Changes in the interindustry ecology of the community, the local employment and earnings situation, and the financial resources of the local governments can be expected to occur relative to the community's size and economic diversity.

Using available data, these changes can be viewed through employment impacts and impacts on tax structure, both of which are reviewed herein. Additionally, one might examine interindustry linkages and spending data for local communities based on changes in the aluminum industry. However, the availability and reliability of such data limits this study to employment and tax impacts. The A. D. Little report to the Western Aluminum Producers, A Regional Analysis: Economic and Fiscal Impacts of the Aluminum Industry in the Pacific Northwest (Reference 31), provides a study of county-level impacts of the aluminum industry. This source was used extensively in the assessment conducted for this portion of the study.

4.3.2 Employment Impacts

The Alternative Scenario looked only at the regional direct employment impact of the aluminum industry phasedown. Here it is desirable to examine employment impacts at the local level as well. This is done by examining the direct, indirect, and induced employment related to the primary aluminum industry presently as a part of the total county labor force. Due to the possibility of compounding errors in estimation, this seems more reasonable than comparing projected layoffs to projected labor force levels at some future time. The methodology for derivation of the statistics found in Table 4.3-1 is discussed below, after which conclusions and suggestions for further analysis will be detailed.

4.3.2.1 Methodology

Direct employment figures on a local level for the primary aluminum industry are unobtainable via the Census of Manufacturers due to disclosure regulations. However, the A. D. Little study did obtain direct employment figures from the aluminum companies, supplemented by data from state employment agencies (Reference 31, p. 46). These 1973 statistics were used to detail direct employment. Two estimates of direct, indirect, and induced employment are shown. The first is also from the A. D. Little study (Reference 31, p. 46), and was derived by using a multiplier of 3.6 for total employment per aluminum employee.

TABLE 4.3-1

LOCAL LABOR FORCE ATTRIBUTABLE TO ALUMINUM PRODUCTION, INCLUDING DIRECT, INDIRECT, AND INDUCED EMPLOYMENT

Company	Plant	County	Aluminum Employment	Manufacturing Employment	Total County Employment	Direct, Indirect, & Induced (AD Little)	AD Little as percent of County Labor Force	Direct, Indirect, & Induced (WIOM)	WIOM as percent of County Labor Force
Alcoa	Vancouver	Clark, Washington	1,450	12,543	33,417	5,220	16	3,015	9.02
	Wenatchee	Chelan, Washington	1,000	2,626	13,653	3,600	26	4,797	35.13
Reynolds	Longview	Cowlitz, Washington	1,200	11,860	23,182	4,320	19	5,756	24.83
	Troutdale	Multnomah, Oregon	750	52,565	267,015	2,700	1	3,564	1.33
Kaiser	Mead	Spokane, Washington	3,500	13,944	84,106	12,600	15	6,031	7.17
	Tacoma	Pierce, Washington	400	20,653	92,889	1,440	2	2,220	2.39
Martin Marietta	Goldendale	Klickitat, Washington	600	1,566	2,826	2,160	76	3,289	116.40*
	The Dalles	Wasco, Oregon	500	1,225	5,305	1,800	34	2,604	49.09
Intalco	Ferndale	Whatcom, Washington	1,100	6,291	22,763	3,960	17	7,155	31.43*
Anaconda	Columbia Falls	Flathead, Montana	850	3,472	11,681	3,060	26	4,934	42.24
Alumax**	Umatilla	Umatilla, Oregon	(785)	--	(9,988)	--	--	(5,126)	(51.32*)

*These plants, being less than 35 years old at BPA contract expiration date, will not be shut down under the Alternative Scenario.

**The Alumax plant data is not currently on-line. Direct employment estimates are the author's, based on output/employee ratio of 0.23 short tons/year, derived from 1972 employment data from Ernst and Ernst, Energy, Economy Relationships, for BPA, June 1976, p. V-24, and output data from Rothschild and Company, June 30, 1976. The operating date of the facility has not been determined.

The second figure was derived based on the Washington State Input-Output Model (Reference 28) which estimated a total (direct, indirect, and induced) employment multiplier of 30.8 employees per one million dollars of aluminum final demand. Assuming the Washington State multiplier to apply to locations in Oregon and Montana as well, and assuming the multiplier to work equally well for incremental losses in output, the ton per year output of each plant (Reference 32) is multiplied by the 1976 producer price of 44.7¢/pound or $890/ton (Reference 33) to get dollar output annually. This figure is then multiplied by Washington State's multiplier of 30.8 to get total employment impact. The use of a regional multiplier in a local context may result in an ultimate overstatement of local effects as the indirect and induced unemployment need not occur in the immediate county. However, this methodology does yield results acceptable for this study.

4.3.2.2 Results

The statistics in Table 4.3-1 summarize the employment impacts of the aluminum industry locally in the region. Again, as seen most explicitly in the case of Martin Marietta's Goldendale plant, the output-based multiplier generally overstates the direct, indirect, and induced employment impacts in certain areas due to its regional nature and lack of geographical sensitivity. A possible explanation lies in the fact that plants in underdeveloped small towns rely on interindustry linkages and service inputs from larger regional centers. Thus, for example, the output-based total employment impact exceeds the employment-based total employment impact in Wasco County, Oregon, while it provides a low relative estimate in Clark County, Washington, as part of the Portland SMSA. This is in keeping with the notion of metropolitan areas being net exporters of services to outlying regions.

4.3.2.3 Conclusions and Further Inquiry

The results show that the magnitude of employment impacts can be expected to vary from very slight in the case of plant closings in metropolitan regions (Multnomah County, Oregon; Pierce County, Washington) to very great in smaller, less complexly developed regions (Chelan County, Washington; Wasco County, Oregon). Any decisions to phase out aluminum production facilities must take into account the net employment effects beyond initial plant employment.

While only impacting 0.5% of the region's total labor force, such a move as the Alternative Scenario has suggested could effectively ruin the economic bases of plant locations other than those in the region's SMSAs. Despite recommendations to the contrary, the effective mitigation of the effects of a relatively sudden unemployment rate increase is debatable.

Given adequate local-based data on employment mix and earnings, one might logically extend the employment impact study into the area of total earnings lost to the local economy by the loss of employment (and hence income) to households due to plant shutdowns. The issue is addressed in the A. D. Little study (Reference 31, pp. 47-49). There, the significant point is made that average earnings in the primary metals industries, and particularly the primary aluminum industry, are considerably higher than the average for all employment sectors combined. Thus, an estimated 2% of the county's employment in aluminum accounts for 2.9% of its payroll (Reference 31, p. 49). Louis Jacobson (Reference 34) details methodologies for estimating earnings loss via a regression model of income determination based on employment declines in the domestic steel industry. Such a methodology might be applicable to the aluminum industry and might present a viable avenue for future inquiry (Reference 31, p. 51).

4.3.3 Tax Base Impacts

As in Table 4.3-1, tax revenues attributable to the aluminum industry exist in the form of state and Federal personal income tax (except Washington which has no personal income tax), corporate income tax (in Montana and Oregon), business and occupation tax (in Washington) and local property taxes. Additionally, Washington has a 5% sales tax, which would reflect aluminum industry earnings via disposable income. Due to data availability and low reliability of indirect estimation techniques, the only straightforward empirical analysis comes via the local property taxes, levied on the county level. It must be conceded that an analysis of local tax base impacts noting only direct local taxes (excluding intergovernmental transfers) is fractional at best. Yet even the consideration of direct local property tax loss through plant closings allows one a clearer local picture of the Alternative Scenario impacts than is afforded in that study. The tax impacts discussed here are solely those that would result from a phasedown of the aluminum industry and consequently do not reflect partial offsets if the gains in other subsectors postulated by the Alternative Scenario were realized.

4.3.3.1 Methodology

Telephone interviews of county officials and aluminum companies were used to compile the data in Tables 4.3-2 and 4.3-3. The respondents were asked to give the assessed valuation of the local aluminum plant (both in terms of real and personal property), the appropriate levy rates, and total county tax revenues. State sales tax revenues in Washington state were estimated by

TABLE 4.3-2
LOCAL PROPERTY TAX REVENUES FROM ALUMINUM INDUSTRY PLANTS

Company	Plant	County	Assessed Value	Millage	Plant Tax Revenues	Total County Tax Revenues	Plant as Percent of County
Alcoa	Vancouver, WA	Clark, Washington	59,900,000 (35 million plants/25 million persons)	19.21	1,150,679	42,617,740	2.7
	Wenatchee, WA	Chelan, Washington	49,006,000	--	693,403	11,478,286	6.04
Reynolds	Longview, WA	Cowlitz, Washington	29,135,310 (also 20,737,900 cable)	15.74	785,154 (458,677)	25,009,756	3.14
	Troutdale, Oregon	Multnomah, Oregon	--	--	550,980	227,043,981	0.24
Kaiser	Mead, Washington	Spokane, WA	13,268,000[1]	20.00	265,360	61,000,000	0.43
	Tacoma, WA	Pierce, Washington	25,000,000 (20 million PP/ 5 million RP)	24.69	617,500	80,033,851	0.77
Martin Marietta[2]	Goldendale, WA	Klickitat, WA	--	--	1,154,475	3,193,303	36.15
	The Dalles, Oregon	Wasco, Oregon	18,719,560 (also pumps 116,380)	23.3 23.71	438,923 436,165 2,758	7,360,000 320,908,576	5.96
Intalco[2]	Ferndale, WA	Whatcom, WA	183,500,000	11.11	2,038,685	24,165,000	8.44
Anaconda	Columbia Falls, MT	Flathead, Montana	--	--	1,667,546	25,753,503	6.48

[1]Total of two plants/average.
2These plants will remain on-line according to the Alternative Scenario.

TABLE 4.3-3

APPROXIMATE DIRECT LOSSES IN TAXES
ALTERNATIVE SCENARIO ($ 10^3)

State	Sales Tax	State Income Tax	Federal Income Tax (10^3 $)	Corporation Tax
Washington	2432.7[1]	---	22052.0[2]	4370.49[3]
Oregon	---	Unavailable	2980.0	Unavailable
Montana	---	351.8[4]	2026.4	Unavailable

[1] Estimated by assuming $7.00/hour average wage for primary metals workers applies to primary aluminum, giving estimated annual earnings per worker at $14,000 (@ 2,000 hours/year). Assumed family size of 3. Used 1976 tax tables, Optional Sales Taxes.

[2] This assumed $14,000 average wages minus $750 x 3 = $2,250 deductions based on family size. Taken from U.S. tax tables 1976.

[3] 0.00424 = tax rate for manufacturing primary aluminum - only primary nonferrous metals - mostly composed of aluminum.

[4] Primary metals tax yield for Flathead County contains one primary metals plant - Anaconda Aluminum. Took total state primary metals withholding to total state withholding. Ratio applied to total Flathead County withholding. From State of Montana, Department of Tax Research.

assuming the statewide average earnings of an aluminum industry employee to be in the $14,000-14,500 range (the average BLS primary metals wage in Washington for 1976 is $7.00 x 2,000 hours per year). Family size was estimated at three. The sales tax figure, derived from the Instruction and Form 1040, 1976 Optional State Sales Tax Tables, was multiplied by the A. D. Little figure of 9,250 state primary aluminum employees to approximate direct sales tax revenues. Data collected reflect fiscal year 1976.

4.3.3.2 Results

Table 4.3-2 shows the relevant tax figures and allows one to view the aluminum companies' taxes as a percentage of local tax base revenues. The A. D. Little report presents similar data for FY 73 (Reference 31, p. 51). The percentage contribution of the aluminum industry to the local tax base varies from a low of 0.243% in Multnomah County, Oregon (Portland SMSA), to a high of 36.15% in Klickitat County, Washington. Again, the percentage of importance of the plant to local tax base varies inversely with the size and complexity of the community. Aluminum-based state sales tax revenues for Washington are approximately $2,432,700.

4.3.3.3 Conclusions and Further Inquiry

As stated above, the direct impact of plant closings on local tax base revenues varies from very little in large SMSAs to very severe in small, isolated regions. If data and a requisite methodology were available, a multiplier to determine indirect and induced losses to tax rolls due to production loss, unemployment, etc., would be valuable in this analysis. Likewise, the addition of data on state and Federal taxes emanating from the aluminum industry and returning to the community as intergovernmental transfers would serve to complete the analysis. Given such a data base, one might be in a better position to estimate the ability of the community to finance services such as schools, roads, etc., in light of the suggested shutdowns. Such data would also illuminate the situation of the cutback in public revenue in the face of necessary public programs to mitigate the negative effects of plant closings. Given a more complete data base and methodology for such analysis, one might be better able to investigate the complexities involved in the public revenue impacts vis-a-vis provision of public services.

4.4 NATIONAL AND INTERNATIONAL LOCATION

4.4.1 Introduction

The Alternative Scenario document addresses the national impacts of the aluminum industry phasedown by stating, "In the absence of an economic subsidy in the Pacific Northwest, new plants constructed to provide the country's requirements for aluminum probably would be located outside the Pacific Northwest and nearer to the source of aluminum ore (or, hopefully, recyclable aluminum) or the aluminum market, in order to reduce the costs of transportation" (Reference 3, p. 80).

The above statement forwards rather strong assumptions and omits consideration of a number of important factors. This section of the report will address the neglected issues while examining the validity of its assumptions. The analysis will deal with each of four locational alternatives open to the Pacific Northwest primary aluminum producers if current contracts are not renewed. Briefly, the alternatives are:

- The Pacific Northwest producers, unable to purchase power from BPA or power companies at any price, build their own power generators, generating electricity at high marginal cost.
- Unable to purchase power from any source at any price, primary aluminum companies active in the region are forced to relocate their facilities at sites possibly within the United States or abroad. This alternative must look at the industry's locational dynamics, investigating regional variation in power costs and availability, transport costs, substitution between raw material sources, as well as the effects of these factors on the price of domestically produced aluminum. The balance of trade impacts regarding both the change in price of American aluminum due to domestic relocation and the change in import/export ratios due to relocation outside the United States must be addressed.
- The primary aluminum producers active in the Pacific Northwest could close their plants, and make no attempt to shift production elsewhere. The lost domestic capacity would be made up by augmenting the current import rate.
- The Pacific Northwest aluminum producers are able to purchase electric energy at a "blended" as opposed to "marginal" price either from BPA or individual power companies. The price change in electricity costs has implications concerning the Pacific Northwest's regional advantage in the industry.

This section draws heavily on a study done by Ernst and Ernst (Reference 35) for the BPA, as well as investment reports prepared by L. F. Rothschild and Company (Reference 32) and the Oppenheimer Company (Reference 36). Additional data sources include the Bureau of Mines, Mineral Facts and Problems (Reference 37, pp. 37-66).

4.4.1.1 Alternative One: Construction of Power Plants by Aluminum Producers

Assuming by virtue of the recommendations of the Alternative Scenario that BPA power becomes unavailable to the eight older Pacific Northwest plants at any cost (which excludes Alternative Four), this is the only alternative which would allow the Pacific Northwest aluminum producers to maintain production at present locations. This option would require the aluminum producers to enter the electrical energy generation arena, with its attendant problems of financing expensive large-scale power plants, satisfying environmental and other institutional requirements for power plant siting and location of transmission lines, and operating within contraints imposed by regulatory agencies. Additionally, producers would need to decide between construction of power plants at each facility as opposed to construction of central station facilities to supply more than one plant. Either choice would pose particular environmental, institutional, and legal problems which would require resolution before plants could be built.

Notwithstanding these problems, this alternative would not be considered by an aluminum producer unless it could be shown to be economically feasible. Assuming an aluminum company financed the construction cost of a large-scale power plant, and recovered the capital expenditures through an internal "change" for electricity used, it would charge itself the marginal cost for new thermal generation (plus an acceptable rate-of-return for any equity investment). Assuming the marginal cost of electricity in the Pacific Northwest to be on the order of 30 mills/kWh for new thermal generation (relative to the current average purchase price of 3.2 mills/kWh), and assuming a power requirement of 8 kWh/pound, it is estimated that the price of aluminum ingot from the PNW plants affected would increase by roughly 20 cents/pound. Such an increased production cost, particularly in view of transportation cost disadvantage in the Pacific Northwest (Reference 12, p. v-39), makes this alternative as stated infeasible.

4.4.1.2 Alternative Two: Shifting Lost Pacific Northwest Capacity to Alternate Location

By individual firm, the production capacity lost if the Alternative Scenario recommendations are followed are tabulated below:

Company	Pacific Northwest Capacity (10^3st/y)	Proportion of Capacity in PNW	Proportion of Capacity Lost
Alcoa	285	18%	18%
Reynolds	340	35%	35%
Kaiser	301	42%	42%
Martin Marietta	215	100%	44%
Anaconda	180	60%	60%
Intalco	261	100%	0%
Total	1,582	(total capacity lost = 1,201)	

The national impacts of the loss of this capacity are felt both by the aluminum industry as a whole, which must attempt to maintain the capacity level lost due to shutdowns (1201 x 10^3 st/y = 21.7 percent national output), and by each firm which loses a given percentage of its total production capacity. In shifting this aluminum production to alternate locations, one must accept the fact that power costs will inevitably increase over their Pacific Northwest rates. Beyond that, one must include the capital costs of new construction, which have been estimated at 9 cents/pound of plant output (Reference 36), resulting in a total of $217,800,000 of capital costs for displaced production.

Ernst and Ernst did a limited comparative cost study for a Pacific Northwest site versus a hypothetical Ohio Valley site. The replacement cost per pound for a plant outside the Pacific Northwest was estimated at 41.2¢ (Reference 35, p. v-38). The cost of replacing Pacific Northwest plants, accounting for 21% of our national aluminum output, with installed costs of 36.2 cents/pound at 80% capacity (allowing for IRE) and with alternate locations whose estimated cost per pound is 41.2¢, would effectively raise the market price of domestic primary aluminum. Though the magnitude of change on the average price of aluminum is not readily discernible, one can only estimate that to raise the price of traditionally low-cost American aluminum relative to Asian and European aluminum (the price differences are currently in the area of 8 cents/pound, Reference 38) would only augment the current import rates, which already favor foreign producers, as the tight American market became tighter.

The decision as to an alternate location for displaced production raises interesting issues. The added costs of relocation outside the Pacific Northwest might be augmented by various other factors. All of the alumina imported from Australia to smelting plants in the United States is utilized by Pacific Northwest plants. To shift production eastward, presumably to other low power cost areas such as the Tennessee Valley or Ohio Valley, would necessitate increased transport costs derived from the land transport of Australian alumina from West Coast ports or from the added water transport costs involved in using Gulf or East Coast ports. Such a shift in plant sites might lead smelters to seek alumina from closer sites, presumably Jamaica and Surinam. However, Jamaican and Surinese alumina is more expensive than Australian alumina ($115,03/ton vs. $93.67/ton. (Reference 38, pp. 6-7). The estimated total costs (production plus transport) of Australian alumina is $101.05/ton versus $120.19 for Jamaican/Surinese alumina. The cost advantage of Australian alumina derived from its utilization at least cost West Coast locations may be negated by shifting its market east. This might also serve to raise the cost of producing domestic primary aluminum.

Beyond consideration of alternative United States sites for production, it is likely that American aluminum producers might seek production sites in foreign countries. The argument growing out of the widespread use of aluminum by the ordnance industries during World War II and the Korean conflict that aluminum production for domestic demand, as a "strategic" industry, must be carried on within the United States has weakened considerably as aluminum has become more widely used in less "strategic" industries. It is likely, therefore, that, in order to maximize profits and maintain competitive price levels, American aluminum producers might seek foreign production sites should domestic sites appear unprofitable.

It is suggested that further analysis examine the proclivity of American primary aluminum producers to locate near sources of bauxite or aluminum

(Australia, Jamaica, Surinam) or in areas of cheap power. It is doubtful that American producers would seek European locations as electric power is extremely expensive (35-50 mills/kWh, Reference 38, pp.11-2). Regardless of the specific site chosen, the movement of production to foreign locations would result in labor displacement, and increase in the already high rate of imports and generally high prices of aluminum

Of course, location decisions are made at the level of the individual firm and not on the basis of industry-wide costs. It may well be that individual firms, by locating in a dispersed manner, can mitigate the problems caused by agglomeration in the Pacific Northwest, i.e., 0.5% of the labor force involved in an industry using 26% of the region's power. Likewise, the ability of each firm to absorb the costs of relocating might be a function of the firm's total capacity to be relocated, i.e., Alcoa only losing 18% of its national capacity may be able to absorb rising costs better than Anaconda, forced to relocate 60% of its aluminum capacity. Perhaps this will act to decide which plants will be relocated and which will merely be closed. Finally, the added costs of relocation may only be effective in the short run, given new technologies which allow for much more energy efficiency in production. Some form of this alternative seems most feasible.

4.4.1.3 Alternative Three: Closing of Pacific Northwest Plants, No Relocation, Demand Met by Increased Imports

This alternative is unlikely. To begin, the likelihood that aluminum producers will drop 21% of their national capacity is, in general, dubious. This would reduce the United States' share of world output, based on 1973 figures, to 26% from 34%, and would have grave effects on the balance of output between free world and Eastern Bloc producers. This alternative seems least probable.

4.4.1.4 Alternative Four: Purchase of Electric Power in Pacific Northwest at "Blended" Rates by Aluminum Industry

Given the price increases and general market disruption inherent in the three preceding alternatives, it seems worthwhile to address the possibility that Pacific Northwest producers might be able to purchase required electrical power at rates somewhere between the current 3.1 mills/kWh and the projected marginal 25-30 mills/kWh. This lies somewhat outside the realm of the Alternative Scenario, yet poses the most viable alternative. The "blended" BPA cost would be figured by requiring consumers of energy to pay a stipulated "high" rate for one-quarter of their BPA power (Reference 39, p. 3). Depending upon the mix of high-cost thermal and low-cost hydroelectric power, the blended price of electricity as sold directly to industrial customers (thus not including utility distribution charges) could vary from 10 to 18 mills/kWh. According to the Ernst and Ernst study, a power price increase to 9 mills/kWh would result in Pacific Northwest plants losing their short-run operating cost advantage over the hypothetical Ohio Valley plant. The study goes on to say that, even if Pacific Northwest plants were to lose their electricity cost advantage over the Ohio Valley, it would still be profitable to maintain a number of Pacific Northwest plants to serve West Coast markets. A break-even position for the aluminum industry could be maintained at Pacific Northwest power rates between 9-12 mills/kWh for non-interruptible power (Reference 35, p. v-43). According to Ernst and Ernst, this would reduce the idle capacity requirement and retain the Pacific Northwest's competitive position vis-a-vis other domestic locations.

This alternative would not result in price increases any greater than those likely to be caused by producer's building power plants, relocating, or closing down Pacific Northwest production entirely. It would not involve the employment and financial impacts imposed upon the region and local areas. Though it would, in all probability, require the building of new thermal plants, it would allow the diffusion of the costs of generation by "average" versus "marginal" pricing across all sectors, avoiding the disruptive effects of penalizing the aluminum industry.

4.5 CONSERVATION, IMPLEMENTATION, TECHNOLOGICAL CHANGE AND DISTRIBUTIONAL IMPACT

4.5.1 Introduction

This section briefly analyzes the potential electric power savings in 1995 central station power that might occur in the Pacific Northwest under the Alternative Scenario conservation plan. Also considered are questions pertaining to the implementation of such a plan, the potential for new technology to supply electricity, and the distributional impact of a program of intense conservation.

4.5.2 Residential Sector Conservation Potential

BPA has projected that 1995 end-use demands for space heating, water heating, electrical appliances and lighting in the residential sector would total 97.45 x 10^9 kWh/yr. The Alternative Scenario estimates that the 1995 residential sector power demands will be only 50.66 x 10^9 kWh/yr. This figure was obtained by using the SOM study's projections (Reference 4) of savings made possible by a program of conservation. The projected savings are based on a series of conservation actions relating to the end-use demands for electric power.

Pacific Power and Light (PPL) undertook an analysis of the feasibility of the SOM projected conservation actions and the projected savings from the SOM conservation actions (Reference 40). PPL concluded that a large portion of the projected savings in electric power demand that SOM stated was possible could not be realized because the conservation actions had either already been implemented or the projected savings due to a particular conservation action were overestimated. Overall, PPL lowered the SOM estimated potential conservation savings (as per SOM Strategy 6) in the residential sector by 45% (Table 4.5-1).

TABLE 4.5-1

ESTIMATES OF REGIONAL ENERGY SAVINGS AND COST OF PROPOSED CONSERVATION ACTIONS IN RESIDENTIAL SECTOR (COST OF PROPOSED ACTIONS)

Conservation Action	SOM Estimate[1]	PPL Estimate[1]	PPL as Percent of SOM	New Single Family	Payback in Years	New Multi-Family	Payback in Years	Existing Single Family	Payback in Years	Existing Multi-Family	Payback in Years
Space heating actions	5,013	2,284	46	$ 65	1.2	$ 65	3.1	$103	1.1	$ 83	2.3
Installing insulation	4,541	4,541	100	$539	13.6	$171	14.0	$726	9.7	$180	8.4
Installing storm windows	3,602	3,326	92	$262	6.5	$101	6.6	$910	22.1	$338	22.3
Insulating water heater	1,925	1,337	69	$ 8	0.9	$ 8	0.9	$ 8	0.9	$ 8	0.3
Constricting water flow	4,461	1,561	35	$ 5	0.2	$ 5	0.3	$ 5	0.2	$ 5	0.3
Cold water washing	749	500	67								
Hot water applicance standards	5,175	2,588	50								
Electrical appliance standards	16,424	7,390	45								
Lighting savings	142	142	100								
Total	43,032	23,669	55	$879		$350		$1752		$350	

[1]Millions of kWh.

Source: Data on power estimates from Reference 40, p. 4. Data on costs (in 1976 dollars) and payback estimates from Reference 4, pp. 96-11.

Table 4.5-1 gives a detailed breakdown of the SOM estimated savings by conservation action and the PPL changes in the SOM savings. Table 4.5-1 also gives cost and payback information (from the SOM report) for the conservation actions associated with various residential housing types.

There is a possibility that the PPL estimates of potential conservation savings are still overestimated. This consideration is based on the fact that PPL did not adjust the SOM assumed adoption rates for the conservation actions. In reality, numerous economic, institutional and social barriers exist for the adoption of the proposed conservation actions in the residential sector. This is particularly true for capital intensive conservation improvements in existing housing stock. Table 4.5-2 lists the proposed conservation actions and some of the barriers to their adoption in the residential sector.

TABLE 4.5-2

BARRIERS TO ADOPTING PROPOSED CONSERVATION ACTION IN RESIDENTIAL SECTOR

Conservation Action by Residence Type	Inertia and Inconvenience	Lack of Cost-Benefit Information	Initial Capital Cost Too High	Insensitive to Electricity Costs	Financing Problems	Better Returns on Capital Alternative	Payback Period is Too Long	Uncertainty in Capital Cost Recovery	Cost Relative to Initial Investment	Property Tax Increase Feared	Federal Income Tax Aspects	Alternative Needs for Capital	Physical Retrofitting Difficulties
1. Existing Single/Multi-Family Residences													
Space heating actions	X	X	X	X	X	X	X	X	X	X	X	X	X
Installing insulation	X	X	X	X	X	X	X	X	X	X	X	X	X
Installing storm windows	X	X	X	X	X	X	X	X	X	X	X	X	X
Insulating water heaters	X	X			X	X	X				X	X	X
Constricting water flow	X	X		X									
Cold water washing	X												
Hot water appliances standards	X		X	X	X	X					X	X	X
Electrical appliance standards	X		X	X	X	X					X	X	X
Lighting savings	X			X									
2. New Single/Multi-Family Residences													
Space heating actions					X	X						X	
Installing insulation					X	X						X	
Installing storm windows					X	X						X	
Insulating water heaters					X	X						X	
Constricting water flow	X	X		X									
Cold water washing	X	X		X									
Hot water appliance standards				X	X	X							
Electric appliance standards				X	X	X							
Lighting savings	X			X									

4.5.2.1 Implementation of the Alternative Scenario Plan

The Alternative Scenario proposes a wide variety of regulations, educational and technical assistance programs, and financial incentives and assistance to implement the intense conservation scenario. In the form of regulation, energy conserving building codes for new construction and required compliance over time to the new code standards by old construction; performance design standards for industry; and energy efficiency standards for new appliances sold in the Pacific Northwest are proposed, based on the SOM report (Reference 4).

The Alternative Scenario independently proposes a wide variety of financial incentives including loans and tax credits to encourage the adoption of the conservation actions. Table 4.5-3 lists the proposed government and utility actions designed to encourage electric power conservation. Table 4.5-4 lists estimates of the possible costs of the proposed actions and incentives computed in this study.

TABLE 4.5-3

PROPOSED GOVERNMENT/UTILITY ACTIONS FOR IMPLEMENTING ALTERNATIVE SCENARIO PLAN

Proposed Actions	Residential		Commercial		Manufacturing	
	New Buildings	Existing Buildings	New Buildings	Existing Buildings	New Buildings	Existing Buildings
1. Regulation						
New energy-conserving building code for new construction	X		X		X	
Resale requirements for meeting new code standards		X				
Retrofitting by 1995 to new conservation standards				X		
Hot water appliance consumption standards -- new appliances	X	X	X	X	X	X
New appliance electrical efficiency standards	X	X	X	X	X	X
Information, education, and technical assistance	X	X	X	X	X	X
Performance standards design and plant approval					X	X
2. Incentives						
Five percent energy tax	X	X	X	X	X	X
Low interest loans		X		X		X
Tax exemptions		X		X		
Tax credits		X		X		
Grants		X		X		
Utilities install insulation/conservation measures		X		X		
Loans		X		X	X	

Source: For regulations, Reference 4, strategy 6, p. 46; for incentives, Reference 4, p. 46 and Reference 3, pp. 88-115.

TABLE 4.5-4

PARTICIPATION RATE AND COST OF PROPOSED ACTIONS

	Participation Rate	Estimated Cost
1. Educational and Technical Assistance (E&TA)		
Mailing a first class informative letter	To all households in Pacific Northwest	$500,000 per mailing
Spending $10 per dwelling unit on an E&TA program	All dwelling units in Pacific Northwest	$22,780,000
Spending $10 per capita on an E&TA program	Total population in Pacific Northwest	$68,780,000
Spending $20 per dwelling unit on an E&TA program	All dwelling units in Pacific Northwest	$45,780,000
2. Tax Credits		
$100 credit for homeowners installing insulation	50% of existing single family homes in Pacific Northwest	$84,000,000
$100 credit per dwelling unit	50% of dwelling units in Pacific Northwest	$114,450,000
3. Low Interest Loans/Capital Costs		
$1500 home insulation loan	40% of single family homes	$1,008,000,000
$1500 home insulation loan	40% of dwelling units	$1,373,400,000

Regulations such as the new building codes and new appliance standards are easily enforced through existing institutional structures, and compliance can be expected. Those actions that run counter to an individual's financial self-interest (such as retrofitting conservation actions on decaying houses) can be expected to meet resistance in implementation. Therefore, while all of the proposed regulations and incentives may eventually be effective, it may take a longer time than expected in the Alternative Scenario.

4.5.3 Commercial Sector

The Alternative Scenario projected central station prower demands for the commercial sector at 18.5 x 10^9 kWh/yr in 1995, which is only one-third of the BPA estimate of 52.66 x 10^9 kWh/yr. The Alternative Scenario projection is based on the implementation of conservation actions in end-uses in the many diverse buildings and institutions that constitute the commercial sectors.

No equivalent of the PPL study of residential sector conservation analysis was found to exist for the commercial sector. Consequently, it was not possible to state if the estimates of potential savings are overestimated.

However, barriers to the adoption of the proposed NRDC/SOM actions exist. Table 4.5-5 presents a listing of some of the economic and institutional barriers to the adoption of the proposed energy conservation actions in the commercial sector. From the listings in Table 4.5-5, it appears possible to state that barriers exist in the commercial sector that may act to prevent the total projected Alternative Scenario conservation savings in power use to occur by 1995.

Implementation in the commercial sector would take the form of building code energy requirements for new buildings, requiring conservation retrofitting actions by 1995 in existing buildings, and educational, technical, and financial incentive programs. It is expected that conservation actions that run counter to an individual's financial self-interest, particularly in the case of retrofitting older buildings, will be strongly resisted.

4.5.4 Agricultural and Industrial Sectors

The Alternative Scenario and BPA project the following power needs in these sectors in 1995 (Reference 3), in 10^9 kWh/yr:

	ALTERNATIVE SCENARIO	BPA
Agriculture Sector	7.3	9.8
Manufacturing Sector	38	129.6

TABLE 4.5-5

BARRIERS TO ADOPTING PROPOSED CONSERVATION ACTIONS IN COMMERCIAL SECTOR

Conservation Action	Inertia and Inconvenience	Lack of Cost-Benefit Information	Initial Capital Cost Too High	Insensitive to Electricity Costs	Financing Problems	Better Return on Alternative Capital Improvements	Payback Period is Too Long	Uncertainty in Capital Cost Recovery	Cost Relative to Initial Investment	Property Tax Increase Feared	Federal Income Tax Aspects	Alternative Needs for Capital	Physical Retrofitting Difficulties
1. Existing Buildings													
<u>Large office buildings</u>													
Install equipment, controls	X	X	X	X	X	X	X	X	X	X	X	X	X
Modify H/C system	X	X	X	X	X	X	X	X	X	X	X	X	X
Insulate windows	X	X	X	X	X	X	X	X	X	X	X	X	X
Insulate walls	X	X	X	X	X	X	X	X	X	X	X	X	X
<u>Small offices</u>													
Install thermostat	X	X	X	X	X	X	X	X	X	X	X	X	X
Install heat pump	X	X	X	X	X	X	X	X	X	X	X	X	X
Insulate windows	X	X	X	X	X	X	X	X	X	X	X	X	X
<u>Retail buildings</u>													
Air ventilation	X	X	X	X	X	X	X	X	X	X	X	X	X
Modify HAVC unit	X	X	X	X	X	X	X	X	X	X	X	X	X
Insulate windows	X	X	X	X	X	X	X	X	X	X	X	X	X
Insulate walls	X	X	X	X	X	X	X	X	X	X	X	X	X
2. New Buildings													
<u>Large offices</u>													
Install equipment, controls					X	X							
Install chiller and N/R					X	X							
Air control					X	X							
Tinted glass					X	X							
<u>Small offices</u>													
Automatic night thermostat					X	X							
Insulate walls, etc.					X	X							
Install heat pump					X	X							
<u>Retail buildings</u>													
Heat recovery					X	X							
Double glaze windows					X	X							
Reduce glass area					X	X							

The agricultural power demand is mostly power for irrigation pumps. Projected power need differences are a function of different projections of the amount of land to be under irrigation in the Pacific Northwest.

The Alternative Scenario figures for industrial power demand and savings are based on the following assumptions:

- Electricity will substitute for fossil energy at the rate of 0.6 percent a year;
- Electricity will substitute for labor at a linear rate of 1 percent per year;
- Conservation will reduce electrical energy requirements by 4 percent in 1985 and 20 percent in 1995; and
- On-site generation will produce a little less than 2 percent of the 1995 conservation savings.

No data have been obtained that specifically confirm or deny the Alternative Scenario assumptions as to the potential for conservation in the manufacturing sector. Projected rising real electric power prices will give incentives to industry to conserve. However, the potential for electric power conservation in manufacturing tends to be industry specific. This is also true for individual firms within an industry. Hence, only a detailed analysis of the industrial sector of the Pacific Northwest can provide insight into the accuracy of the Alternate Scenario projections for industrial sector power conservation.

4.5.5 Adoption of the New Energy Technologies

Reference 3 discusses the use of solar, co-generation and total energy systems, wind-power, burning waste products, and geothermal energy as potential new sources of electric power in the Pacific Northwest in the post-1995 period. Certain barriers need to be overcome before any of these new technologies will be a significant force in the supply equation of electrical energy in the Pacific Northwest:

- Successful technological innovation in a field tends to come from demand pull within a field, rather than technological push. This means that the economics of electric power from these new technologies will have to be competitive with alternative power sources in the Pacific Northwest.

- The current technological state of some of the new technologies such as solar and wind power is in the product technology and development stage and requires large commitments of capital to bring the new means of power production to widespread use.

- Institutional barriers, including legal, social, and informational problems, must be overcome before widespread adoption of these new technologies can occur.

The Alternative Scenario states that solar-powered sources would be employed for space and water heating respectively in 6% and 20% of the new homes built between 1975 and 1995. On a national level, ERDA is predicting 10% of housing starts to have some form of solar power in 1985, which includes the many areas that are much better suited (i.e., sunnier) for solar power than the Pacific Northwest.

Adoption of other new technologies that are not as well developed as solar power in the time period before 1995 seems doubtful. Even if sufficient demand developed, it would be doubtful if many of the institutional barriers could be quickly overcome. Any estimates of the future power sources to come from a currently non-conventional source (i.e., wind, co-generation) is to be viewed very cautiously.

4.5.6 Distributional Impacts

Any program of energy conservation will have distributional consequences. A few of the distributional issues related to the Alternative Scenario are noted below:

- Any plan that involves higher electricity prices to residential users will impact low income groups more than affluent households. This occurs for two reasons: low income persons have fewer discretionary uses of electricity than upper income persons and utility costs are a greater part of low income households budget. While more affluent persons consume more power, they will be less impacted in their lifestyle by price increases, at least in the short run.

- A plan of regulation and standards requirements acts to boost costs and thus has distributional impacts. Costs for such items as rents and appliances may go up due to conservation regulations. The impact of such increased costs on income groups depends upon their consumption patterns and relative importance of the items impacted by the price increases to the various income groups.

- A plan of conservation instead of expansion of utility thermal power plants will act to redistribute property tax base away from the communities that would have benefited by the construction of the utility plant to the cities and suburbs where the value of property will be increased by conservation improvements.

- Any plans of a utility installing free insulation, tax incentives, low interest loans to pay for the cost of conservation improvements, etc., will have major distributional consequences. The exact impact of the program will depend upon how it is structured, but any type of government/utility economic incentive must be carefully planned for both maximum efficiency and for the desired income distribution consequences.

4.6 CAPITAL CONSIDERATIONS

4.6.1 Introduction

The analysis that follows addresses the impact of capital constraints on implementation of the Power Plant and Alternative Scenarios. While the scope of this analysis and the intricacy of the topic preclude comprehensive statements, the analysis does indicate relevant trends and variables that will affect the capital input to scenario implementation.

Capital markets determine the direction and level of an economy's activity to some extent. An understanding of the workings of this market will enable more accurate forecasts of the future economy. The material that follows is an attempt to isolate several capital-related phenomena and present some insight into their ramifications for the two scenarios.

The analysis is divided into two sections. The first section considers capital constraints impacting the Power Plant Scenario, including investor information, rate of return, and capital supply. The second section considers the Alternative Scenario in light of several capital-related phenomena and suggests several areas for concern with regard to scenario implementation.

4.6.2 Capital Constraints and the Power Plant Scenario

This scenario forecasts expansion in 15 of the 16 manufacturing sectors listed in Table 4.2-1. To facilitate this expansion, the scenario requires the construction of power facilities. These two aspects of the scenario can be brought to fruition only if the investment capital is available for expansion and replacement of existing plant, equipment, etc. Investment capital is made available through a variety of financial intermediaries. Access to the available capital through intermediaries for Pacific Northwest projects will be a function of: (1) investor's information about the projects; (2) the project's rate of return as perceived by the investor; and (3) the supply of investment capital. Each aspect is discussed below.

4.6.2.1 Investor Information

For capital to be made available to a given investment project, investors must be aware of a project's existence. This awareness can become clouded when spatial and institutional arrangements separate capital demanded from capital supplied. To the extent that capital projects occasioned by the scenario are marketed in national arenas, the information impediment is mitigated. Trading in national markets would generally seem to be an eventuality for investment projects in this scenario as these projects are corporate in nature, arising as they do in the manufacturing and utilities sectors of the economy. In this regard, Straszheim indicates that "Corporate stocks and bonds and government securities are all traded in national markets, with essentially equal access" (Reference 41). Therefore, information about the demand for capital in the Pacific Northwest under this scenario would not seem to preclude the availability of capital for these projects.

4.6.2.2 Rate of Return

In a money market constrained by limited capital, investors will rationally assign their investment funds to the most lucrative investment alternatives. To achieve maximum efficiency from their capital, investors will give priority to those investment opportunities which offer the highest rates of return. In assessing the rate of return likely to be associated with the expansion attributed to the industrial and utilities sectors under the BPA scenario, investors need to assay how well the planned expansion matches likely demand.

It has been suggested in other sections of this report that BPA's estimates of future power requirements in the manufacturing sector seemed high, possibly due to the nature of the BPA method for forecasting electricity demand. To the extent that BPA's forecasts may overstate demand, increasing output capabilities will yield excess capacity and low return on investment. These considerations indicate that investors would be hesitant to make funds available for all the projects implied in the Power Plant Scenario.

4.6.2.3 The Supply of Loanable Funds

It was stated above that the capital projects implied in the Power Plant Scenario would probably be financed in national money markets. It is appropriate, then, to address the issue of whether capital will be in sufficient supply nationally to finance the projects required by this scenario. To determine the likelihood of capital availability, it is necessary to define a capital shortage. Upon defining the phenomena, it is then appropriate to search for manifestations of the definition's tenets. This procedure follows below.

A capital shortage is defined by Brenner as "double-digit long-term interest rates, rising debt-equity ratios and declining cash flow-capital expenditure Ratios" (Reference 42). The latter part of this definition shows some evidence of developing as evidenced by the data in Table 4.6-1 (Reference 42). Columns 5 and 6 of this table indicate a rather steady decline in the "Internal Liquidity Ratios" derived by each of the alternative methodologies. These data indicate that a declining cash flow-capital expenditure ratio can be anticipated to 1984 and that at least one symptom of a capital shortage is developing. The implication of the capital requirements attendant to BPA's growth scenario is that some projects will not obtain the required capital and therefore will not occur.

A study by the Stanford Research Institute indicates that capital shortages will not be a problem for BPA utilities (Reference 43). If this is true and if the development of a national credit squeeze as forecast

TABLE 4.6-1

INTERNAL LIQUIDITY RATIOS

	(1) Fixed Business Investment	(2) Nonfarm Inventory Investment	(3) Retained Earnings & Deprec.	(4) Inv. Val. Adj.	(5) Internal Liquidity[a] Ratio (IVA)	(6) Internal Liquidity[b] Ratio (II)
1947	23.4	1.3	19.7	-5.9	0.716	0.644
1948	26.9	3.0	22.6	-2.2	0.799	0.704
1949	25.1	-2.2	19.2	1.9	0.803	0.914
1950	27.9	6.0	24.8	-5.0	0.799	0.638
1951	31.8	9.1	23.3	-1.2	0.714	0.553
1952	31.6	2.1	22.5	1.0	0.728	0.688
1953	34.2	1.1	24.7	-1.0	0.708	0.680
1954	33.6	-2.1	26.3	-0.3	0.778	0.827
1955	38.1	5.5	33.9	-1.7	0.867	0.748
1956	43.7	5.1	34.8	-2.7	0.765	0.676
1957	46.4	0.8	35.0	-1.5	0.738	0.719
1958	41.6	-2.3	32.8	-0.3	0.785	0.828
1959	45.1	4.8	39.4	-0.5	0.868	0.782
1960	48.4	3.3	38.1	0.2	0.789	0.740
1961	47.0	1.7	39.7	-0.1	0.843	0.814
1962	51.7	5.3	46.1	0.3	0.895	0.813
1963	54.3	5.1	48.4	-0.5	0.887	0.808
1964	61.1	6.4	54.5	-0.5	0.888	0.801
1965	71.3	8.6	63.1	-1.7	0.873	0.773
1966	81.6	15.0	68.6	-1.8	0.830	0.697
1967	83.3	7.5	68.3	-1.1	0.813	0.743
1968	88.8	6.9	71.0	-3.3	0.781	0.717
1969	98.5	7.7	72.4	-5.1	0.709	0.650
1970	100.6	4.3	70.6	-4.8	0.678	0.644
1971	104.4	4.9	82.9	-4.9	0.771	0.726
1972	118.2	7.8	94.2	-6.9	0.776	0.716
1973	136.2	11.4	114.0	-17.3	0.773	0.691
1974	149.2	11.9	129.1	-35.1	0.748	0.658
1975	147.9	-17.7	121.5	-11.4	0.783	0.858
1976	174.1	9.2	147.1	-13.7	0.806	0.747
1977	201.7	20.1	165.2	-18.1	0.774	0.689
1978	215.9	8.6	161.4	-17.1	0.708	0.668
1979	220.6	2.7	167.7	-14.4	0.728	0.706
1980	243.0	14.8	192.1	-16.4	0.757	0.701
1981	274.6	21.9	213.0	-14.7	0.749	0.684
1982	312.2	25.7	230.5	-14.4	0.715	0.654
1983	351.7	28.3	250.5	-16.6	0.689	0.632
1984	390.7	29.8	275.4	-21.5	0.677	0.623

[a] $[(3) + 1/2(4)] \div 1$

[b] $(3) \div [(1) + (2) - (4)]$

by Brenner, Evans, et al (Reference 42) is assumed, then the manufacturing sector will be impacted by the tight credit market. If this latter sector cannot obtain credit for expansion and/or replacement investment, its output will contract. If output in the manufacturing sector contracts (or at least does not expand), BPA's estimation of future electrical generation requirements needs to be reevaluated.

To summarize, national capital market experts are forecasting a tight credit market over the next ten years. Assuming that all regions feel the effect of the tightness equally, the Pacific Northwest can expect that some investment projects will experience insufficient funding. The sectors that will feel the effect of credit unavailability most dramatically can only be revealed by an in-depth regional analysis.

4.6.3 Capital Constraints and the Alternative Scenario

The Alternative Scenario calls for expansion in 14 of 16 industrial sectors. The expansion is selective and ostensibly does not require much investment spending in the utilities sector. However, it does presume expensive investment in conservation actions in the manufacturing, commercial, and residential sectors which may offset the utilities spending required by the Power Plant Scenario. The Alternative Scenario calls for a total expansion of the industrial sector equal to that forecast by BPA. As a result, the implementation of the Alternative Scenario will also be susceptible to national capital market constraints similar to those discussed in regard to the Power Plant Scenario above.

In order to specify precisely the extent of the two scenarios, further detailed regional and sectoral analysis would be required. However, there is evidence available which indicates that at least segments of the residential sector may face capital constraints in attempting to meet the conservation actions required by the Alternative Scenario.

For households to implement many of the conservation initiatives suggested by the Alternative Scenario, they will need to demand capital. Normal household credit channels are small and medium size commercial banks. Straszheim suggests that there can be significant regional credit cost differentials in the small and medium size commercial bank credit markets resulting from institutional arrangements preventing these banks from tapping into national credit streams (Reference 41). These differences result in certain banking areas facing capital account shortcomings and manifest themselves to the consumer in the form of high interest rates. The ability of a local banking area to meet loan demands is a function of the savings habits and income of the area's residents, as well as prevailing interest rates. If regional income decreases, the volume of credit available at local commercial banks through resident savings would be expected to decrease and the price of that credit (i.e., the interest rate) would be expected to rise, perhaps to the point where some consumers are priced out of that market.

The above set of phenomena can be expected to occur, at least in the short run, in areas where the Alternative Scenario recommends aluminum industry phase-out. For example, it was earlier indicated that in Chelan County, Washington, a large portion of the county labor force will be unemployed if the aluminum plant there closes. It was also pointed out that average earnings in the aluminum industry are considerably higher than in other industries. Closing the aluminum plant in Chelan County would decrease county income considerably. If it is assumed that county residents deposit their savings in local commercial banks, the lending ability of these intitutions would be contracted due to the phase-out and consumer requests for loans for conservation actions would go unfilled. Again, this is a hypothesis centering on a specific set of circumstances. As such, the magnitude and probability of such a development remains unresolved. However, this situation is indicative of the kinds of phenomena that may arise under the Alternative Scenario.

The Alternative Scenario posits considerable public intervention as input to such processes as labor training, conservation initiative, etc. The analysis presented above suggests that private mechanisms for motivating these economic processes will face some difficulty. It appears then that the capability of the public sector to manipulate these processes to achieve the desired results will be severely tested.

5.0 IMPACT OF NEW NATIONAL ENERGY POLICY

During the period this study was being conducted, a new National Energy Plan (NEP) was announced by President Carter (April 20, 1977). As the cornerstone of the new energy policy concerned energy conservation, it was decided to conduct a detailed examination to assess how the implementation of the new energy policy--including its energy supply components where appropriate--would affect the previous results, particularly with regard to any changes in the differences between the Power Plant and the Alternative Scenarios.

Many of the specifics of the new energy policy have yet to be fully defined. Therefore, only those policy measures which were felt could have the greatest impact and which also could be quantified within the economic analysis framework already developed were examined in detail. These quantifiable impacts fell into three general categories around which this section is organized:

- Impacts on electrical energy consumption
- Impacts on the capital costs of implementing conservation
- Impacts on fuel prices

All three categories are discussed in terms of how they affect the results in both the Power Plant and the Alternative Scenarios and hence the differences between them. The net impact on the difference in total costs between the two scenarios is also assessed. Other policy measures which could not be quantified within the general framework developed here but which probably have a definite impact on the scenarios have been dealt with qualitatively.

A general comparison of the National Energy Policy with the Alternative Scenario in terms of its suggested levels of conservation implementation and its proposed tax credits and other financial incentives is provided in Table 5.0-1. Note that the NEP's proposed levels of implementation are generally higher than the corresponding levels in the Alternative Scenario

TABLE 5.0-1

COMPARISON OF NATIONAL ENERGY PLAN (NEP) CONSERVATION MEASURES WITH ALTERNATIVE SCENARIO

SECTOR	END-USE SERVICE(S)	CONSERVATION MEASURES	NRDC[1] 1985[2] Implementation % (Electric Buildings)	NEP 1985 Measures Implementation %	NEP 1985 Measures Tax Credits (& other incentives)
RESIDENTIAL	Space Heating	Lower thermostat 68-70° day, 62° night; automatic thermostat night setback; weather-strip homes	35% - 37%	*	25% of first $800; 15% of next $1,400
		Insulate ceilings, walls, floors	46% - 50%	90%	
		Retrofit storm windows on existing and new dwellings	42% - 49%	*	
				*	
		Heat pumps	.4% - 3%	*	
		Solar Space Heating Systems	.4% - 1.9%	.3%[3]	Solar: Starts at 40% of first $1,000; 25% of next $6,400 in 1977. Declines to 25% of first $1,000; 15% of next $6,400 by 1985.
		Total energy systems	.4% - 1.8%	*	
	Water Heating, Lighting, Appliances	More efficient appliances (water heating, lighting, other).	100% (All Homes)	Mandatory std. for all new appliances.	
		Solar water heaters	2% (All Homes)	2.7%	
COMMERCIAL	Space Heating	Lower temperature to 72° in winter; raise to 78° in summer.	30% - 73%	90% in general; 100% for Federal Buildings	10% Investment tax credit
		Reduce window glass area. Insulate.	30% - 73%		
		Semiautomatic night setback of thermostat.	57% - 73%		
		Packaged heat pumps in small office buildings	43% - 78%		
		Central heating and cooling systems; heat recovery from refrigeration compressors and water chilling.	43% - 73%		
		Solar heating	1%		
		Total energy systems	2%	*	
	Water Heating	Reduce water heating temperature	30% - 73%	*	
	Lighting	Reduce lighting levels but maintain 80-100 ft.-candles on work surfaces	30% - 73%	*	
MANUFACTURING	Production Processes	Reduction in energy intensity by 4% in 1985	100%	*	10% Investment Tax Credit Plus Fair Utility Rates for surplus & backup power from cogeneration.
		On-site electrical generation thru self-generation or utilizing production process waste.	20% (Lumber)	*	
			60% (Paper)	*	
			10% (Petroleum)	*	
AGRICULTURE	Irrigation	Use of wind-hydraulic and solar driven pumps.	1%	*	10% Investment Tax Credit

*Implementation levels unspecified.

[1] Natural Resources Defense Council, "Choosing an Electrical Energy Future for the Pacific Northwest: An Alternative Scenario," Final Draft, January 31, 1977.

[2] Skidmore, Owings and Merritt, "Bonneville Power Administration Electric Energy Conservation Study," June. 1976.

[3] Based on requirement for 2.5 million water heaters and .25 million space heaters by 1985. SEIA background report to NEP.

for 1985 despite the fact that the NEP is based largely upon incentives while the Alternative Scenario is based upon a mandatory implementation strategy.

The remaining conservation measures where no implementation levels were specified in the NEP should not be interpreted as being omitted from consideration by the NEP, but only as having no specified implementation levels.

5.1 IMPACT ON ELECTRICAL ENERGY CONSUMPTION

The National Energy Plan calls for strong reliance upon conservation measures in all sectors of the economy. The measures include those which are mandatory, as well as those which are voluntary. Three specific NEP policies were identified as having definite bearing on the current study. These are the following:

- Implementation of insulation in residential buildings (incentive).
- Implementation of solar space and water heating units in residential and commercial buildings (incentive).
- Mandatory building efficiency standards (mandatory).

While all of these items were assessed for their potential impact in both scenarios, only the implementation of insulation was determined to have an actual effect on them.

It should be emphasized here that since the Alternative Scenario is concerned with homes that are electrically heated, the impact of the NEP implementation is determined relative to these homes only. Consequently, this study does not reflect NEP effects on fossil fuel consumption.

5.1.1 Implementation of Insulation in the Residential Sector

The National Energy Plan has the insulating of 90%[1] of all residences and other buildings by 1985 as one of its goals. The primary impact of this goal is to accelerate the implementation of insulation in the residential sector. Consequently, both the Power Plant Scenario and the Alternative Scenario assumptions were modified to include this feature. These modified

[1] As this report was going to press, there were indications that the 90% penetration goal might be reduced to 60%.

scenarios will be referred to as excursion cases, and the non-modified scenarios referred to as base cases hereafter. For the Power Plant Scenario, the NEP initiatives represent the only conservation effort to be implemented since the general pattern of this scenario does not include conservation within its structure.

The percent of electrically heated residences insulated by 1985 was set equal to 90% in all cases for both scenarios. From 1985 through 1995, the level of implementation of insulation was held constant at 90% for the Power Plant Scenario, but allowed to rise to the previous 1995 levels in the Alternative Scenario.[1] Since the procedures for implementing this measure in the two scenarios were somewhat different, they will be discussed separately.

In the case of the Alternative Scenario, the change in the implementation level of insulation required that the thermal performance coefficients (TPCs) for each electrically heated dwelling type in 1985 be recalculated. It will be recalled that the procedure for calculating the TPCs as explained in Section 2.2 was to multiply the percent implementation of a given measure in a given year by the number of electric homes of a given type in that year and then, based on the annual kWh_e savings per home from that measure, determine the total sector savings. When this is done for each conservation measure in each given dwelling type and the result summed, the total sector savings is determined. By dividing the total savings by the total before conservation consumption, the fractional sector savings is obtained. This fractional savings subtracted from unity is defined as the average TPC for that type of dwelling.

When this procedure was performed for insulation by changing the 1985 level to 90% while retaining the previous levels of all the remaining passive measures, the following results were obtained:

[1] In the case where the housing stock declined after 1985, i.e., MF<76, 1985 was the cut-off date for installation of insulation.

TABLE 5.1-14

COMPARISON OF TPCs IN ALTERNATIVE SCENARIO
BASE AND EXCURSION CASES
(Electrically Heated Homes)

	1985 Base Case	1985 Excursion Case	1995 Base Case
SF<76	.737	.636	.473
SF>76	.769	.706	.538
MF<76	.771	.689	.542
MF>76	.785	.734	.569

It can be seen from the above table that while the implementation of this level of insulation improved the average TPCs of all electrically heated dwelling types over their 1985 base case level, it did not improve them to their 1995 levels. These TPCs were then assumed to change linearly from unity in 1975 to their 1985 excursion case levels and from there linearly to their previous 1995 levels. When substituted for the base case TPCs these excursion case TPCs provided a reduced level of energy consumption for space heating in the residential sector.

In the Power Plant Scenario excursion case, data from the SOM Study (Reference 4) were used to determine the residential sector energy consumption profile following the NEP recommended level of insulation. Since pertinent data were given only for the years 1980 and 1995, the projection is based on calculations for these years only.

A comparison of the residential sector energy consumption in the base and excursion cases in both scenarios is plotted in Figure 5.1-1. It is obvious from this figure that the implementation of the NEP level of insulation makes a greater difference in the electrical energy consumption of the Power Plant Scenario than in the Alternative Scenario. The cost savings effect will exaggerate the difference in the two scenarios even more due to differences in the prices of electricity at which this energy is being saved. This is a consequence of the substantial level of implementation of insulation measures already considered in the base case Alternative Scenario in contrast to much lower levels of insulation implementation in the base case Power Plant Scenario.

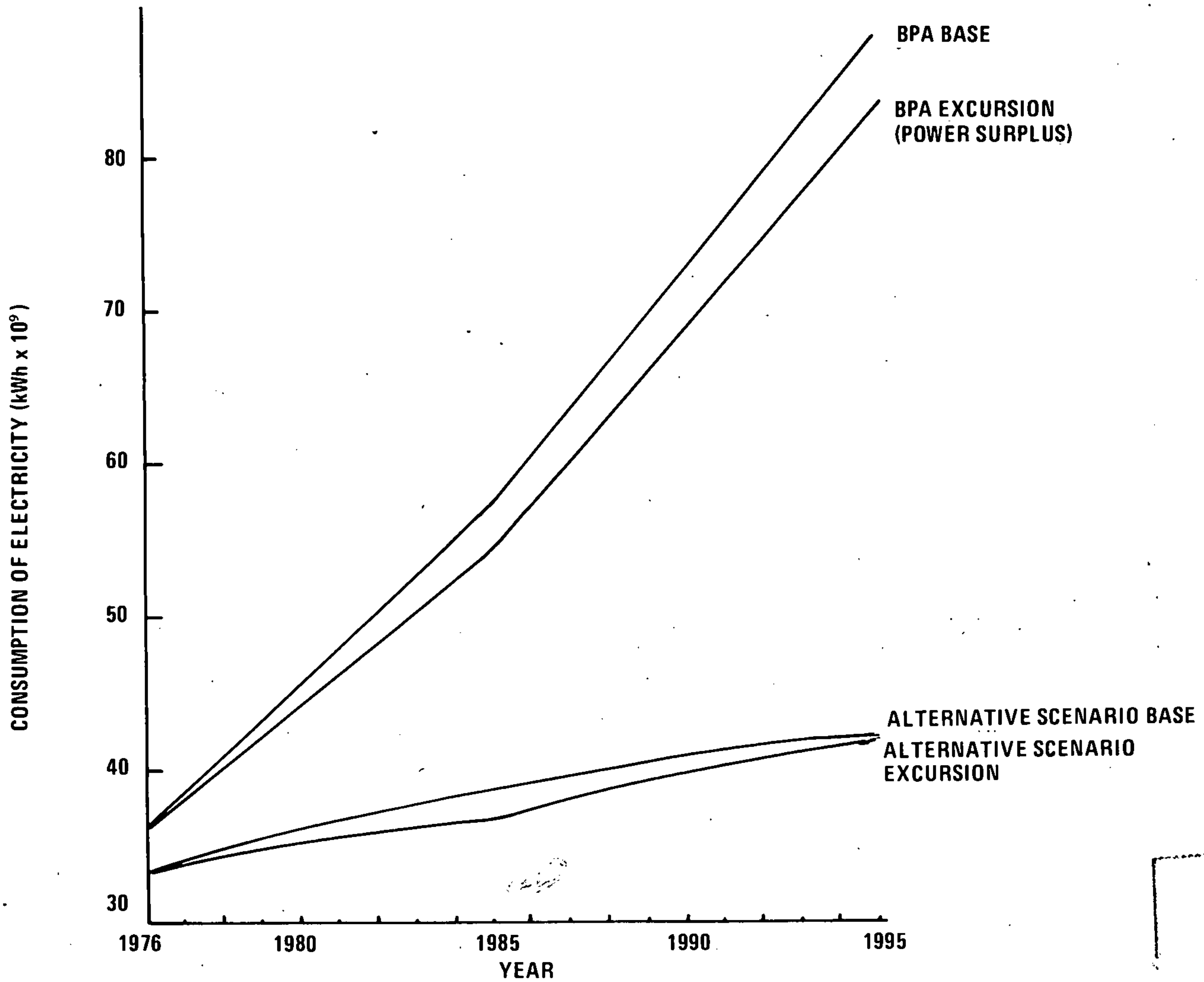


FIGURE 5.1-1. RESIDENTIAL CONSUMPTION

The cumulative savings over the 20-year period resulting from the implementation of the NEP recommended level of insulation is 18.2×10^9 kWh in the Alternative Scenario. The maximum annual difference in this scenario occurs in 1985 and is 1.7×10^9 kWh. The cumulative savings is 84×10^9 kWh in the Power Plant Scenario, with a maximum annual difference of 4.4×10^9 kWh occurring in 1995. These maximum annual differences correspond to 195 average MW_e in the Alternative Scenario and 500 average MW_e in the Power Plant Scenario (which equates to roughly one 750 MW_e power plant, assuming a .67 capacity factor). The savings may, of course, be viewed as a power reserve rather than a reduction in the number of power plants required.

5.1.2 Solar Heating Implementation

The goal of the solar heating program of the NEP is to have over 2.5 million installations in residential units by 1985. This goal is very close to that projected by the Solar Energy Industries Association (Reference 17) with the same incentives. Currently there are 74 million residential units in the United States (Reference 18, p. 40). Based on an expected 1.3 million new housing starts per year over the next decade (Reference 22, p. 8), this would result in approximately 83 million residential units by 1985. Equipping 2.5 million of these units with solar heating systems (NEP goal) would represent 3% of all residential units. Assuming a 90%/10% split between solar water heating and space heating as approximately indicated on Table 5.1-3, a 2.7% implementation level results for water heating and

TABLE 5.1-3

EFFECTS OF NATIONAL ENERGY PLAN[1] ON RESIDENTIAL SOLAR HEATING IMPLEMENTATION[2]

Year	Total Number of Water Heaters (Thousands)			Total Number of Combined Water and Space Heaters (Thousands)			Proportion Of Water Heaters and Space Heaters
	New Units	Retrofit Units	Total Units	New Units	Retrofit Units	Total Units	
1980	64	183	247	7.0	1.8	8.8	96%/4%
1985	392	1560	1952	216	70.2	286.2	85%/15%
1990	1071	3030	4110	783	1660	2443	59%/41%

[1]Assumes adoption of solar incentives identical to those in the NEP.
[2]Reference 17.

a 0.3% level for space heating. This compares with the Alternative Scenario assumptions of 2% space heating in new single-family homes and 1% in new multifamily residences in 1985, or .3% of all residences in the region. Thus the national average figures imply an equal implementation of solar space heating systems compared to the Alternative Scenario. However, for solar water heating, the implicit NEP target of 2.7% is somewhat higher than the 2% level assumed in the Alternative Scenario.

Of primary interest, however, is the fraction of the 2.5 million residences expected to have solar heating in 1985 that will be located in the PNW region. According to the Executive Director of the Solar Energy Industries Association, few of these installations will occur in the PNW region, even with incentives, due to current low prices of electricity and not too favorable sunlight conditions there (Reference 23). This opinion was confirmed in the analysis of solar heating in both the residential and commercial sectors conducted in this study, wherein solar heating showed a net cost to consumers in all cases. Therefore, it was decided not to increase the implementation level of solar water heating beyond the level already assumed in the Alternative Scenario.

While there would be no impact on the Alternative Scenario from solar heating implementation, there would be an impact on costs due to the tax credit provision in the NEP. This impact is discussed in subsection 5.2.2.

5.1.3 Mandatory Building Efficiency Standards

The NEP calls for advancing the effective date of the mandatory efficiency standards for new buildings required by the Energy Policy and Conservation Act from 1981 to 1980. Unfortunately, those standards have not yet been defined in detail so that a comparison with the efficiencies stated in the Alternative Scenario for commercial buildings cannot be made at this time.

However, for federal buildings, specifically, the NEP standards have been defined. The objective is to reduce by 1985 the energy intensity of existing federal buildings by 20% and that of new federal buildings by 45% relative to 1975 levels. While the exact proportion of federal buildings in the PNW was not known, the large office building prototype (10,000 ft^2 floor area) may be assumed to be representative of this type. Based on the data presented in Table 2.3-1 of subsection 2.3.2.1, it can be seen that the average energy savings for this type of building is 37.2% for both new and old structures combined. This is well within the rate of 20%-40% specified in the NEP and so it is likely that the NEP goal would have no impact on the energy savings for this type of building in the Alternative Scenario.

Whether the above statement can be generalized to include all the building types in the Alternative Scenario cannot be determined prior to publication of the mandatory building efficiency standards.

As was the case for solar heating systems, the effect of tax credits for investments in the building conservation technology assumed in the Alternative Scenario will be assessed in the next subsection.

5.2 IMPACTS OF IMPLEMENTING CONSERVATION ON THE CAPITAL COSTS

5.2.1 Tax Credits for Passive Conservation Measures in the Residential Sector

The national energy program provides for a tax credit of 25% of the first $800 and 15% of the next $1400 of the cost of passive conservation measures implemented between April 20, 1977 and December 31, 1984. In the case of the Alternative Scenario, these tax credits were computed for individual electrically heated residences based on the total initial (unfinanced) capital cost outlay for each[1] of the passive measures incurred in each residence type. The implementation levels of all the passive measures except insulation were left unchanged from those specified in the Alternative Scenario. The implementation rate of insulation was increased to conform to the national energy program goal of 90% by 1985. Following this procedure and knowing the stock of homes in which the conservation measures are implemented each year from 1977 to 1984, the total tax credit for this sector was determined for these years. The credits were then reflected in the cost accounts starting in the year 1978 and ending in the year 1985. A similar procedure was used for computing the tax credits in the Power Plant Scenario as well, but with insulation considered as the only conservation measure of relevance in that scenario.

[1] This procedure was followed since the distribution of consumers who install more than one conservation measure at a time was not known.

The results of implementing the passive conservation part of the national energy program guidelines in both scenarios, determined on the basis of the 20-year costs to the consumers, are shown in Table 5.2-1. Note that relative to the Alternative Scenario, the costs shown in Table 5.2-1 reflect the situation prior to the implementation of any of the active conservation measures. Consequently, the residential sector costs shown in this section will be different from those discussed in

TABLE 5.2-1

IMPACT OF THE NEP ON THE COST COMPARISON OF THE TWO SCENARIOS IN THE RESIDENTIAL SECTOR

Building Type	Twenty-Year Cost Totals ($ x 10^9 in 1976 $)		
	Base Case	Excursion Case	Net Savings In Excursion Case
Alternative Scenario (with Passive Measures only)			
Existing Single Family	3.573	3.306	0.267
New Single Family	1.927	1.864	0.063
Existing Multifamily	1.228	1.157	0.071
New Multifamily	.777	.756	0.021
Total Sector	7.505	7.083	0.422
Power Plant Scenario			
Total Sector	26.461	25.927	0.534

Section 5.4, where the Alternative Scenario was considered in totality (i.e., with both passive and active measures implemented). In contrast, the costs for the Power Plant Scenario are complete, since no active measure implementations were assumed.

The results indicate that there is a net cost savings of over $400 million in both scenarios following the implementation of the national energy program. While the savings in the two scenarios are comparable, it must be recalled that the Alternative Scenario is both less energy intensive (due to built-in conservation) and less cost intensive than the Power Plant Scenario. Consequently, while the magnitude of net savings is slightly lower in the Alternative Scenario, it represents a greater percentage of the costs incurred in the base case. Despite the fact that the tax credits were applied to all passive conservation measures in the residential sector of the Alternative Scenario, but only to a single conservation measure (i.e., insulation) in the Power Plant Scenario, the cost savings were greater in the latter case.

5.2.2 Tax Credits for Passive Conservation Measures in the Commercial Sector

According to the NEP (Reference 18, p. 42), "businesses would be entitled to a 10% tax credit for investments in approved conservation measures, in addition to the existing investment tax credits." As the list of approved measures was not included in the NEP, this statement was interpreted to apply to all the passive conservation measures that were costed in Section 3.5 for the Alternative Scenario. Since the minimum Federal efficiency standards for buildings have not yet been set, it was not possible to judge which conservation measures and what level of implementation would be required so that no comparable assessment could be made for the commercial sector of the Power Plant Scenario.

The manner of implementing this portion of the NEP policy is defined as follows. Referring to Table 3.6-1, the third column entitled "1980 SOM Regional Cost" displays the total unamortized capital costs of implementing conservation through 1980 by building type. The tax credits for these measures were computed by first dividing the 1980 cost by 5 in order to obtain the annual cost from 1976-1980, and then multiplying this annual number by 10% to obtainethe annual tax credit. The computed tax credit figure is shown in column 3 of Table 5.2-1 by multiplying this annual tax credit by four. The total tax credit applicable in the four allowable years of this period, 1977-1980, was determined, as shown under the column labeled (e). Then the procedure implemented previously in section 3.6 was applied taking into account the total allowable tax credits. This procedure and the results are presented in columns labeled (a)-(i) in Table 5.2-2. In this way, total Alternative Scenario costs for implementing conservation in the commercial sector under the NEP tax incentive program were obtained. The total costs in the base and excursion case are compared in Table 5.2-3. These costs were then distributed uniformly from 1977-1985 in accordance with the previously assumed uniform implementation levels.

TABLE 5.2-2

COMMERCIAL SECTOR CONSERVATION COSTS WITH 10% INVESTMENT TAX CREDIT

Building Type	(a) 1980 SOM Regional Savings ($\times 10^6$ kWh)	(–) 1980 SOM Regional Cost ($\times 10^6$ \$)	(b) Annual Tax Credit ($\times 10^6$ \$)	(c) 1980 SOM Financed Regional Cost ($\times 10^6$ \$)	(d) R&M	(e) 4-Year Tax Credit ($\times 10^6$ \$) 4xb	(f) Costs ($\times 10^6$ \$) c+d-e	(g) Cost of Unit Energy Savings (\$/kWh) f/a	(h) 1985 Alternate Scenario Savings ($\times 10^6$ kWh)	(i) 1985 Alternate Scenario Cost ($\times 10^6$ \$) hxg[1]
Small Office	613	73.7	1.474	82.25	1.89	5.896	78.24	.1276	1231	157.1
Large Office	374	7.8	0.156	9.3	.60	.624	9.28	.0248	1667	41.3
Retail	812	18.6	0.372	20.8	1.38	1.488	20.69	.0255	1790	45.6
School	642	11.8	0.236	12.7	0	.944	11.76	.0183	427	7.8
Other Commercial	1192	33.7	0.674	40.0	3.29	2.696	40.59	.0341	1802	61.4

Total = 321.0

[1] It is assumed that cost of unit energy savings is identical in 1930 and 1985.

5.2.3 Tax Credits for Solar Heating Systems in the Residential and Commercial Sectors

As discussed previously, the implementation levels of solar space and water heating systems were assumed to remain unchanged from the levels in the base case Alternative Scenario despite the tax incentive program. Hence, the tax credits were applied to the base case levels in the Alternative Scenario. Again, implementation of solar heating systems was not considered for the Power Plant Scenario and so no tax credits were involved.

The tax credit program for solar heating systems, as stated in Reference 18 on page 75, differed between the residential and commercial sectors. In the commercial sector, solar heating systems were considered to be treated like any other conservation measure and hence the 10% tax credit was applicable

TABLE 5.2-3

TOTAL COST COMPARISON IN THE COMMERCIAL SECTOR WITH/WITHOUT TAX CREDIT

Building Type	1985 Base Case (x 10^6 $)	1985 Excursion Case (x 10^6 $)
Small Office	169.0	157.1
Large Office	44.0	41.3
Retail	48.0	45.6
School	8.5	7.8
Other Commercial	65.5	61.4
	335.8	321.0

to them as well. In the residential sector, a different and time-varying tax credit was applicable to both types of solar (space and water) heating systems. The tax credit starts at 40% of the first $1,000 and 25% of the next $6,400 in the latter part of 1977 (after April 20). It then declines in stages to 25% of the first $1,000 and 15% of the next $6,400 by December 1984.

Table 5.2-4 provides an illustration of what PNW homeowners would pay for their solar heating systems with and without the tax credit.

TABLE 5.2-4

EFFECT OF TAX CREDIT IN 1977 ON COST OF PNW SOLAR HEATING SYSTEMS (1976$)

	No Tax Credit			Tax Credit[2]			
Solar Application	Unamortized Cost	Amortized[1] Total Cost	Total Investment	Unamortized Cost	Amortized[1] Total Cost	Tax Credit	Total Investment
Space Heat SF>76	$4500	$5346	$5346	$4500	$5346	$1275	$4071
Space Heat MF>76	$1900	$2257	$2257	$1900	$2257	$ 625	$1632
Water Heating (all)	$1260	$1497	$1497	$1260	$1497	$ 465	$ 752

[1]5 year loan; 7% real interest, compounded on monthly balance.
[2]Tax Credit is 40% of first $1,000 and 25% of next $6,400 in 1977.

The results of the tax credit program in the residential sector for the solar systems are tabulated below:

TABLE 5.2-5

EFFECT OF TAX CREDIT PROGRAM ON RESIDENTIAL SECTOR SOLAR HEATING COSTS (1976$)

Solar Application	Total Net Cost[1] without Tax Credit ($\times 10^6$ \$)	Total Net Cost[1] with Tax Credit ($\times 10^6$ \$)	% Cost Reduction Due to Tax Credit
Space Heating (incl. SF>76; MF>76)	184	180	2%
Water Heating	578	562	3.0%

[1]Rounded to nearest million.

Although there is a minor cost reduction resulting from the solar tax credit program, the net cost of solar heating systems remains positive and therefore these systems are still not cost-effective within the 20-year period considered here.

For the commercial sector, the 10% tax credit was applied and the credit was given to the commercial user in the second year after his purchase (as was the case with the residential user). The effect of the tax credit program on the commercial sector solar heating costs is presented in Table 5.2-6.

region, a cost ranging from 80¢ to $1.10 per MMBtu was computed depending on the exact transportation distance involved. The higher price of $1.10 was then used as a conservative estimate in computing coal-derived electricity prices in the base case calculations. Hence it was felt that no change had to be made in the excursion case to these previously computed coal-derived electricity prices for the two scenarios.

The overall effect on electricity prices due to increased natural gas and oil prices was negligible due to the extremely small fraction of electricity generation in the region that is obtained from gas- or oil-fired turbines (less than 1.5% in the Alternative Scenario and 1.2% in the Power Plant Scenario in 1985). Furthermore, natural gas was assumed to be phased out of utility use in combustion turbines and was replaced by distillate fuel in the base case computations, thereby simulating the effect of the NEP natural gas price policy.

5.3.1 Effect of Natural Gas Prices on Total Energy System Costs in the Residential and Commercial Sectors

Residential and commercial consumers of natural gas will not pay the users' tax proposed in the NEP for industrial and utility consumers. However, they will pay the increased price of natural gas as it begins to reflect marginal production costs. Based on data provided in the NEP, a natural gas price schedule was constructed. The NEP (Reference 18, p. 53) states that all new gas sold in the country would be subject to a price limitation of $1.75 per Mcf at the beginning of 1978, but this would increase to $2.20 per Mcf in 1985. With this price range and assuming an average of 1000 Btu's per Mcf, a price schedule can be constructed based on a linear interpolation between the two dates. That schedule is given by the following equation:

$$\text{Price}(t) = \$1.75 + .0643\,(t - 1978) \text{ per MMBtu for } 1978 \leq t \leq 1981$$

Since the fuel cell total energy system assumed for residential and commercial consumers in the Alternative Scenario will not be implemented until 1981, the equation may be rewritten based on that year, and extrapolated to 1995 as well:

$$Price(t) = \$1.943 + .0643 (t - 1981) \text{ per MMBtu}$$
$$\text{for } 1981 \leq t \leq 1995.$$

Based on this natural gas price schedule, the annual fuel-plus-fuel-plus O&M costs were obtained for the two residential and one commercial building types which were assumed to have implemented such TES systems in the Alternative Scenario (see Table 5.3-1). These per-building fuel-plus-O&M costs were then multiplied by the number of buildings of each type in each year that had such systems, based on the same implementation schedules assumed in the base case.

TABLE 5.3-1

REVISED ANNUAL FUEL AND O&M COSTS FOR THE FUEL CELL TES IN THE RESIDENTIAL AND COMMERCIAL SECTORS BASED ON NEP NATURAL GAS PRICES

Building Type	Annual TES Gas Consumption (Btu's)	Annual Fuel Cost Schedule (1976 $)	Annual O&M Cost (1976 $)	Annual Fuel Plus O&M Cost Schedule (1976 $)
Single Family (>76)	106.7×10^6	207.32 + 6.86 (t-1981)	31	238.32 + 6.86 (t-1981)
Multifamily (>76)	99.8×10^6	193.91 + 6.42 (t-1981)	31	224.91 + 6.42 (t-1981)
Average Commercial	21.44×10^9	41,658 + 1,379 (t-1981)	2,790	44,448 + 1,379 (t-1981)

A comparison of the effects on these increased natural gas prices with the base case prices are shown in Table 5.3-2.

TABLE 5.3-2

COMPARISON OF FUEL CELL TES COSTS IN THE BASE AND EXCURSION CASES

TES Sector	Net Cost Base Case ($\times 10^6$ $)	Net Cost Excursion Case ($\times 10^6$ $)
Residential	98.00	140.43
Commercial	-7.90[1]	37.35

[1]Net savings.

Thus, while the natural gas prices increased the net cost as expected in both sectors, in the case of the commercial sector TES it was sufficient to change the TES from marginally cost-effective to cost-ineffective within the 20-year period of interest considered.

Since it was not specified in the Alternative Scenario report the type of total energy system that might be implemented, the fuel cell TES was assumed for purposes of this study. A different type of total energy system, particularly one based on coal rather than natural gas, could prove more effective.[1]

5.4 TOTAL IMPACT ON COST DIFFERENCES BETWEEN THE TWO SCENARIOS

This section describes the impact of the NEP on the two scenarios individually (5.4.1 and 5.4.2) and then the impact on the cost difference between the two scenarios (5.4.3).

5.4.1 Alternative Scenario

The economic impact from the consumers' point of view of the implementation of the President's National Energy Plan on the costs incurred in the base case Alternative Scenario is described herein, subject to the following assumptions described earlier and summarized here.

5.4.1.1 Residential Sector

The implementation levels of insulation specified in the Alternative Scenario in all electrically heated dwelling types have been modified to reflect a uniform 90% level of implementation by 1985 across all residences. Thereafter these levels rise to the Alternative Scenario levels for 1995. The implementation levels of all other conservation measures, passive and active, are unchanged in these residences.

Tax credits are reflected for all conservation programs that fall under the NEP guidelines, i.e., insulation, storm windows, weather stripping, solar space heating and solar water heating, to the tax credit levels

[1] Additionally, as noted previously, sizing the TES to meet peak rather than average demands (an Alternative Scenario requirement) is not economically optimum.

specified in the program. No tax deductions are considered for interest payments on consumer loans. Natural gas prices follow levels recommended in the NEP, which are higher than those assumed in the Alternative Scenario.

5.4.1.2 Commercial Sector

The assumptions in paragraph 2 of subsection 5.4.1.1 also apply to the commercial sector with tax credit levels specific to this sector.

The comparison between the 20-year (1976-1995) total residential and commercial sector costs (in 1976 dollars) in the Alternative Scenario and the respective costs in the excursion case incorporating the recommendations of the National Energy Plan are shown in Table 5.4-1. In the residential sector, the implementation of the NEP results in a net benefit of $394 million to the consumers. In contrast, the commercial sector experiences a small cost increment of about $6 million in the excursion case. In this sector for the Alternative Scenario, the implementation of natural gas total energy systems was a marginally cost-effective measure (by $7.9 million). This trend is significantly reversed when the NEP is implemented (net cost increment of $37.35 million) implying that the increase in natural gas prices inherent in the program

TABLE 5.4-1

TWENTY-YEAR TOTAL COSTS IN THE RESIDENTIAL AND COMMERCIAL SECTORS BEFORE AND AFTER IMPLEMENTATION OF THE NATIONAL ENERGY PROGRAM IN THE ALTERNATIVE SCENARIO ($$10^9$ in 1976 Dollars)

	Alternative Scenario (Base Case)	Excursion Case	Net Savings In Excursion Case
Residential Sector Costs	20.452	20.058	
Commercial Sector Costs	8.764	8.770	
Total Costs in Both Sectors Combined	29.216	28.828	0.388

shifts the balance. In the residential sector, the total energy systems in the Alternative Scenario were not cost effective initially and became less cost effective following the implementation of the National Energy Plan. For solar heating systems the NEP tax credits were not sufficient to make them cost effective in the 20-year analysis period considered here.

5.4.2 Power Plant Scenario

In considering the Power Plant Scenario excursion case, only one conservation measure recommended in the NEP was implemented. This measure was building insulation, which was assumed to be implemented only in the residential sector. The impact of the implementation of the NEP in this scenario results in a cost savings of $535 million as is shown in Table 5.4-2.

TABLE 5.4-2

TWENTY-YEAR COSTS IN THE RESIDENTIAL SECTOR BEFORE AND AFTER IMPLEMENTATION OF THE NEP IN THE POWER PLANT SCENARIO

($\$10^9$ in 1976 Dollars)

Power Plant Scenario (Base Case)	Excursion Case	Net Savings In Excursion Case
26.462	25.927	0.535

5.4.3 Impact On Cost Difference Between Two Scenarios

One interesting comparison that can be made between the Power Plant Scenario and the Alternative Scenario is the difference between the two scenarios of the 20-year cost streams to the consumers before (base case) and after (excursion case) the implementation of the NEP. This is shown in Figure 5.4-1. The comparison before the program implementation was the primary emphasis of this study and has been described in detail earlier.

From Figure 5.4-1 it is seen that, in the initial years, the implementation of conservation programs in the Alternative Scenario in both the excursion and non-excursion cases results in a net cost to the consumers relative to those in the Power Plant Scenario. However, the cost difference between the scenarios is smaller in the excursion case up to 1985 because of all the tax benefits that accrue to the Alternative Scenario in contrast to the single tax benefit (i.e., for insulation) in the Power Plant Scenario. The two cost curves cross over in 1985 reflecting the effect of two trends in the excursion case: 1) the cessation of tax benefits beyond this year tending to increase the conservation costs in the Alternative Scenario;

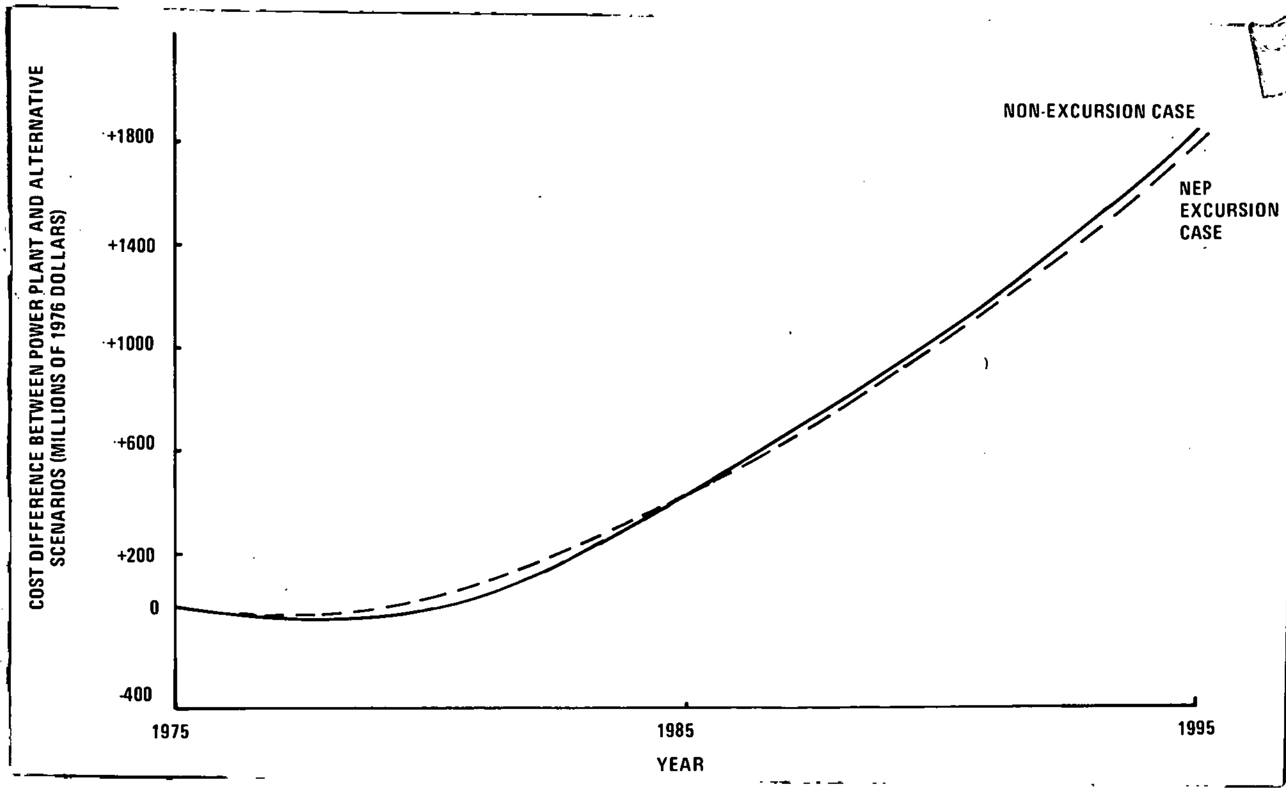


FIGURE 5.4-1. ANNUAL COST STREAM IN THE POWER PLANT SCENARIO LESS ANNUAL COST STREAM IN THE ALTERNATIVE SCENARIO BEFORE IMPLEMENTATION OF THE NATIONAL ENERGY PROGRAM (NON-EXCURSION CASE) AND AFTER (EXCURSION CASE)

and 2) the increasing impact of energy savings from the implementation of cost effective insulation in homes in the Power Plant Scenario which lowers the cost in that scenario. In other words, the consumers in the Power Plant Scenario achieve a new energy cost savings with implementing insulation in their homes that makes the cost difference between the scenarios smaller than it would otherwise be. Annual kWh demand in the two sectors in both scenarios before and after implementation of the National Energy Plan was presented in Figure 5.1-1.

The net present value of the difference in costs for the two scenarios is $6.3 billion. This is almost identical to the cost difference in the base case. Given the expected accuracy of making 20-year cost projections, it can be stated that the NEP had no impact on the net present value of the cost differences between the two scenarios. However, in terms of net-present-valued constant dollars, the difference was $146 million less in the excursion case than in the base case, sufficiently large to state that the NEP had a net beneficial impact on the Power Plant Scenario since the cost difference between the two scenarios decreased by this amount.

5.5 CONSERVATION PROGRAM COMPARISON: ALTERNATIVE SCENARIO AND THE NATIONAL ENERGY PLAN

The Alternative Scenario recommendations for the implementation of energy conservation measures in the PNW region are similar to those in the President's National Energy Plan. In the residential and commercial sectors, both programs recommend similar passive conservation measures (i.e., insulation, storm windows, weather stripping). This is true in the area of active measures as well, where, although the near-term emphasis in the national program is on solar space and water heating, measures such as heat pumps and total energy systems are also considered as viable options--heat pumps today and TES probably in the 1980s. The Alternative Scenario considers all of these as viable in this time period as well. Also, both programs are concerned with improving the energy efficiencies of appliances, which taken as a whole is the largest energy consuming category in the residential sector.

In the industrial sector, with the exception of co-generation, neither program is specific with regard to measures for improving the efficiency of energy utilization. One major difference, however, exists in this sector between the two programs. The Alternative Scenario recommends a rather drastic change in the industrial mix as a viable method for reducing the growth in energy demand. Even though this recommendation is specific to the PNW, such an approach does not constitute energy conservation in the spirit suggested by the NEP. In this respect it significantly differs from the perspective of the national program where no such industrial mix changes are suggested. In the analysis addressing the economic impact of the NEP on the Alternative Scenario, it was not possible to include the industrial sector because of the lack of specific details concerning conservation measures and related costs. However, even if such data had been available, this fundamental difference in the outlook of the two programs would have prevented a meaningful comparison.

6.0 REFERENCES

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APPENDIX A

COSTS OF CONSERVATION MEASURES

Conservation measures in the residential and commercial sectors implemented in the Alternative Scenario and associated capital costs from the Skidmore, Owings & Merrill study (Reference 4).

Table 1

CONSERVATION COSTS IN THE RESIDENTIAL/COMMERCIAL SECTORS (Reference 4)

(1976 Dollars)

BUILDING TYPE	CONSERVATION MEASURES	SOM COST
Single Family Residence - Existing (1,400 ft^2; 3.01 - 3.09 people per unit)	Install semiautomatic night thermostat Weatherstrip doors & windows	$103
	Insulate ceilings from 3" to 12" (R37) Insulate walls with 3 1/2" of U.F. foam Insulate floors from 1" to 6" (R19)	$726
	Install storm windows	$910
Single Family Residence - New (1,550 ft^2; 3.01-3.09 people per unit)	Install semiautomatic night thermostat	$ 65
	Insulate ceilings from 4" to 12" Insulate walls from 3 1/2" to 5 1/2" Insulate floors from 2" to 6"	$539
	Install double glass storm windows insulated glass	$262
Multi-Family Residences - Existing (675 ft^2 per apt., 2.16-2.11 people per unit)	Install semiautomatic night thermostat Weatherstrip doors and windows	$ 83
	Insulate ceilings from 2" to 12" (R37)	(See Next Page)

CONSERVATION COSTS IN THE RESIDENTIAL/COMMERCIAL SECTORS

(1976 dollars)

BUILDING TYPE	CONSERVATION MEASURES	SOM COST
(Continued from previous page).	Insulate walls with 3 1/2" of U.F. foam	$180
	Insulate floors from 1" to 6" (R19)	
	Install storm windows	$338
Multi-Family Residences - New	Install semiautomatic night thermostat	$ 65
($775\ ft^2$ per apt., 2.16-2.11 people per apt.)	Insulate ceilings from 4" to 12" (R37)	
	Insulate walls from 3 1/2" to 5 1/2" (R19)	$171
	Insulate floors from 2" to 6" (R19)	
	Install double glass storm windows	$101
Small office building - Existing	Install semiautomatic night setback thermostat	$3300
($1,500\ ft^2$; 74.3 $kWh/ft^2/yr$)	Install an all electric packaged heat pump	$2700
	[or]	
	Add single glass sheet to inside window	$2000

CONSERVATION COSTS IN THE
RESIDENTIAL/COMMERCIAL SECTORS

(1976 dollars)

BUILDING TYPE	CONSERVATION MEASURES	SOM COST
Small office building - New (1,500 ft^2; 74.3 kWh/ft^2/yr.)	Install automatic night setback thermostat Decrease glass area from 33% to 25% and install double glazing Insulate walls reducing U value from .15 to .08 Insulate roof reducing U value from .10 to .05 Add high performance edge insulation to floor, reducing from 40 to 25 Btuh the U value (per lineal foot)	$5500
	Install a heat pump	$2700
Large office buildings - Existing (50,000 ft^2; 84.7 kWh/ft^2/yr.)	Install timer and optimizer controls on mechanical equipment	$5000
	Install chiller with heat recovery system Modify constant air distribution system to variable-air-volume	$35000
	Install double glazing or storm windows Insulate walls	$50000

CONSERVATION COSTS IN THE RESIDENTIAL/COMMERCIAL SECTORS

(1976 dollars)

BUILDING TYPE	CONSERVATION MEASURES	SOM COST
Large office building - New (50,000 ft^2; 84.7 1Wh/ ft^2/yr.)	Install timer and optimizer controls on mechanical equipment Install chiller with storage tank & heat recovery system Install variable air volume distribution system Use tinted glass & inside window shades	$65,000
Retail buildings - Existing (50,000 ft^2; 72 kWh/ ft^2/yr/)	Adjust dampers to reduce outside air ventilation rate from .10 to .075 cfm per ft^2	$15,000 (?)
	Modify HVAC units to use fresh air for cooling when outside temperatures are suitable	$25,000
	Install double glazing or storm windows Insulate walls	$21,000
Retail Buildings - New (50,000 ft^2; 72 kWh/ ft^2/yr.)	Recover heat from refrigeration compressors Use double glazed windows & window shading Reduce glass area from 40% to 20% - building front wall Lower ceiling height from 20 to 12 ft	$35,000

CONSERVATION COSTS IN THE RESIDENTIAL/COMMERCIAL SECTORS

(1976 dollars)

BUILDING TYPE	CONSERVATION MEASURES	SOM COST
School buildings - Existing (45,000 ft^2; 20.1 kWh/ft^2)	Install double glazing or storm windows Insulate walls	$21,600
School Buildings -	(see (Reference 4)	$0
Other Commercial Buildings - Existing (36,750 ft^2; 42.6 kWh/ft^2/yr.)	Low capital cost conservation systems (average of three previous building types) High capital cost conservation actions (average of three previous building types)	$5,495 $15,555
Other Commercial Buildings - New	Comply with ASHRAE 90-75 standards (average of four building types analyzed) Actions in addition to ASHRAE 90-75 (average of office & retail building types)	$825 $20,873

APPENDIX B

SOLAR SYSTEM DATA

This appendix presents the data supporting the size of the solar collector required to provide 60% of the space heating requirements in residential dwelling units. Table 1 sizes the collector for new single-family dwellings and Table 1 sizes the collector for new multifamily dwellings. For regional monthly average heating degree-day and insolation data see Appendix E.

Table 1.

SOLAR COLLECTOR REQUIREMENTS FOR A SINGLE-FAMILY DWELLING (>76) AFTER IMPLEMENTATION OF PASSIVE CONSERVATION (Assumes 225 ft²)

Month	Average HDD	Monthly Heat Load (x 10^6 Btu)	Collector Incidence (x 10^6 Btu)	n	Useful Heat (x 10^6 Btu)	Supplemental Heat
January	896	5.56	2.57	.467	1.20	4.36
February	675	4.19	4.65	.476	2.21	1.98
March	660	4.10	7.72	.483	3.73	0.37
April	447	2.78	11.2	.409	4.58	-
May	258	1.60	14.16	.244	3.46	-
June	116.3	.72	13.70	.324	4.44	-
July	34.7	.21	15.44	.454	7.01	-
August	41.7	.26	14.16	.417	5.91	-
September	123	.75	9.96	.439	4.37	-
October	361.7	2.24	6.44	.457	2.94	-
November	627	3.89	3.74	.471	1.76	2.13
December	814.3	5.06	2.57	.462	1.19	3.87
		31.4*				12.71 (40.5%)

Provides 59.5% of Heat Load

*May not add due to rounding.

Table 2.

SOLAR COLLECTOR REQUIREMENTS FOR A MULTIFAMILY DWELLING (>76) AFTER IMPLEMENTATION OF CONSERVATION
(Assumes 95 ft^2)

Month	Average HDD	Monthly Heat Load (x 10^6 Btu)	Collector Incidence (x 10^6 Btu)	n	Useful Heat (x 10^6 Btu)	Supplemental Heat
January	896	2.26	1.09	.467	.50	1.76
February	675	1.70	1.96	.476	.93	0.77
March	660	1.66	3.26	.483	1.57	0.09
April	447	1.13	4.73	.409	1.93	-
May	258	.65	5.98	.244	1.46	-
June	116.3	.29	5.79	.324	1.88	-
July	34.7	.09	6.52	.454	2.96	-
August	41.7	.10	5.98	.417	2.49	-
September	123	.31	4.21	.439	1.85	-
October	361.7	.91	2.72	.457	1.24	-
November	627	1.58	1.58	.471	0.74	0.84
December	814.3	2.05	1.09	.462	0.50	1.55
		12.73*				5.01 (39.4%)

Provides 60.6% of Annual Heat Load

*May not add due to rounding.

APPENDIX C

TES DATA

This appendix presents the data upon which the size and cost of fuel cell total energy systems (TESs) determined for implementation in the residential sector were based.

Table 1 presents the data required to compute the peak electricity demand from (non-space heating) appliances in the residential sector. Table 2 presents the data regarding the amount of supplemental space heating required as back-up for a fuel cell TES in a new single-family dwelling. Table 3 presents similar data for a new multifamily dwelling. Table 4 presents the cost data for both new single-family and multifamily dwellings for fuel cell TESs.

Table 1.

FUEL CELL TES CAPACITY REQUIREMENTS

APPLIANCE	AVERAGE kw ELECTRICITY DEMAND[1] 1985	1995	PEAK/AVERAGE RATIO AT SYSTEM PEAK[2]	PEAK APPLIANCE DEMAND (kw) AT SYSTEM PEAK 1985	1995
Water Heater	0.427	0.401	2.215	0.946	0.888
Lighting	0.161	0.146	.97	0.156	0.142
Refrigerator	0.081	0.079	7.33	0.594	0.579
Range	0.119	0,113	3.19	0.380	0.360
TV Color	0.028	0.028	3.19	0.089	0.089
TV B&W	0.019	0,019	1.00	0.019	0.019
Freezer, Clothes Dryer, Clothes Washer, Dishwasher, Air Conditioner, Miscellaneous	0.504	0.548	0.47	0,237	0.258
				2.42	2.34

[1] Average kw is based on 8760 hours/year.
[2] Except for water heating where the ratio increases slightly between 1985 and 1995, the ratio for all other appliances is assumed in the Alternative Scenario to remain invariant with time. See Reference 3 , Table 35, p. 162. The high ratio shown for refrigerators is very likely in error.

Table 2.

FUEL CELL WASTE HEAT PREDICTION FOR SF >76
(Peak Demand 2.4 kW_e)

MONTH	AVERAGE HOURLY POWER DEMAND FROM FUEL CELL (kw)	USEFUL MONTHLY THERMAL OUTPUT* (x 10^6 Btu)	HEATING LOAD (x 10^6 Btu)	DEFICIT (x 10^6 Btu)
JAN	2.40	6.29	5.56	-
FEB	1.20	3.14	4.19	1.05
MARCH	1.20	3.14	4.10	0.96
APRIL	1.07	2.80	2.78	-
MAY	1.07	2.80	1.60	-
JUNE	1.07	2.80	0.72	-
JULY	1.07	2.80	0.21	-
AUG	1.07	2.80	0.26	-
SEPT	1.07	2.80	0.75	-
OCT	1.20	3.14	2.24	-
NOV	1.20	3.14	3.89	0.75
DEC	2.40	6.29	5.06	-
			31.40 x 10^6 Btu	2.76 x 10^6 Btu

*Assumes 70% of waste heat captured as useful heat. Fuel cell efficiency is 40%.

Table 3.

FUEL CELL WASTE HEAT PRODUCTION FOR MF >76

(Peak Demand = 2.4 kW_e)

MONTH	AVERAGE HOURLY POWER DEMAND FROM FUEL CELL (kw)	USEFUL THERMAL OUTPUT (x 10^6 Btu)	HEATING LOAD (x 10^6 Btu)	DEFICIT (x 10^6 Btu)
JAN	2.4	6.29	2.26	-
FEB	1.2	3.14	1.70	-
MARCH	1.2	3.14	1.66	-
APRIL	1.07	2.80	1.13	-
MAY	1.07	2.80	.65	-
JUNE	1.07	2.80	.29	-
JULY	1.07	2.80	.09	-
AUG	1.07	2.80	.10	-
SEPT	1.07	2.80	.31	-
OCT	1.20	3.14	.91	-
NOV.	1.20	3.14	1.58	-
DEC	2.4	6.29	2.05	-
			12.73	

87%

Table 4.

CAPITAL COSTS FOR FUEL CELL TES IN THE RESIDENTIAL SECTOR

(Based on 2.4 kW_e Installed Capacity)

I. TOTAL COSTS

COMPONENT	UNIT COST 1981-1985	UNIT COST 1986-1995	TOTAL CAPITAL COST 1981-1985	TOTAL CAPITAL COST 1986-1995
2.4 kW_e Fuel Cell	\$277/kW_e	\$200/kW_e	\$665	\$480
Heat X'changer	\$90/kW_e	\$90/kW_e	\$216	\$216
Heating Element	\$200	\$200	\$200	\$200
			\$1081	\$896

II. INCREMENTAL COST FOR SF >76

Conventional Heating System Cost			-845	-845
		△Capital Cost =	\$ 236	\$ 51

III. INCREMENTAL COST FOR MULTIFAMILY >76 (No heating element)

Fuel Cell TES Cost			881	696
Conventional Heating System Cost			-343	-343
		△Capital Cost	\$538	\$353

*prorated to SF>76 based on heat load (40.54% of SF>76)

APPENDIX D

SOLAR WATER HEATER SYSTEM DATA

This appendix presents the data supporting the size requirement assumed for a solar water heating collector which provides 60% of the annual water heating requirements of a typical residential dwelling in the PNW. For regional monthly average insolation data, see Appendix E.

Table 1.

SOLAR COLLECTOR REQUIREMENTS FOR RESIDENTIAL WATER HEATING

(Assumes 60 ft^2)

MONTH	HEAT LOAD (x 10^6 Btu)	COLLECTOR INCIDENCE (x 10^6 Btu)	η	USEFUL HEAT	SUPPLEMENTAL HEAT
January	2.24	.65	.467	.29	1.95
February	1.11	1.18	.476	.53	.58
March	1.11	1.95	.483	.89	.22
April	.50	2.84	.409	1.16	-
May	.50	3.57	.244	.87	-
June	.50	3.46	.324	1.12	-
July	.50	3.90	.454	1.77	-
August	.50	3.57	.417	1.49	-
September	.50	2.51	.439	1.10	-
October	1.11	1.62	.457	.70	.41
November	1.11	.93	.471	.42	.69
December	2.24	.65	.462	.29	.80
	11.96				4.65 (39%)
	Provides 61% of annual heat load.				

APPENDIX E

HEATING DEGREE-DAY AND INSOLATION DATA

This appendix presents the basic climatelogical data used in the solar and fuel cell TES sizing calculations. Table 1 presents monthly heating degree-day data for three major cities in the PNW. Table 2 presents daily and monthly average solar insolation data for the PNW region as a whole.

Table 1.

HEATING DEGREE DAY DATA*FOR THREE MAJOR CITIES IN THE PNW

Month	Boise, Idaho HDD	Portland, Oregon HDD	Seattle, Washington HDD	Av. HDD
January	1116	834	738	896
February	826	622	574	675
March	741	598	592	660.3
April	480	432	429	447
May	252	264	258	258
June	97	128	124	116.3
July	0	48	56	34.7
August	12	56	57	41.7
September	127	119	123	123
October	406	347	332	361.7
November	756	591	534	627
December	1020	753	670	814.3
Total				5055

*National Climatic Center, Asheville, N.C., 1941-1970.

Table 2.

MONTHLY AVERAGE INSOLATION DATA FOR THE PNW REGION

Month	Langleys[1,2]	Daily Btu/ft[2]	Monthly Btu/ft[2]
January	100	369	11,439
February	200	738	20,664
March	300	1107	34,317
April	450	1660	49,800
May	550	2030	62,930
June	550	2030	60,900
July	600	2214	68,634
August	550	2030	62,930
September	400	1476	44,280
October	250	922.5	28,596
November	150	553.5	16,605
December	100	369	11,439
Average:	350	1291	
Total	4200	1.55×10^6	

[1] Climatic Atlas of the United States, U.S. GPO, 1968.

[2] 1 Langley = 3.69 Btu/ft^2/day.

Table 3.

EXPECTED SOLAR HEATING DELIVERED TO AN AVERAGE COMMERCIAL BUILDING IN THE PACIFIC NORTHWEST REGION

(Assuming 50,000 ft^2 Collector)

Month	HDD	Heat Load (x 10^6Btu)	Insolation (x 10^6Btu)	η	Useful Heat (x 10^6Btu)	Deficit (If Any)
January	896	858.5	571.9	.467	267.1	591.4
February	675	646.8	1033.2	.476	491.8	155.0
March	660	632.4	1715.8	.483	828.7	-
April	447	428.3	2490.0	.409	1018.4	-
May	258	247.2	3146.5	.244	767.7	-
June	116.3	111.1	3045.0	.324	986.6	-
July	34.7	33.2	3431.7	.454	1558.0	-
August	41.7	40.0	3146.5	.417	1312.1	-
September	123	117.8	2214.0	.439	971.9	-
October	361.7	346.6	1429.8	.457	653.4	-
November	627	600.8	830.3	.471	391.1	209.7
December	814.3	780.0	572.0	.462	264.3	515.7
		4843.6				1471.8

% Heating Load = 69.6% or 3371.1 x 10^6 Btu per year.