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SOLAR-PHOTOVOLTAIC POWER FOR
BROADCASTING STATIONS: AN ECONOMIC ANALYSIS

MASTER

August 1982

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Prepared for
THE U.S. DEPARTMENT OF ENERGY
UNDER CONTRACT NO. DE-AC02-76ET20279

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ABSTRACT

An economic analysis of the profitability for broadcasting stations of replacing conventional electricity with on-site solar photovoltaic power systems has been undertaken. Technological characteristics of these power systems are presented along with the economic assumptions necessary for their evaluation. Time of initial profitability, time of optimal investment, optimum system capacity, and impact of tax incentives on profitability are analyzed for several locations in the country representative of the range of insolation conditions. The analyses indicate that photovoltaic power systems are expected, if cost predictions are met, to prove profitable for the broadcasting market in the Southwest by the early 1980s, in the South by the mid-1980s and in the Northeast by the late 1980s. The study was performed in 1979 and was used to help design an experimental PV power system for a radio station in Ohio, which was installed in that year and has operated successfully ever since.

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1.0 INTRODUCTION

An economic study of solar photovoltaic (PV) power system applications for broadcasting stations has been completed. Daytime only and 24-hour AM stations were considered for three locations in the United States: Boston, Massachusetts; Fort Worth, Texas; and Albuquerque, New Mexico. These cities have insolation conditions that are fair (330 Langleys/day), good (450 Langleys/day), and excellent (500 Langleys/day), respectively.

A stand-alone PV power system design with battery storage, augmented by electric utility power, was selected since most of the power consumed by broadcasting stations is dc and the loads are predictable and constant. The largest station load is the transmitter which may operate, in part, directly from the PV dc bus. Other loads may require dc regulators, and dc-ac inverters would be needed for any 60-cycle loads. DC-DC regulators are more efficient and less costly than dc-ac inverters, especially since dc eventually must be provided for the transmitters.

AM broadcasting stations are a particularly suitable application for PV power systems because the large antenna ground screen area is available for the PV array. Daytime-only stations are most practical, since their operating hours match the sunshine hours; but 24-hour stations, or anything in between, are also possible for such applications. FM and TV stations may be powered by photovoltaics if they are located in rural areas and have land available for the array. Their antennas do not require large ground screen areas but if guy-supported antenna towers are used, land may be available. City-located FM and TV stations are not suitable.

This study considered the economic feasibility of PV for stations by calculating the annual station energy load and energy supplied by the PV array and normalizing the results as the percent of energy furnished by the array to the station. Calculations were made over a typical meteorological year for a variety of array and battery sizes. Then for each of three sets of costing scenarios, determinations were made of when each design would be economical and the profitability. The assumptions underlying the comparison between conventional and solar PV systems are presented and the selection of parameters

discussed. Profitability is computed on both a cost-benefit and commercial calculus for the stations with a 4-kW primary power load. Calculations of profitability for investments in photovoltaics undertaken in each year between 1980 and 2000 indicate the year of initial profitability, the optimal sizes of array and battery, the optimal year for investment, and the impact of investment tax credits on commercial profitability. Profitability for other size stations can be scaled directly. The results are presented as curves and tables showing the percent energy furnished, the surplus energy, the year each system size becomes economical and the profitability.

This study also could be applied to any facility with load characteristics similar to broadcasting stations. Industries with dc loads (such as electroplating) would be suitable if adequate rooftop or land area was available for the PV array. The results of the study are not applicable to utility-interactive inverter systems, large 60-cycle ac loads, or widely variable loads.

At the time of the study (1979), there were in the U.S. about 4400 AM stations (of which 2000 operate from sunrise to sunset only), 3800 FM stations, and 1000 TV stations. The power load of all stations was about 500 MW and the energy consumption was about 9000 MWh/day. Although this is only 0.35% of the total U.S. consumption, it is a significant amount of energy and worthy of consideration for photovoltaics.

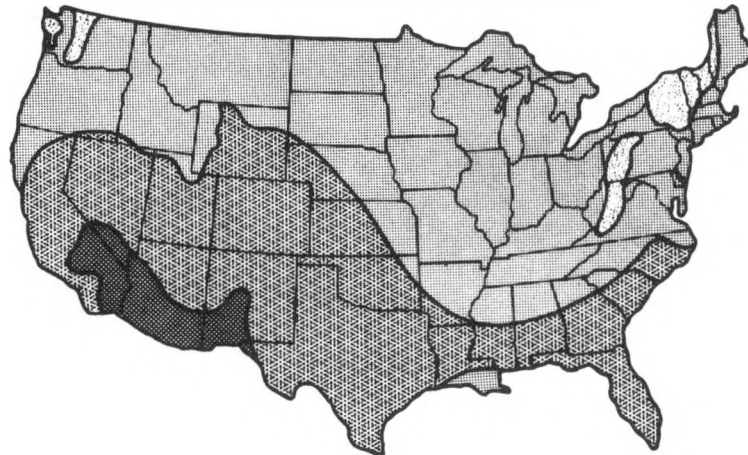
The study was based on a constant 4-kW dc load to the PV power system for both daytime-only and 24-hour stations. This load will easily power a 1-kW (radio frequency power output) station, along with studio equipment and lighting. Other sized stations can be scaled directly.

Boston, Fort Worth and Albuquerque were chosen as representative solar insolation areas. Hourly meteorological data was available for these three areas on computer tape for the year 1963, a typical year. According to the 1970 U.S. Census, 134 million people (66% of the total) live in an area where the average annual solar insolation is similar to that of Boston, 56 million people (28%) live in an area where the insolation is similar to that of Fort Worth, and 3.3 million people (1.6%) live in an area where the insolation is similar to that of Albuquerque. The remainder live in areas

where the insolation is worse than Boston's. Thus, this study represents all the areas of the U. S. with fair or better sunshine. A check of the 1980 Census shows that the population percent figures for the various insolation areas are close to the 1970 values. Figure 1 shows the population-insolation areas of the country.

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MEAN DAILY SOLAR RADIATION (LANGLEYS), ANNUAL
 (LANGLEY IS THE UNIT USED TO DENOTE ONE GRAM CALORIE PER SQUARE CENTIMETER)



KEY	LANGLEYS/ DAY	1970 POPULATION	% OF U.S. POPULATION
	LESS THAN 300	8.8 MILLION	4.4
	300 - 400	133.6 MILLION	66.1
	400 - 500	56.5 MILLION	27.9
	MORE THAN 500	3.3 MILLION	1.6

Figure 1. Population-insolation areas of the U.S.

MIT Lincoln Laboratory, sponsored by the U. S. Department of Energy, designed and built an experimental PV power system for a daytime AM radio station in Bryan, Ohio, in 1979. Sizing for the 15-kWp PV array and the 40-kWh battery system was based on the results of the study for Boston; Ohio has similar insolation. A low-cost design concept was developed, which used prefabricated, transportable components (for easy, fast installation) and required a minimum of site preparation. The estimated high-quantity production component costs were used as the middle-cost prediction in the study. A comprehensive description of the experimental system and the results of two years of operation are described elsewhere^{1,2}.

2.0 SUMMARY OF RESULTS

A summary of the results of the study of radio stations using solar PV power is presented for three locations: Boston (representing low insolation), Fort Worth, (medium), and Albuquerque (high). Measured hourly insolation data for 1963, a typical meteorological year, were used. Both daytime-only and 24-hour stations with a fixed load are included to insure a wide variety of combinations of array and battery sizes for three cost predictions, including the DOE goals.

Figure 2 shows the results of the study for the six cases (a daytime and a 24-hour station located in each of the three cities) for the middle-cost prediction (see Table I, Section 3.0). System size, represented by percentage of annual energy furnished by solar, can be selected for the year the system becomes economical. Small systems become economical early; the longer one waits, the larger the system can be and the greater the dollar saving. For example, a system furnishing half the energy required for a daytime station in Boston would be economical in 1986, but for a system furnishing 90% of the energy, one would have to wait until 1995. For Albuquerque, a system could be built in 1983 to furnish 75% of the energy, but if one waited until 1987, the system would furnish nearly all the energy. Using the conservative cost predictions results in systems becoming economical somewhat later, and using optimistic cost predictions results in systems becoming economical earlier than shown by the curves. The detailed results are presented in the next section and the complete tabulation is presented in the Appendix.

RADIO STATION MIDDLE COST PREDICTION

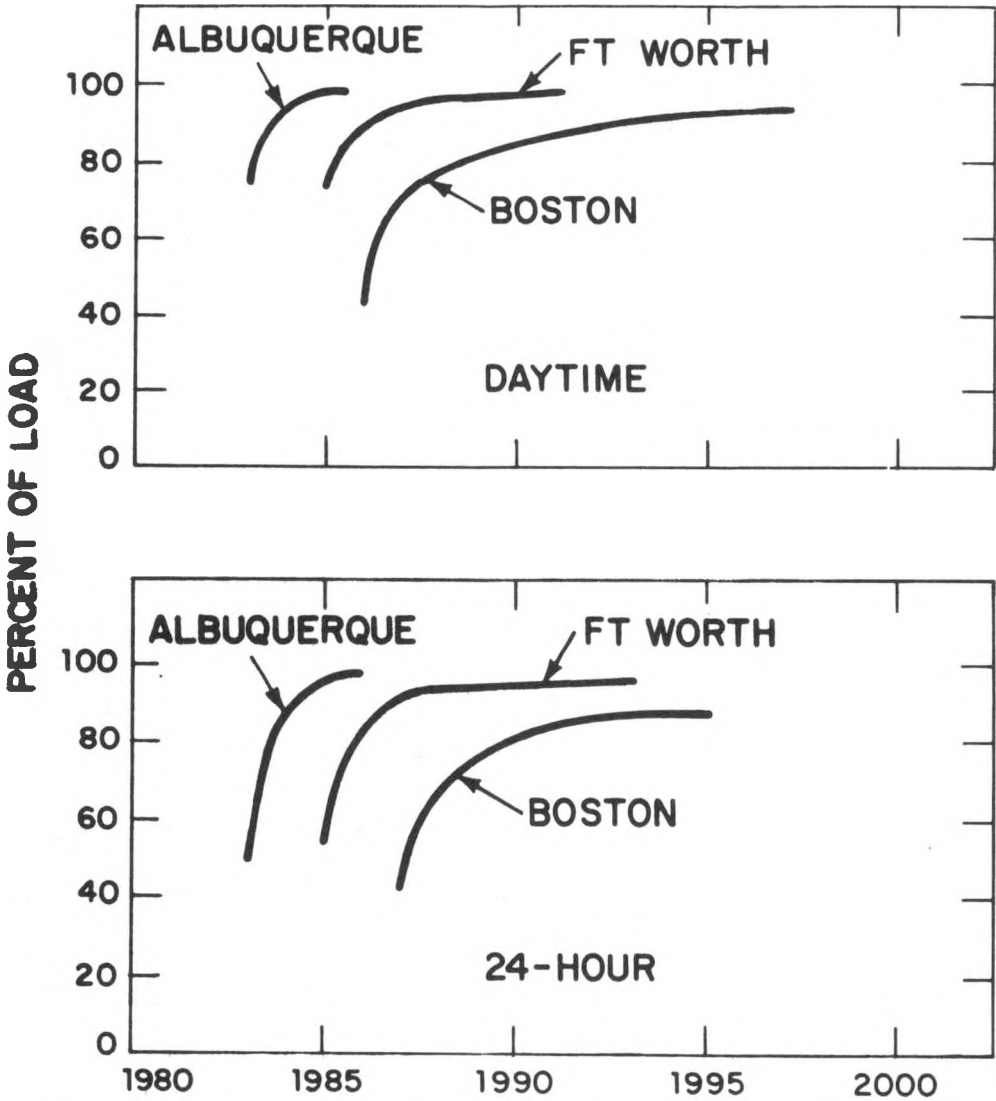


Figure 2. Radio station viability (middle-cost prediction).

3.0 DETAILED RESULTS OF COMPUTER OPERATIONS

PV power system computer simulations were run for a 4-kW dc load for a daytime-only and a 24-hour station for each of three representative insolation areas of the country--Boston, Fort Worth and Albuquerque. Hourly insolation data for 1963, a typical meteorological year, were used. Array sizes from 6 to 35 kWp and battery sizes from 10 to 300 kWh were included.

The first program calculated system performance by listing energy (MWh/yr) consumed by the load, energy furnished to the load by the array (% of total load), and array surplus energy (% of total load). The annual energy consumed for the 4-kW fixed load used in the study was 17.5 MWh for daytime only and 35.0 MWh for 24-hour station operation. The control strategy in the program was such that when the battery became discharged to the 25%-of-full charge point, a utility-powered power supply was turned on and replaced the battery discharge current, sharing the load with the array. When the array could furnish all the load current and start recharging the battery, the power supply was turned off. The results are shown in Fig. 3 for the six cases and are tabulated in the Appendix.

The solid curves show the percent of the load furnished by the PV power system for the various array and battery sizes. The remainder of the load had to be furnished by the local electric utility via the power supply. The dashed curves show the array surplus energy as percent of the load for the various array and battery sizes.

For a daytime Boston station, a 15-kWp array with a 100-kWh battery appears to be a good choice, furnishing 86% of the annual load with only 17% surplus energy. For the 24-hour station, a 25-kWp array with a 200-kWh battery would furnish 84% of the load with a 12% surplus.

For a daytime Fort Worth station, a 12-kWp array with a 100-kWh battery would furnish 93% of the load with a surplus of 10%. For the 24-hour station, a 25-kWp array with a 150-kWh battery would furnish 90% of the energy with a 20% surplus.

For a daytime Albuquerque station, an 8-kWp array with a 40-kWh battery would furnish 92% of the load with a surplus of 10%. For the 24-hour station, a 15-kWp array with a 100-kWh battery would furnish 85% of the load with a 3% surplus.

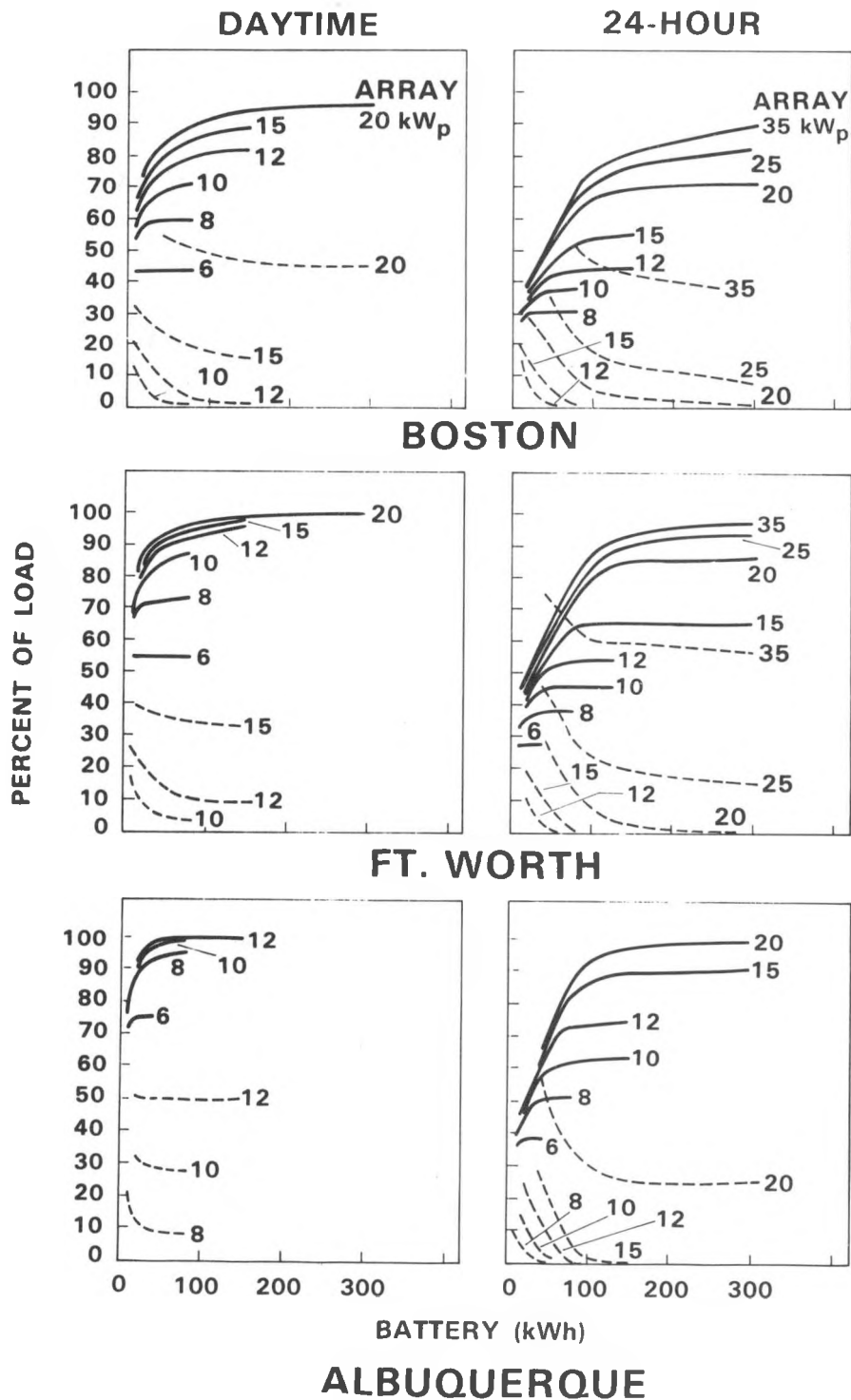


Figure 3. System performance shown as percent of annual load furnished by the array for 3 insolation areas, 2 station operation times, for various array and battery sizes. Solid lines show array output, dashed lines show surplus energy.

A 15-kWp array and a 40-kWh battery were selected for the experimental PV power system for the radio station in Ohio. A system of modest size was chosen to keep the costs as low as possible. The study predicted that about 78% of the annual energy would be provided by the array. Over the first year's operation, the monthly averages ranged from 75 to 100%, with a yearly average of 90%. This is higher than predicted because the actual load was somewhat lower and the battery capacity somewhat higher than planned and the 1979-80 year was sunnier than average. Which array and battery sizes are the most economical was determined by the second program.

The second program determined the economics of the systems by calculating the net value (benefits minus costs) for each year of system installation from the year 1980 to 2000. Three sets of runs were made for each system size, for three predicted cost scenarios: Case I for costs on the low or optimistic side, Case II for the middle predictions which are very close to the DOE goals, and Case III for predictions on the high or conservative side. All costs are in 1975 dollars. Table I shows the values used for each case. The rationale for these values is given in the next section of this report. The results are shown in Fig. 4 for the six cases (and three cost scenarios) for the largest economical system for the year of installation. Figure 5 shows the results for the most profitable system for the year for the 4-kW load size station. Other station load sizes may be scaled. The complete tabulation of results is presented in the Appendix.

Small systems become economical early; the longer one waits, the larger the system can be and the greater the dollar saving. For example, a system furnishing half the energy required for a daytime station in Boston is economical in 1986; but for a system furnishing 90% of the energy, one would have to wait until 1995. For Albuquerque, a system could be built in 1983 to furnish 75% of the energy; but if one waited until 1987, the system would furnish nearly all the energy. Using the conservative cost predictions results in systems becoming economical somewhat later, and using optimistic cost predictions results in systems becoming economical earlier.

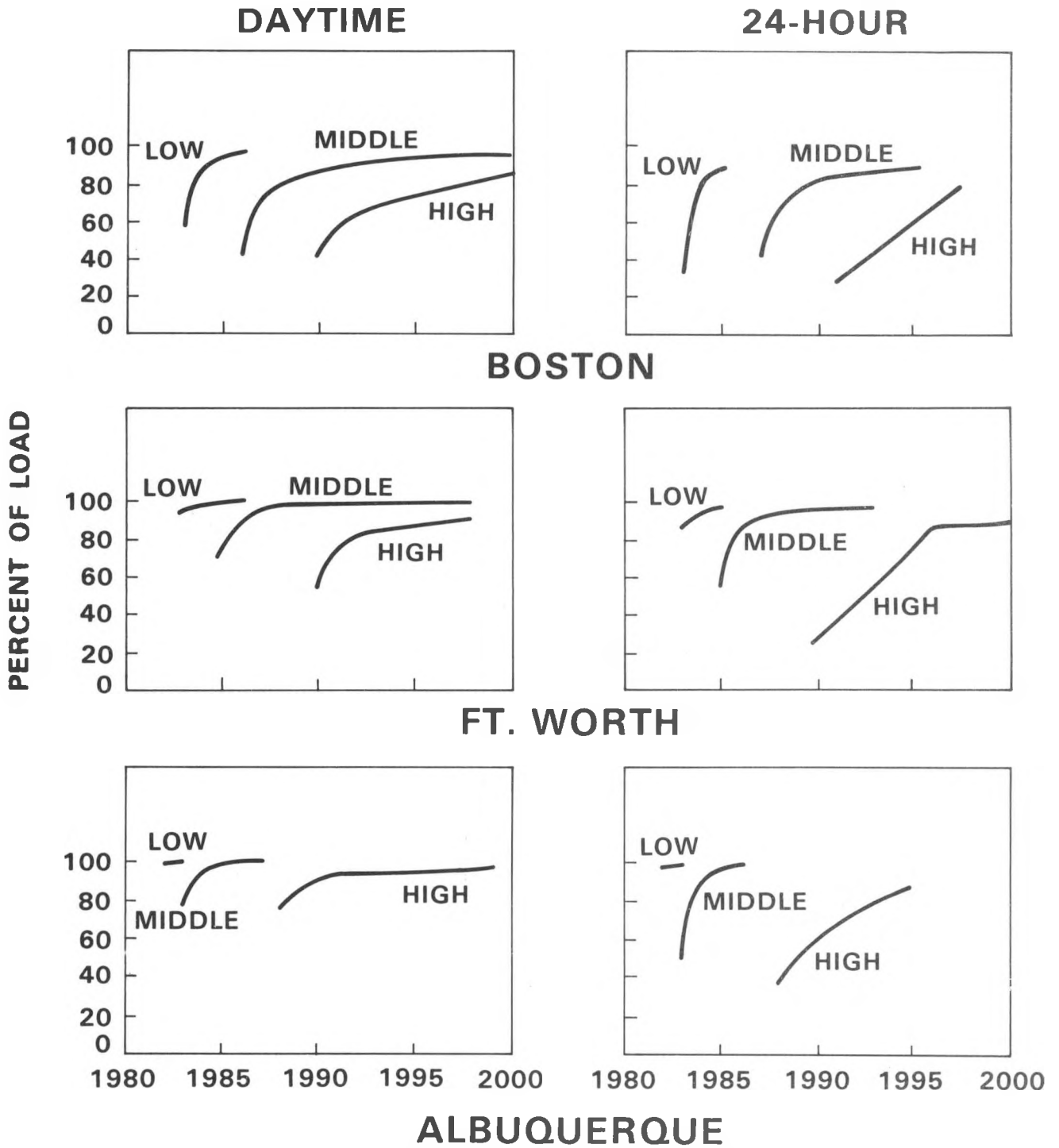


Figure 4. Economic viability shown as percent of annual load furnished by the array, for the year of installation, for low, middle and high predicted cost scenarios, for 3 insolation areas, and for 2 station operation times, for the largest system for the year.

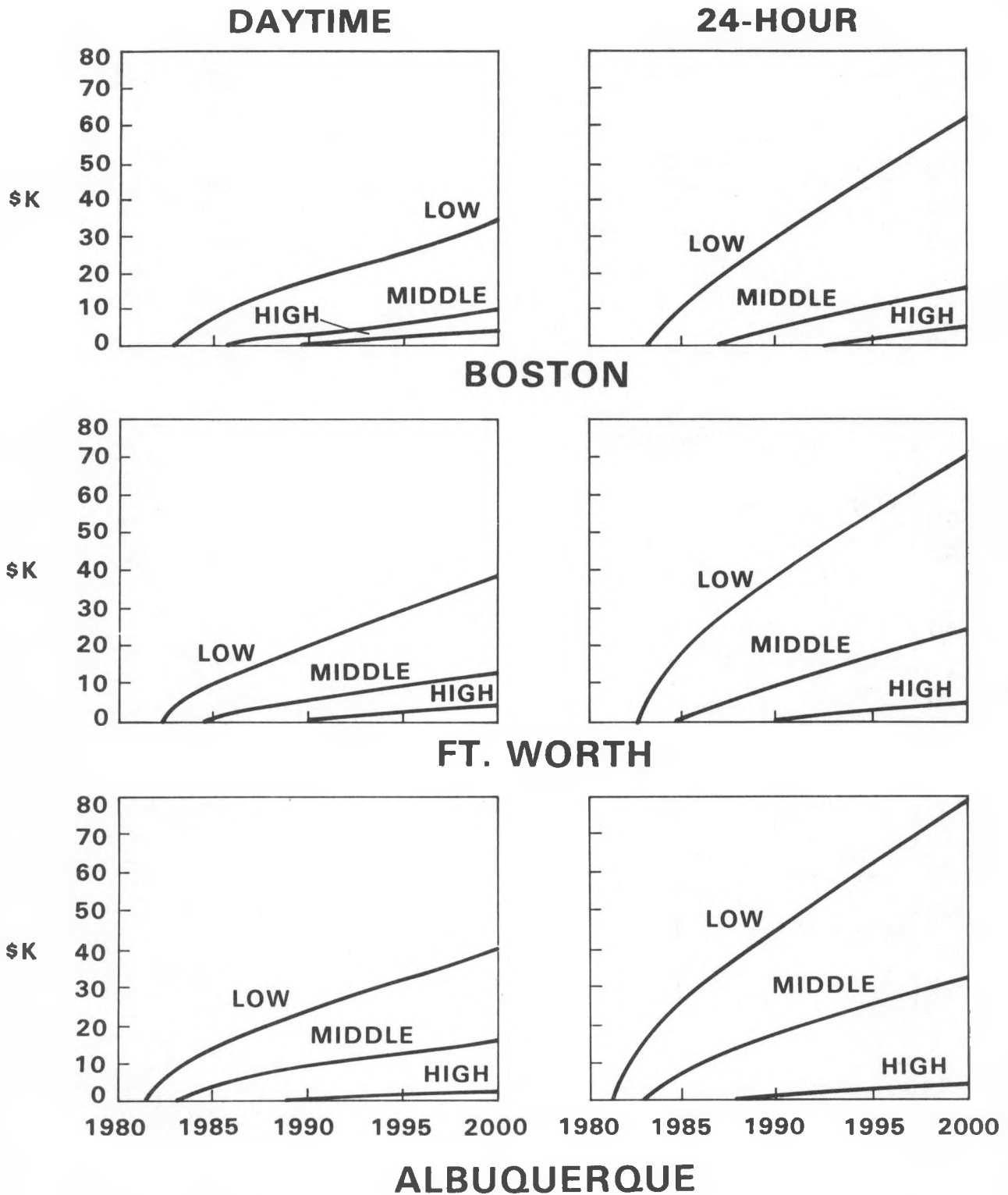


Figure 5. Profitability for a 4-kW size load station for low, middle and high predicted cost scenarios, for 3 insolation areas, and for 2 station operation times, for the most profitable system for the year.

TABLE I
PV POWER SYSTEM PREDICTED COSTS
(1975 dollars)

	Case I Low (\$/Wp)	Case II Middle (\$/Wp)	Case III High (\$/Wp)
PV modules	15.00 - 1976 .50 - 1986 .10 - 2000	15.00 - 1976 .50 - 1986 .20 - 2000	15.00 - 1976 .50 - 1986 .30 - 2000
Battery	.30 (\$30/kWh)	.65 (\$65/kWh)	1.00 (\$100/kWh)
Battery life	15 years	13 years	11 years
Balance of System	.40	.60	.80
TOTAL in 1986	1.20	1.75	2.30
TOTAL in 2000	.80	1.45	2.10
	Case I Low	Case II Middle	Case III High
Electricity Cost Escalation (discounted for inflation)	\$.05/kWh 4%/year	\$.05/kWh 3%/year	\$.05/kWh 2%/year
Real Discount Rate	3%	5%	8%
Tax Credit (one time)	10%	10%	10%
Maintenance	\$.15/Wp/year	\$.20/Wp/year	\$.25/Wp/year
System Life	20 years	20 years	20 years

4.0 ECONOMIC ANALYSIS

4.1 Cost-Benefit Approach

The profitability of replacing conventional sources of electricity with solar photovoltaics is analyzed as an investment decision. The PV system incurs a large front-end cost; its benefits are the stream of savings in conventional electricity bills for the life of the equipment, T. The net benefit or profitability is computed in equations (1) through (3).

The net benefit of an investment in solar photovoltaics of design capacity, h; in year, j; in region, k; under cost scenario, m; is represented by equation (1):

$$\text{NET}_{hjk m} = \text{BENEFIT}_{hjk m} - \text{COST}_{hjk m}. \quad (1)$$

In the present analysis, computations are undertaken for systems designed to meet from 40 to 100% of the load, by varying the size of the array (A_h) and capacity of the storage batteries (BAT_{hm}). While most of the costs of the solar PV system are incurred in the year of investment, batteries must be replaced at some year, M, in the project life cycle. In addition, there are yearly maintenance costs for the PV system, which are subtracted from the annual benefits. The reason for the treatment of maintenance costs in this manner is that their discounted value depends upon the same interest rate which is utilized to discount electricity savings. The system costs in year j are computed from equation (2):

$$\text{COST}_{hjk m} = \left(\left[X_m + (15,000 - X_m) e^{-j/p} \right] + \text{BSC}_m \right) A_h + \text{BAT}_{hm}. \quad (2)$$

where X_m is the year 2000 target cost per peak kW; where $j = 0$ in 1977; where the BSC_m represents balance-of-system costs; where A_h is the peak kilowattage of the array; where BAT_{hm} is battery capacity; where p represents the rate of decrease in array costs according to DOE projections; and where the subscript m refers alternatively to conservative, middle and optimistic cost scenarios, discussed below.

Except for the batteries, components of the PV system are expected to function in perfect working order to $T = 20$ years. Thus the discounting of

the stream of benefits occurs over this time horizon. The present value of these benefits is computed from equation (3):

$$\text{BENEFIT}_{hjkm} = \sum_{t=j+1}^{j+T} \frac{(k\text{WSV}_{hk} \text{ ELEC}_k) e^{rt} - \text{SM } A_{hk}}{e^{i(t-j)}} - \frac{\text{BAT}_{hm}}{e^{im}} \quad (3)$$

where kWSV are the kilowatt-hours of conventional electricity saved by the PV system, ELEC_k is the "shadow" price of electricity in region k in 1977, SM is annual system maintenance costs, r is the escalation rate in electricity costs, and i is the discount rate.

Net benefits are computed for each year of investment beginning with 1977, using prices of that year in all subsequent calculations, computations are in constant dollars in 1975 and both electricity escalation rates and discount rates are "real," or abstracted from inflation.

4.2 Parameters

The parameters undertaken in the cost-benefit analysis and the values they take merit careful discussion (see Table I).

Array Costs - The costs of the arrays are taken as DOE targets for a combination of flat-plate and concentrator technologies. Taking alternative year 2000 goals of \$100 per peak kilowatt (the optimistic scenario) and of \$300 per peak kilowatt (the conservative scenario), curves are fitted which pass through the 1976 price for flat-plate arrays (\$15,000), the DOE 1981 goal for concentrator arrays (\$2000), and the 1986 flat-plate target (\$500). The target rate of cost decrease (about 40% per year prior to 1986) was realized during the 1976-79 period. Simulations are undertaken with the following peak kilowattage: 6, 8, 10, 12, 15, 20, 25 and 35.

Batteries - Three scenarios for battery cost, BAT, and lifetime, M, are suggested for the 1980s and beyond. Under conservative assumptions, batteries will cost \$100 per kilowatt hour and last for eleven years. Under middle and optimistic assumptions, these figures are \$65 and 13 years, \$30 and 15 years, respectively. Simulations are undertaken with the following battery storage capacities in kilowatt hours: 10, 20, 40, 80, 150 and 300.

Balance-of-System Costs - The balance-of-system costs include the PV module frames and cables, controls, backup-power-supply site preparation,

foundations and installation. These expenses are minimal and exclude new building for the batteries and controller.

Table II shows the estimated balance-of-system costs for low, middle and high-cost scenarios and is based on the projected high-quantity production costs for the components used in the 15-kWp Ohio radio station system. The array power density for the Ohio station was only 50 Wp/m². It is projected that double this density can be provided in the future and that only half as many racks and cables will be required. The manufacturer of the racks claims that rack design modifications cut the weight nearly in half and that the high-quantity costs would decrease by half, thus offering a 4-to-1 reduction in the array-mounting-structure costs. The other actual costs for the Ohio system are listed in the table along with their projected high-quantity costs, all in 1975 dollars.

Kilowatt Hours Saved - Kilowatt hours saved by the solar PV system depend upon array size, battery capacity and insolation patterns at the site, as indicated above. The analysis here assumes the surplus electricity is wasted rather than fed back to the utility or used on-site for lighting, heating or the like.

"Shadow" Electricity Costs - Conventional energy savings are not based upon observed prices, but upon "shadow" prices that reflect the opportunity cost or replacement cost of energy. Current fuel prices in the United States reflect: a) regulations on the price of gas of different types and vintages (old gas versus new gas) and b) for many utilities, prices contracted prior to 1973. With the deregulation of oil prices in the United States, fuel costs have been rapidly approaching world levels, and the cost of oil and gas have been converging on the basis of BTU content, with obvious correction for cleanliness or ease of handling. In 1975, the "shadow" or asymptotic world price of oil was approximately \$3 per million BTU or 5¢ per kilowatt-hour of generated electricity.

There are considerable variations in electricity costs among and within regions. Some of the variations can be explained by the timing of fuel contracts--some utilities are still purchasing fuels at pre-1973 prices--and by the current variations in the use of controlled versus decontrolled fuels--regions like New England depend upon oil imports, paid at the world price, while others

TABLE II
BALANCE OF SYSTEM COSTS
(1975 Dollars)

	15-kWp Ohio Station		Study Predicted Costs		
	As Built	Projected	Low	Middle	High
Racks, Qty	100	50			
Cost, ea.	\$160	\$80			
Power, ea.	150 W ₂	300 W ₂			
\$/ft ²	32 ft ² 5.00	32 ft ² 2.50			
\$/Wp	1.07	.26	.15	.26	.37
Cables, Qty	100	50			
Cost, ea.	\$50	\$30			
\$/ft	300 ft .17	300 ft .07			
\$/Wp	.33	.07	.05	.07	.09
Controls					
Cost	\$3000	\$1500			
\$/Wp	.20	.10	.06	.10	.14
Power Supply					
Cost	\$3000	\$ 750			
\$/W	4 kW .75	4 kW .19			
\$/Wp	.20	.05	.04	.05	.06
Site Preparation					
Area	15000 ft ²	7500 ft ²			
Cost	\$1800	\$ 900			
\$/Wp	.12	.06	.05	.06	.07
Blocks, Qty	900	450			
Cost, ea.	.60	.60			
Total Cost	\$540	\$270			
\$/Wp	.04	.02	.02	.02	.02
Installation					
Man Hours	96 @ \$12	48 @ \$12			
Cost	\$1152	\$ 576			
\$/Wp	.08	.04	.03	.04	.05
GRAND TOTAL \$/Wp			.40	.60	.80

have had access to price-controlled fuels. As price controls are phased out and as old fuel contracts expire, oil and gas prices are likely to converge to a national norm. Nevertheless, there may be persistent differences in electricity costs as a result of differences in load factors, customer densities, availability of cheap hydroelectric sources and distance from coal deposits. These persistent regional factors are likely to result in New England and the Middle-Atlantic states paying 10-20% more than the national average for electricity; states in the Pacific Northwest and the Tennessee Valley, about 10-20% less³. The present analysis is conservative and generally ignores these inter-regional differentials. As indicated by a special analysis that assumes Boston pays 20% more than Fort Worth and Albuquerque, these differentials may have a major impact on profitability.

Finally, the analysis pays little attention to energy price structures, in particular, to the nature of commercial rates or the peak-load/time-of-day pricing. Commercial rates have typically been a third higher than residential rates during the past twenty-five years⁴. To the extent that these rate differentials persist, the present analysis underestimates the benefits of solar PV. The Public Utilities Regulatory Policy Act of 1978 has been pushing regulatory commissions in the direction of cost-of-serve pricing. To the extent that these efforts succeed, the differentials should vanish and even reverse. Another thrust of the Act is toward time-of-day pricing. Since daytime radio stations broadcast during peak, shoulder and off-peak periods year round, the effect of time-of-day rate structures is not especially great. Radio stations that broadcast for 24 hours will enjoy some reduction in electricity costs, which makes solar PV somewhat less attractive. Because the nature of the future rate structures is unclear and their impact relatively small, time-of-day pricing is ignored in the present study.

Electricity Escalation Rate - The escalation of electricity costs depends upon the rate of increase of fuel prices, the rate of increase of capital costs, and relative importance of capital and fuel in generating electricity.

Fuel escalation rates were chosen on the basis of a review of a large number of studies on the basis of the economic theory of depletable resources. This theory states that fuel escalation rates cannot be expected to increase

at a rate higher than the interest rate for any prolonged period. If these were to occur, producers would merely withhold or "bank" the fuel. Such banking would cause a once-and-for-all increase in fuel costs (like that experienced in 1973), after which time fuel escalation rates would increase at less than the interest rate⁵. Studies by DOE and the MIT Energy Laboratory suggest that the plausible range of fuel escalation rates is 2 to 4% per annum^{6,7}.

Because of increasing delays caused by regulations affecting power plant construction, capital costs of new generating capacity are rising at a faster rate than fuel. Because of lags in adjusting energy tariffs to escalations in fuel prices, electric utilities are now riskier enterprises than before, having to pay a premium on their borrowings. To the extent that the institution of time-of-day pricing improves load factors and reduces capital requirements, the capital-intensity of electric utilities may somewhat diminish. On balance, 2 to 4% above inflation would appear as the plausible range of electricity escalation.

System Maintenance Cost - Field tests should provide ample information on the maintenance costs of solar PV systems. In the absence of definitive information at this time, maintenance costs take the values of \$15, \$20 and \$25 per peak kilowatt.

Discount Rates - The selection of the proper discount rate is less than straightforward. Since all calculations are made in constant 1975 dollars, real rather than nominal or observed interest rates are relevant. The fact that nominal interest rates reflect the rate of inflation anticipated by financial institutions, including inflation in both the fuel escalation rate (in the numerator) and the discount rate (in the denominator), has a self-cancelling effect on the present value of benefits.

One measure of the interest rate is the market rate for long-term real estate mortgages. In the 1950s, when the rate of inflation was minimal, these mortgage rates were about 2 to 3%. In 1979, when inflation hovered in the 8 to 10% range, mortgage rates were about 11 to 12%, again suggesting a real interest rate of about 2 to 3%. A somewhat riskier mortgage on solar PV systems might command a slightly higher interest rate, say 3 to 4%. At the

other extreme, some cost-benefit analysts utilize the return on equity of blue-chip corporations as the proper interest rate. Intermediate interest rates on the order of 5% are often used by cost-benefit analysts on the grounds that government ought to take a longer view of investments than private corporations. The Office of Management and Budget sets the nominal interest rates on public projects at that of long-term Federal Funds, which sold at 7-1/8% as of July 1979. This suggests a real interest rate approximating zero. In this analysis, alternative interest rates of 3, 5 and 8% are utilized.

4.3 Commercial Profitability

Commercial calculations differ from cost-benefit calculations by the consideration of taxes. First, conventional electricity payments as well as maintenance and interest charges on solar PV systems are tax deductible. Second, depreciation as an accounting item is generally more rapid than actual physical depreciation. Indeed, under the assumptions of the analysis above, no physical depreciation occurs until the twentieth year, when the system depreciates completely. Third, general and specific tax credits are provided for solar energy investments.

The value of a tax deduction depends upon the marginal tax rate, R . These tax rates are 20% for the first \$25 thousand of corporate profit, 22% for the next \$25 thousand of corporate profit, and 48% for all subsequent profit. Businesses which are closely-held corporations or partnerships are taxed at the personal income tax rate. Taking 20% as representative for small businesses, a \$100 dollar expense reduces profits by $(1-R) 100$, or by only \$80.

The assumption of the analysis is that 100% financing is available for the solar PV system. Interest costs, but not amortization, are tax deductible. On the assumption of level-payment financing, as in house mortgages, there are high deductions for interest costs in the early years of the investment life.

The depreciation method utilized is sum-of-years-digits, which normally provides the highest present value of depreciation.

The Tax Reform Act of 1978 established a 10% investment tax credit, which will diminish to 7% after 1980. The National Energy Act of 1978 introduced

additional credits for energy-saving and solar-using investments of 10% until 1982. The combined tax credits sum to 20% until 1980, 17% until 1982 and 7% thereafter. The recent Economic Recovery Act establishes even more generous tax credits. Because these credits may expire in the future, a conservative assumption of a combined 10% tax credit is assumed. This one-time tax credit implies that a \$1000 investment will add \$100 to after-tax profits immediately.

The present value of commercial profitability of a solar PV system of design capacity h , in year j , in region k , under cost scenario m is represented by equation (4):

$$\text{COMM}_{hjk m} = (1-R) \sum_{t=j+1}^{j+T} \frac{B_t - I_t}{e^{i(t-j)}} + R \sum_{t=j+1}^{j+T} \frac{D_t}{e^{i(t-j)}} + \sum_{t=j+1}^{j+t} \frac{AM_t}{e^{i(t-j)}} + 0.1 \text{ COST}_{hjm} \quad (4)$$

where B_t represents annual benefits as expressed in equation (2), D_t is annual depreciation, AM_t is amortization. The undiscounted sums of both depreciation and amortization are equal to cost:

$$\text{COST}_{hjm} = \sum_{t=j+1}^{j+t} D_t = \sum_{t=j+1}^{j+t} AM_t. \quad (5)$$

4.4 Levelized Electricity Costs

A commonly used concept in evaluating electricity-generating investment is levelized costs. These are costs per kilowatt hour determined by annualizing capital costs and maintenance costs. While the notion of levelized electricity cost has lost much of its validity for electric utilities in a period of steeply rising fuel and capital costs, it provides a useful measure of the average costs per kilowatt hour for solar PV systems.

The levelized electricity cost of a system of design capacity h , in year j , in region k , under cost scenario m is computed in equation (6):

$$\text{LEC}_{hjk m} = \frac{\text{CRF}_m \text{ COST}_{hjm} + \text{BAT}_{hm} e^{-iM} + \text{SM} A_{hk}}{\text{kWhr}_{hk}} \quad (6)$$

where CRF_m is annual debt service (interest plus amortization) as a proportion of capital costs under interest rate scenario m ; $COST_{hjm}$ is front-end capital cost of the solar PV system; $SM S_{hk}$ is the cost of maintaining the arrays; $BAT_{hm} e^{-iM}$ is the discounted value of the replacement battery from the year of replacement; and $kWhr_{hk}$ are the annual kilowatt hours utilized from the PV system. As less than all of the electricity generated is actually utilized in the radio broadcasting application, levelized electricity costs are biased upward. In actuality, auxiliary use of the surplus electricity on site or fed back to the utility would reduce these levelized costs.

Summary of Approach

The levelized cost indicates the price for photovoltaic electricity that would permit the system owner to fully recover the capital investment. The higher the discount rate, the greater is the capital recovery factor, and hence the levelized cost. This cost can be calculated from a social point of view, as in equation (6), or from the viewpoint of a profit-making enterprise, like a radio station. Because of tax deductions and tax credits, the levelized cost from a commercial point of view is less than that from a social point of view. When the levelized cost is examined from the social viewpoint, the correct comparison is the price of conventionally generated electricity, say 5 cents/kWh in 1975. When levelized cost is examined from the commercial viewpoint, the correct comparison requires reducing the cost of conventionally generated electricity by the relevant marginal income-tax rate. Thus the 5-cent cost of conventional electricity to a business in the 20% tax bracket is only $5(1-.2) = 4$ cents/kWh.

If electricity prices are expected to escalate, then the assessment of levelized costs becomes more complicated. This is because levelized costs must be compared to levelized benefits. For example, if electricity is expected to escalate at 4% a year for twenty years, then the levelized social cost at a starting point of 5 cents/kWh and a discount rate of 8% is 6.9 cents.

Calculations of cost-benefit, commercial profitability and levelized electricity costs are undertaken for daytime and 24-hour radio stations in three locations with varying insolation conditions. While each of the simulated radio stations used 4-kW primary power, the results can be scaled proportionally for broadcasting stations of any size.

The calculations are undertaken for investments in solar PV undertaken alternatively in all the years between 1977 and 2000. The parameters utilized in the conservative, middle, and optimistic scenarios are summarized in Table I.

5.0 ANALYSIS OF RESULTS

5.1 Cost-Benefit Analysis

The results of the cost-benefit analysis are quite sensitive to which scenario is utilized, moderately sensitive to differences in insolation among the three sites, and fairly insensitive to the distinction between daytime and 24-hour radio stations. This latter finding suggests that the results here can be generalized and scaled upward to the entire broadcasting sector.

Date of Initial Viability - Under the optimistic scenario, a solar PV system becomes competitive with conventionally generated electricity in the early 1980s. Under the middle scenario, the initial viability moves to the mid- and late-1980s. Under the conservative scenario, systems become competitive with conventional electricity during the 1990s.

The initially viable systems provide a relatively low percentage of the required load. This percentage is obviously higher for daytime than for 24-hour stations. Under all three scenarios, the initially viable system provides about 40% of the 24-hour load and 50% of the daytime load in Boston, but around 70% of the daytime load in Albuquerque.

Maximum Feasible System Size - Beyond the year of initial viability, increasingly large systems become economically viable. Because array costs continue to fall while electricity costs continue to escalate, the costs of maintaining excess capacity diminish and the benefits of increasing load coverage increase. Only under the optimistic scenario does the feasible system cover the entire load, generally in the later years. Under any scenario, the maximum feasible load coverage is greatest in Albuquerque and smallest in Boston, at any given year. In any given year, the feasible load coverage is greater for daytime than for 24-hour radio stations. This is because increasing coverage for the 24-hour station requires increased use of expensive batteries per kilowatt hour of electricity saved.

Optimal System Size - In any given year, the economically optimum system size is generally smaller than the maximum viable system size. This is because of increasing marginal costs of load coverage; i.e., covering the first 10%

of the load. While larger systems cover a larger proportion of the load, they also generate a larger proportion of electricity as surplus. This suggests that invention of profitable ways of disposing of this surplus can enhance the profitability of systems with larger load coverage.

Optimal Phasing of Investment - From a narrow economic point of view, it is not necessarily desirable that investments in solar PV systems be undertaken in the initial year of viability. Because the cost of arrays is expected to decline rapidly during the 1980s, the postponement of the investment can yield an increase in net benefits. So long as the rate of increase in net benefits after the year of initial viability exceeds the discount rate, it pays to wait. The rule for determining the optimum year for investment is to select the year j , and the net benefits discounted to the present which are maximal:

$$\text{max present value (j)} = \text{net}_j / e^{ij}. \quad (7)$$

The optimal year of investment is generally several years beyond the year of initial viability. When other factors such as energy independence are taken into account, this simple concept of optimality must be modified. The use of tax credits to bring the optimal year forward are considered below.

5.2 Commercial Calculations

Taking taxes and financing into account generally shortens the period before which solar PV systems can become viable, increases the size of the maximum feasible system, and advances the year of optimal investment.

Small tax credits can have a great impact on accelerating the adoption of PV systems. This is because the curve of net commercial value of investment, discounted to the present, is relatively flat around the optimal year. In the case of Boston, the optimum year for a 15-kW system under the middle scenario is 2000. The present value of this system, however, is only about \$100 less one year earlier. A tax credit equal to 1% of the costs could accelerate adoption by one year. The credit necessary to accelerate adoption by four years is only 2% and by five years, only 3%.

Similarly, investment tax credits can raise the optimum size of investment. This is because the incremental cost of expanding capacity is diminished by the tax credit.

5.3 Levelized Costs

The levelized costs from the commercial viewpoint are indicated for the three cities in Table III.

TABLE III
LEVELIZED COST OF PHOTOVOLTAIC AND CONVENTIONAL ELECTRICITY,
COMMERCIAL VIEWPOINT: THREE SITES, 1985 & 1990

<u>Photovoltaic Electricity</u>	<u>1985</u>	<u>1990</u>
3% Discount		
Boston	9.8	6.5
Fort Worth	7.1	4.8
Albuquerque	6.4	4.3
5% Discount		
Boston	11.7	7.8
Fort Worth	8.5	5.7
Albuquerque	7.7	5.1
8% Discount		
Boston	14.8	9.9
Fort Worth	10.9	7.3
Albuquerque	9.8	6.5
<u>Conventional Electricity</u>		
3% Discount/4% Fuel Escalation	8.8	10.7
5% Discount/3% Fuel Escalation	7.0	8.2
8% Discount/2% Fuel Escalation	5.7	6.3

In 1985, the levelized cost of electricity in Boston is 9.8 to 14.8%, depending upon the discount rate. Because insolation is about one and a half times greater in Albuquerque, levelized costs there are about two-thirds as great. Costs in Fort Worth are about midway between Albuquerque and Boston. By 1985, the levelized cost of conventional electricity to the radio station will lie in the range of 5.7 to 8.8 cents/kWh, depending upon fuel escalation and interest rates.

Under the most likely and conservative scenarios, the cost of PV electricity exceeds the levelized cost of conventional electricity in all three cities in 1985. In the most optimistic case (3% discount, 4% fuel escalation), PV electricity is cheaper than conventional electricity only in Albuquerque. In the period 1985-1990, the cost of conventional electricity continues to escalate as the cost of PV systems falls. By 1990, the levelized cost of PV electricity is cheaper than the levelized cost of conventional electricity in all three cities in the optimistic and most likely scenarios. Under the most pessimistic scenario (8% discount, 2% fuel escalation), PV electricity is more expensive than conventional electricity in all three sites.

5.4 Conclusions

An economic analysis of the profitability of replacing conventional electricity with on-site solar PV power systems has been completed for broadcasting stations. The analyses indicate that PV power systems will prove profitable for the broadcasting market in the Southwest by the early 1980s, in the South by the mid-1980s and in the Northeast by the late 1980s, if cost predictions are met. An experimental PV power system has been in use at a radio station in Ohio since August 1979, operating as predicted and serving as a useful example for projecting costs to the future.

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APPENDIX

This appendix contains tables for each of the three locations, each array and battery size, and each of the three cost scenario cases for daytime only and 24-hour station operation. The percent of the annual energy load furnished by the array and the percent surplus energy are listed. These values were used to produce the curves in Fig. 3 in the report.

For each cost scenario case, the year each array and battery size is economical is listed, along with the net dollar (in thousands) savings for the 20-year lifetime of the system.

The years marked with an asterisk (*) show the largest system for that year of economic viability and those marked with a plus (+) show the most profitable system for that year. These values were used to produce the curves in Figs. 4 and 5. The annual energy consumed for the 4-kW fixed load used in the study was 17.5 MWH for daytime and 35.0 MWH for 24-hour operation. The results are presented as a normalized percent of the annual load.

BOSTON DAYTIME

Array kWp	Battery kWh	Array % of Load	Surplus % of Load	Case I		Case II		Case III	
				Year	Net \$K	Year	Net \$K	Year	Net \$K
6	10	43.4	.2	1983	.4				
				1985	4.5	1986*+	.2		
				1990	9.9	1990	2.7	1990*+	.1
				1995	13.7	1995	4.6	1995	1.7
				2000	17.7	2000	6.4	2000	3.3
	20	43.7	0	1983	.4				
				1985	4.5	1986	.03		
				1990	9.9	1990	2.5	1991	.2
				1995	13.7	1995	4.4	1995	1.5
				2000	17.8	2000	6.3	2000	3.1
	40	43.7	0	1983	.4				
				1985	4.4	1987	.5		
				1990	9.8	1990	2.1	1993	.2
				1995	13.6	1995	4.0	1995	.8
				2000	17.7	2000	5.9	2000	2.5
	80	43.6	0	1984	2.3				
				1985	4.4	1988	.3		
				1990	9.5	1990	1.3		
				1995	13.2	1995	3.2	1997	.2
				2000	17.4	2000	5.0	2000	1.2
8	10	52.8	5.1	1984	2.3				
				1985	4.6	1987	.4		
				1990	11.5	1990	2.6	1992	.1
				1995	16.1	1995	4.9	1995	1.2
				2000	21.1	2000	7.1	2000	3.2
	20	56.8	1.6	1983	.3				
				1985	5.7	1987	1.0		
				1990	12.8	1990	3.2	1991*	.2
				1995	17.7	1995	5.7	1995+	1.8
				2000	23.1	2000	8.1	2000+	4.0
	40	58.6	.2	1983+	.6				
				1985	6.0	1987	1.0		
				1990	13.2	1990+	3.2	1992*	.3
				1995	18.3	1995	5.7	1995	1.6
				2000	23.8	2000	8.2	2000	3.8
	80	58.9	0	1983*	.4				
				1985	5.8	1987	.2		
				1990	13.1	1990	2.4		
				1995	18.2	1995	5.0	1995	.4
				2000	23.7	2000	7.5	2000	2.7

Boston Daytime (con'd)

Array kWp	Battery kWh	Array % of Load	Surplus % of Load	Case I		Case II		Case III	
				Year	Net \$K	Year	Net \$K	Year	Net \$K
10	10	56.7	12.8	1984	.4				
				1985	3.2	1989	.5		
				1990	11.2	1990	1.2		
				1995	16.3	1995	3.8	1999	.1
				2000	21.7	2000	6.2	2000	.5
	20	63.0	7.9	1984	2.1				
				1985	4.9	1988	.8		
				1990	13.3	1990	2.4	1994	.1
				1995	18.9	1995	5.2	1995	.6
				2000	24.8	2000	7.9	2000	3.0
	40	68.2	3.5	1984	3.3				
				1985	6.2	1987	.4		
				1990	14.9	1990	3.1	1993*	.2
				1995	20.9	1995+	6.1	1995	1.1
				2000	27.3	2000	9.0	2000	3.7
	80	70.7	1.2	1984+	3.7				
				1985	6.6	1987*	.1		
				1990	15.5	1990	2.8		
				1995	21.6	1995	5.9	1995*	.2
				2000	28.3	2000	8.9	2000	2.9
12	10	59.1	20.9	1985	1.3				
				1990	10.4	1991	.2		
				1995	15.8	1995	2.3		
				2000	21.4	2000	4.8		
				20	66.7	16.5	1984	.1	
	1985	3.4	1989				.2		
	1990	12.9	1990				1.0		
	1995	18.9	1995				4.0	1998	.2
	2000	25.2	2000				6.9	2000	1.3
	40	73.9	10.6	1984	1.9				
				1985	5.2	1988	.3		
				1990	15.2	1990	2.1		
				1995	21.8	1995	5.4	1996	.3
				2000	28.8	2000	8.6	2000	2.6
	80	78.7	6.3	1984	2.9				
				1985	6.3	1988*	.5		
				1990	16.6	1990	2.4		
				1995	23.5	1995	5.8	1996*	.2
				2000	30.9	2000+	9.2	2000	2.6
	150	81.6	3.7	1984	3.2				
1985+				6.6	1989*	.6			
1990				17.0	1990	1.5			
1995				24.2	1995	5.1	1999*	.5	
2000				31.9	2000	8.6	2000	1.2	

Boston Daytime (con'd)

Array kWp	Battery kWh	Array % of Load	Surplus % of Load	Case I		Case II		Case III		
				Year	Net \$K	Year	Net \$K	Year	Net \$K	
15	10	61.5	31.9	1986	1.0					
				1990	8.7					
				1995	14.6	1996	.2			
				2000	20.4	2000	2.4			
	20	69.8	30.3		1985	.5				
					1990	11.5	1993	.4		
					1995	18.0	1995	1.6		
					2000	24.7	2000	4.7		
	40	78.1	25.0		1985	2.6				
					1990	14.2	1991	.6		
					1995	21.3	1995	3.4		
					2000	28.8	2000	6.7		
	80	84.9	19.1		1984	.1				
					1985	4.2				
					1990	16.2	1990*	.4		
					1995	23.8	1995	4.2		
					2000	31.9	2000	7.9	2000*	.3
					1984*	.9				
	150	89.4	15.1		1985	5.0				
					1990+	17.3	1991*	.8		
1995+					25.2	1995	3.9			
2000+					33.7	2000	7.8			
20	20	73.0	54.9	1987	2.0					
				1990	8.5					
				1995	15.6					
				2000	22.7	2000	.4			
	40	81.7	54.6		1986	1.1				
					1990	11.4				
					1995	19.2	1997	.4		
					2000	27.0	2000	2.5		
	80	88.5	50.8		1986	2.8				
					1990	13.4				
					1995	21.7	1996	.6		
					2000	30.2	2000	3.7		
	150	94.0	46.4		1986	3.9				
					1990	14.8				
					1995	23.5	1996*	.6		
					2000	32.4	2000	3.9		
	300	95.6	44.8		1986*	3.3				
					1990	14.3				
					1995	23.1	1999*	.4		
					2000	32.2	2000	1.2		

BOSTON 24-HOUR

Array kWp	Battery kWh	Array % of Load	Surplus % of Load	Case I		Case II		Case III	
				Year	Net \$K	Year	Net \$K	Year	Net \$K
8	10	27.6	2.7	1984	2.3				
				1985	4.6	1987	.4		
				1990	11.5	1990	2.6	1992	.1
				1995	16.1	1995	4.9	1995	1.2
				2000	21.1	2000	7.1	2000	3.2
	20	29.7	.8	1983	.3				
				1985	5.7	1987	1.0		
				1990	12.8	1990	3.2	1991*+	.2
				1995	17.7	1995	5.7	1995+	1.8
				2000	23.1	2000	8.1	2000	4.0
	40	30.6	0	1983+	.6				
				1985	6.0	1987+	1.0		
				1990	13.3	1990	3.2	1992	.3
				1995	18.4	1995	5.8	1995	1.6
				2000	23.9	2000	8.3	2000	3.8
	80	30.7	0	1983	.3				
				1985	5.8	1987	.2		
				1990	13.0	1990	2.4		
				1995	18.1	1995	4.9	1995	.4
				2000	23.7	2000	7.4	2000	2.6
10	10	29.6	6.7	1984	.4				
				1985	3.2	1989	.5		
				1990	11.2	1990	1.2		
				1995	16.3	1995	3.8	1997	.3
				2000	21.7	2000	6.2	2000	1.6
	20	33.0	4.0	1984	2.1				
				1985	4.9	1988	.9		
				1990	13.4	1990	2.4	1994	.2
				1995	18.9	1995	5.2	1995	.6
				2000	24.9	2000	7.9	2000	3.1
	40	36.7	.5	1983	.04				
				1985	6.8	1987	.9		
				1990	15.7	1990	3.6	1992*	.1
				1995	21.8	1995	6.6	1995	1.7
				2000	28.4	2000	9.6	2000	4.3
	80	37.5	0	1983*	.1				
				1985	7.0	1987	.3		
				1990	15.9	1990	3.1	1994	.2
				1995	22.1	1995	6.2	1995	.7
				2000	28.9	2000	9.2	2000	3.4

Boston 24-Hour (con'd)

Array kWp	Battery kWh	Array % of Load	Surplus % of Load	Case I		Case II		Case III	
				Year	Net \$K	Year	Net \$K	Year	Net \$K
12	20	34.9	8.4	1984	.2				
				1985	3.4	1989	.2		
				1990	13.0	1990	1.0		
				1995	19.0	1995	4.1	1998	.3
				2000	25.3	2000	6.9	2000	1.3
	40	41.1	2.7	1984	3.2				
				1985	6.6	1987	.03		
				1990	16.9	1990	3.2	1994	.3
				1995	23.8	1995	6.7	1995	.9
				2000	31.2	2000	10.0	2000	3.9
	80	44.1	0	1984	4.5				
				1985	7.9	1987*	.4		
				1990	18.6	1990	3.6	1994	.4
				1995	26.0	1995	7.3	1995	1.0
				2000	33.9	2000	10.9	2000	4.2
150	44.3	0	1984	4.1					
			1985	7.5	1988	.3			
			1990	18.2	1990	2.3			
			1995	25.6	1995	6.0	1997	.1	
			2000	33.6	2000	9.6	2000	2.1	
15	20	36.6	15.6	1985	.5				
				1990	11.6	1993	.5		
				1995	18.1	1995	1.7		
				2000	24.8	2000	4.7		
				1984	.5				
	40	44.4	9.0	1984	.5				
				1985	4.6	1989	.3		
				1990	16.6	1990	1.3		
				1995	24.2	1995	5.1	1998	.2
				2000	32.3	2000	8.8	2000	1.6
	80	52.9	.8	1984	4.6				
				1985	8.9	1988	1.6		
				1990	21.9	1990+	4.0	1994*	.1
				1995	30.8	1995	8.5	1995	.8
				2000	40.3	2000	12.8	2000	4.7
150	54.1	0	1984	4.7					
			1985	9.0	1988	.6			
			1990	22.2	1990	3.1			
			1995	31.2	1995	7.6	1997	.7	
			2000	41.0	2000	12.0	2000+	3.2	

Boston 24-Hour (con'd)

Array kWp	Battery kWh	Array % of Load	Surplus % of Load	Case I		Case II		Case III	
				Year	Net \$K	Year	Net \$K	Year	Net \$K
20	20	38.3	28.3	1987	2.1				
				1990	8.6				
				1995	15.8				
				2000	22.8	2000	.5		
	40	47.7	23.0	1985	.02				
				1990	14.7	1994	.7		
				1995	23.2	1995	1.5		
				2000	31.9	2000	5.4		
	80	62.4	9.1	1984	2.1				
				1985	7.6	1989	1.1		
				1990	24.0	1990	2.5		
				1995	34.7	1995	7.6	1997	.1
				2000	46.0	2000	13.0	2000	2.9
	150	69.1	3.0	1984	5.0				
				1985	10.7	1988*	.6		
				1990	27.9	1990	3.8		
				1995	39.5	1995+	9.6	1996*	.07
				2000	52.0	2000+	15.3	2000	4.1
	300	71.5	.8	1984+	5.2				
				1985+	10.9	1989*	.2		
1990				28.4	1990	1.7			
1995				40.3	1995	7.7			
2000				53.2	2000	13.5	2000	.6	
25	20	39.3	39.4	1988	.7				
				1990	5.2				
				1995	12.9				
				2000	20.2				
	40	49.0	37.5	1987	3.2				
				1990	11.4				
				1995	20.5	1999	.04		
				2000	29.5	2000	.9		
	80	66.4	22.4	1985	3.5				
				1990	22.6	1991	.002		
				1995	34.2	1995	4.5		
				2000	46.3	2000	10.0		
	150	76.7	13.1	1984	1.5				
				1985	8.4				
				1990	28.8	1990	1.5		
				1995	41.9	1995	8.1	1999*	.2
				2000	55.8	2000	14.4	2000	1.4
	300	82.0	8.0	1984*	3.2				
				1985	10.2				
				1990+	31.2	1990*	.6		
1995+				45.1	1995	7.6			
2000+				60.0	2000	14.3			

Boston 24-Hour (con'd)

Array kWp	Battery kWh	Array % of Load	Surplus % of Load	Case I		Case II		Case III		
				Year	Net \$K	Year	Net \$K	Year	Net \$K	
35	40	50.0	64.6	1989	1.2					
				1990	4.0					
				1995	13.9					
				2000	23.3					
	80	70.1	51.8	51.8	1987	5.2				
					1990	16.9				
					1995	29.8	1999	.4		
					2000	42.7	2000	1.6		
	150	81.5	43.1	43.1	1985	5.2				
					1990	23.8				
					1995	38.4	1996	1.2		
					2000	53.3	2000	6.6		
300	89.1	36.8	36.8	1985*	1.4					
				1990	27.7					
				1995	43.4	1995*	.5			
				2000	59.7	2000	7.9			

FORT WORTH DAYTIME

Array kWp	Battery kWh	Array % of Load	Surplus % of Load	Case I		Case II		Case III	
				Year	Net \$K	Year	Net \$K	Year	Net \$K
6	10	54.8	.2	1983	3.0				
				1985	7.3	1985+	1.0		
				1990	13.3	1990	4.9	1990+	.3
				1995	17.9	1995	7.2	1995	2.0
				2000	22.9	2000	9.4	2000	3.7
	20	55.1	0	1983	3.0				
				1985	7.3	1985	.9		
				1990	13.4	1990	4.8	1990*	.1
				1995	17.9	1995	7.0	1995	1.7
				2000	23.0	2000	9.3	2000	3.4
	40	55.2	0	1983	2.9				
				1985	7.2	1985	.5		
				1990	13.3	1990	4.4	1992	.1
				1995	17.8	1995	6.6	1995	1.1
				2000	22.9	2000	8.9	2000	2.8
	80	55.2	0	1983	2.6				
				1985	6.9	1986	.8		
				1990	13.0	1990	3.5		
				1995	17.5	1995	5.8	1996	.2
				2000	22.6	2000	8.1	2000	1.5
8	10	64.8	6.8	1983	2.0				
				1985	7.5	1986	1.4		
				1990	15.1	1990	4.9	1990	0
				1995	20.5	1995	7.6	1995	1.2
				2000	26.5	2000	10.2	2000	3.2
	20	70.8	2.0	1983	3.4				
				1985	9.1	1985	.8		
				1990	17.0	1990	5.9	1991	.3
				1995	22.8	1995	8.8	1995+	2.0
				2000	29.3	2000	11.8	2000+	4.2
	40	73.3	.3	1983+	3.9				
				1985	9.7	1985	.8		
				1990	17.7	1990+	6.1	1991*	.1
				1995	23.8	1995	9.1	1995	1.8
				2000	30.5	2000	12.1	2000	4.1
	80	73.9	.1	1983	3.8				
				1985	9.5	1985*	.1		
				1990	17.6	1990	5.4	1994	.3
				1995	23.7	1995	8.4	1995	.7
				2000	30.5	2000	11.4	2000	3.0

Fort Worth Daytime (con'd)

Array kWp	Battery kWh	Array % of Load	Surplus % of Load	Case I		Case II		Case III	
				Year	Net \$K	Year	Net \$K	Year	Net \$K
10	10	67.9	16.6	1984	3.0				
				1985	5.8	1987	.6		
				1990	14.4	1990	3.3		
				1995	20.3	1995	6.2	1998	.3
				2000	26.5	2000	9.0	2000	1.2
	20	76.7	10.9	1983	1.3				
				1985	8.2	1986	.8		
				1990	17.3	1990	5.0		
				1995	23.8	1995	8.2	1995	.4
				2000	30.9	2000	11.4	2000	2.8
	40	82.9	6.4	1983	2.8				
				1985	9.8	1986	1.5		
				1990	19.3	1990	5.9	1993*	0
				1995	26.2	1995	9.4	1995	1.0
				2000	33.8	2000	12.8	2000	3.5
	80	86.6	3.5	1983	3.4				
				1985+	10.5	1986*	1.4		
				1990	20.2	1990	5.9		
				1995	27.4	1995+	9.4	1995*	.4
				2000	35.3	2000+	13.0	2000	3.1
12	10	69.5	26.4	1984	.5				
				1985	3.7	1989	.6		
				1990	13.3	1990	1.4		
				1995	19.4	1995	4.5		
				2000	25.8	2000	7.4		
	20	79.4	22.5	1984	3.0				
				1985	6.4	1986	.7		
				1990	16.6	1990	3.4		
				1995	23.4	1995	6.8	1999	.2
				2000	30.7	2000	10.1	2000	.7
	40	87.5	17.3	1983	.4				
				1985	8.5	1987	1.4		
				1990	19.2	1990	4.7		
				1995	26.6	1995	8.4	1997*	.2
				2000	34.7	2000	12.0	2000	1.9
	80	92.5	13.6	1983	1.3				
				1985	9.6	1987	1.5		
				1990	20.5	1990	4.9		
				1995	28.3	1995	8.8	1998*	.5
				2000	36.8	2000	12.6	2000	1.7
150	95.8	10.5	1983*	1.6					
			1985	9.9	1987*	.7			
			1990+	21.1	1990	4.2			
			1995+	29.2	1995	8.1			
			2000+	38.0	2000	12.1	2000*	.2	

Fort Worth Daytime (con'd)

Array kWp	Battery kWh	Array % of Load	Surplus % of Load	Case I		Case II		Case III		
				Year	Net \$K	Year	Net \$K	Year	Net \$K	
15	20	8.15	39.5	1985	3.2					
				1990	14.9	1990	.5			
				1995	22.1	1995	4.1			
				2000	29.6	2000	7.5			
	40	89.8	37.4	1984	1.2					
				1985	5.3	1989	.8			
				1990	17.5	1990	1.8			
				1995	25.3	1995	5.8			
	80	94.5	35.3	2000	33.6	2000	9.5			
				1984	2.1					
				1985	6.3	1989	1.0			
				1990	18.8	1990	2.0			
	150	97.7	32.9	1995	26.9	1995	6.1			
				2000	35.7	2000	10.1			
				1984*	2.5					
1985				6.7	1989*	.2				
20	20	84.0		1990	19.3	1990	1.3			
				1995	27.8	1995	5.5			
				2000	36.8	2000	9.5			
				1986	1.3					
	40	91.9			1990	11.6				
					1995	19.4	1996	.2		
					2000	27.2	2000	3.0		
					1986	3.5				
	80	96.2			1990	14.1	1994	.3		
					1995	22.5	1995	1.0		
					2000	31.1	2000	4.9		
					1985	.4				
	150	99.0			1990	15.2	1994	.5		
					1995	23.9	1995	1.3		
					2000	32.9	2000	5.3		
1985*					.7					
300	100.0			1990	15.7					
				1995	24.6	1995*	.5			
				2000	33.8	2000	4.7			
				1986*	3.9					
2000				1990	14.9					
				1995	23.9	1998*	.1			
				2000	33.2	2000	1.8			

FORT WORTH 24-HOUR

Array kWp	Battery kWh	Array % of Load	Surplus % of Load	Case I		Case II		Case III	
				Year	Net \$K	Year	Net \$K	Year	Net \$K
6	10	27.9	.1	1983	3.0				
				1985	7.3	1985+	1.0		
				1990	13.3	1990	4.9	1990+	.3
				1995	17.9	1995	7.2	1995	2.0
				2000	22.9	2000	9.4	2000	3.7
	20	28.1	0	1983	3.1				
				1985	7.4	1985	.9		
				1990	13.4	1990	4.8	1990*	.1
				1995	18.0	1995	7.1	1995	1.7
				2000	23.0	2000	9.3	2000	3.4
	40	28.1	0	1983	2.9				
				1985	7.2	1985	.5		
1990				13.3	1990	4.4	1992	.1	
1995				17.8	1995	6.6	1995	1.1	
2000				22.9	2000	8.9	2000	2.8	
8	10	33.0	3.5	1983	2.0				
				1985	7.5	1986	1.4		
				1990	15.0	1990	4.8	1992	0
				1995	20.4	1995	7.5	1995	1.2
				2000	26.4	2000	10.2	2000	3.2
	20	36.2	.8	1983	3.5				
				1985	9.2	1985	.8		
				1990	17.1	1990	6.0	1991	.4
				1995	22.9	1995	8.9	1995+	2.0
				2000	29.5	2000	11.8	2000	4.2
	40	37.5	0	1983	4.0				
				1985	9.7	1985	.9		
1990				17.8	1990	6.1	1991*	.2	
1995				23.8	1995	9.1	1995	1.9	
2000				30.6	2000	12.2	2000	4.2	
80	37.7	0	1983	3.8					
			1985	9.6	1985	.1			
			1990	17.6	1990	5.4	1994	.3	
			1995	23.7	1995	8.4	1995	.7	
			2000	30.5	2000	11.4	2000	3.0	

Fort Worth 24-Hour (con'd)

Array kWp	Battery kWh	Array % of Load	Surplus % of Load	Case I		Case II		Case III	
				Year	Net \$K	Year	Net \$K	Year	Net \$K
10	20	39.5	5.0	1983	1.5				
				1985	8.4	1986	.9		
				1990	17.6	1990	5.2	1994	.1
				1995	24.1	1995	8.4	1995	.6
				2000	31.2	2000	11.6	2000	3.0
	40	44.9	.4	1983	4.1				
				1985	11.1	1985	.6		
				1990	21.1	1990	7.0	1992*	.4
				1995	28.3	1995	10.6	1995	1.9
				2000	36.4	2000	14.3	2000	4.7
	80	45.9	0	1983	4.3				
				1985	11.4	1985	.1		
				1990	21.4	1990	6.6	1994	.5
				1995	28.8	1995	10.3	1995	1.0
				2000	37.1	2000	14.0	2000	3.8
150	46.0	0	1983	3.9					
			1985	11.0	1986	.6			
			1990	21.0	1990	5.2			
			1995	28.4	1995	8.9	1998	.5	
			2000	36.7	2000	12.6	2000	1.7	
12	20	40.8	11.0	1984	3.2				
				1985	6.6	1987	.4		
				1990	16.9	1990	3.5		
				1995	23.7	1995	7.0	1999	.4
				2000	31.1	2000	10.3	2000	.9
	40	49.7	3.3	1983	2.9				
				1985	11.2	1986	1.6		
				1990	22.5	1990	6.8	1994	.5
				1995	30.7	1995	10.9	1995	1.0
				2000	39.6	2000	14.9	2000	4.1
	80	53.9	0	1983	4.7				
				1985	13.2	1985*	0		
				1990	25.0	1990	7.8	1993*	.1
				1995	33.7	1995	12.1	1995	1.3
				2000	43.4	2000	16.5	2000	4.6
150	54.2	0	1983	4.3					
			1985	12.8	1986	1.0			
			1990	24.7	1990	6.4			
			1995	33.5	1995	10.8	1997	.5	
			2000	43.3	2000	15.2	2000	2.5	

Fort Worth 24-Hour (con'd)

Array kWp	Battery kWh	Array % of Load	Surplus % of Load	Case I		Case II		Case III		
				Year	Net \$K	Year	Net \$K	Year	Net \$K	
15	20	41.8	19.7	1985	3.3					
				1990	15.0	1990	.6			
				1995	22.3	1995	4.3			
				2000	29.9	2000	7.7			
	40	52.5	11.8		1984	4.6				
					1985	8.9	1987	.7		
					1990	21.9	1990	4.7		
					1995	30.7	1995	9.1	1999	.6
					2000	40.2	2000	13.3	2000	1.2
	80	64.7	.6		1983	4.7				
					1985	15.2	1986	2.4		
					1990	29.6	1990	9.0	1994*	.6
					1995	40.2	1995	14.2	1995	1.3
					2000	51.9	2000	19.5	2000+	5.2
	150	66.2	0		1983	4.9				
1985					15.5	1986	1.4			
1990					30.1	1990	8.1			
1995					40.8	1995	13.5	1996	.4	
2000					52.8	2000	18.8	2000	3.6	
300	66.4	0		1983	3.9					
				1985	14.5	1987	.6			
				1990	29.1	1990	5.1			
				1995	39.9	1995	10.5			
				2000	51.9	2000	15.8			
20	20	42.4	34.5	1986	1.1					
				1990	11.4					
				1995	19.1	1997	.7			
				2000	26.9	2000	2.8			
	40	53.8	30.1		1985	3.3				
					1990	18.6	1991	.8		
					1995	28.0	1995	4.4		
					2000	37.8	2000	8.9		
	80	74.4	12.0		1983	.5				
					1985	14.1	1987	2.1		
					1990	31.9	1990	7.6		
					1995	44.3	1995	13.7	1998	.8
					2000	57.8	2000	19.8	2000	2.7
	150	84.4	3.3		1983	5.0				
					1985	18.9	1986*	1.5		
1990					37.9	1990+	10.3			
1995					51.7	1995+	17.1	1996*	.6	
2000					66.9	2000+	24.0	2000	4.8	
300	87.4	.9		1983*+	5.4					
				1985+	19.5	1987*	2.5			
				1990	38.9	1990	8.4			
				1995	53.1	1995	15.5	1999*	.3	
				2000	68.9	2000	22.6	2000	1.4	

Fort Worth 24-Hour (con'd)

Array kWp	Battery kWh	Array % of Load	Surplus % of Load	Case I		Case II		Case III		
				Year	Net \$K	Year	Net \$K	Year	Net \$K	
25	40	55.3	46.2	1986	2.6					
				1990	15.6					
				1995	25.6	1996	.8			
				2000	35.7	2000	4.5			
	80	77.3	29.5		1984	2.4				
					1985	9.3	1998	1.5		
					1990	29.7	1990	3.2		
					1995	42.9	1995	9.9		
					2000	56.9	2000	16.2		
	150	88.8	20.1		1984	7.8				
					1985	15.0	1988	2.6		
					1990	36.7	1990	6.6		
					1995	51.6	1995	14.0		
					2000	67.7	2000	21.3	2000*	0
	300	93.8	16.1		1984*	9.3				
					1985	16.6	1988*	1.4		
1990+					38.9	1990	5.6			
1995+					54.5	1995	13.3			
2000+					71.5	2000	21.0			
35	40	56.5	74.6	1988	1.5					
				1990	8.2					
				1995	19.2					
				2000	29.7					
	80	80.4	64.3		1986	5.1				
					1990	23.6				
					1995	38.0	1995	.8		
					2000	52.7	2000	7.5		
	150	91.7	58.8		1985	3.9				
					1990	30.5	1992	.3		
					1995	46.6	1995	4.9		
					2000	63.3	2000	12.5		
	300	96.8	56.8		1985*	5.5				
					1990	32.7	1993*	1.1		
					1995	49.6	1995	4.3		
					2000	67.2	2000	12.2		

ALBUQUERQUE DAYTIME

Array kWp	Battery kWh	Array % of Load	Surplus % of Load	Case I		Case II		Case III	
				Year	Net \$K	Year	Net \$K	Year	Net \$K
6	10	71.7	3.0	1982	3.5	1984	2.2		
				1985	11.5	1985	3.9	1989	.3
				1990	18.5	1990	8.2	1990	.6
				1995	24.2	1995	11.2	1995	1.8
				2000	30.6	2000	13.9	2000	2.9
	20	75.4	.1	1982+	4.3	1983+	.4		
				1985	12.5	1985+	4.3	1988*+	.1
				1990	19.6	1990	8.8	1990+	.8
				1995	25.6	1995	11.7	1995+	2.0
				2000	32.3	2000	14.7	2000+	3.1
	40	75.8	0	1982	4.2	1983*	0		
				1985	12.4	1985	4.0		
				1990	19.6	1990	8.5	1990*	.2
				1995	25.6	1995	11.4	1995	1.4
				2000	32.4	2000	14.4	2000	2.6
8	10	77.2	21.1	1982	.3				
				1985	10.5	1985	1.9		
				1990	18.7	1990	7.2		
				1995	24.9	1995	10.2	1996	.1
				2000	31.8	2000	13.4	2000	1.0
	20	87.7	13.4	1982	2.7	1984	1.4		
				1985	13.2	1985	3.6		
				1990	22.0	1990	9.2	1992	.2
				1995	29.0	1995	12.6	1995	1.0
				2000	36.9	2000	16.2	2000	2.4
	40	93.0	9.5	1982	3.8	1984	1.9		
				1985	14.5	1985	4.1		
				1990	23.6	1990+	9.9	1991*	0
				1995	31.0	1995+	13.5	1995	1.2
				2000	39.4	2000+	17.3	2000	2.6
80	95.1	7.9	1982	4.0	1984*	1.5			
			1985+	14.8	1985	3.7			
			1990+	24.0	1990	9.5			
			1995	31.6	1995	13.2	1995*	.2	
			2000	40.1	2000	17.0	2000	1.6	

Albuquerque Daytime (con'd)

Array kWp	Battery kWh	Array % of Load	Surplus % of Load	Case I		Case II		Case III	
				Year	Net \$K	Year	Net \$K	Year	Net \$K
10	20	90.5	32.3	1983	4.4				
				1985	11.5	1985	1.1		
				1990	21.3	1990	7.6		
				1995	28.7	1995	11.2		
				2000	36.8	2000	14.9	2000	.1
	40	96.7	28.9	1982	.2				
				1985	13.0	1985	1.8		
				1990	23.2	1990	8.5		
				1995	31.0	1995	12.3	1999*	.2
				2000	39.7	2000	16.2	2000	.5
	80	99.1	27.6	1982*	.5				
				1985	13.2	1985*	.4		
				1990	23.7	1990	8.1		
				1995+	31.7	1995	12.0		
				2000+	40.6	2000	16.1		
12	20	91.5	51.5	1983	1.1				
				1985	9.2	1986	.5		
				1990	20.0	1990	5.6		
				1995	27.6	1995	9.3		
				2000	35.9	2000	13.1		
	40	97.7	50.8	1983	2.4				
				1985	10.7	1986	1.3		
				1990	21.9	1990	6.5		
				1995	29.9	1995	10.4		
				2000	38.8	2000	14.4		
	80	99.3	51.5	1983	2.5				
				1985	10.9	1986*	.7		
				1990	22.2	1990	6.0		
				1995	30.3	1995	10.0		
				2000	39.2	2000	14.0		
150	100.0	51.5	1983*	2.2					
			1985	10.5	1987*	1.1			
			1990	21.9	1990	4.6			
			1995	30.1	1995	8.7			
			2000	39.1	2000	12.8			

ALBUQUERQUE 24-HOUR

Array kWp	Battery kWh	Array % of Load	Surplus % of Load	Case I		Case II		Case III	
				Year	Net \$K	Year	Net \$K	Year	Net \$K
6	10	35.8	1.5	1982	3.5	1984	2.2		
				1985	11.6	1985	8.3	1989	.3
				1990	18.5	1990	8.3	1990	.6
				1995	24.2	1995	11.0	1995	1.8
				2000	30.6	2000	13.9	2000	2.9
	20	37.6	0	1982	4.3	1983+	.4		
				1985	12.5	1985	4.3	1988*+	.1
				1990	19.6	1990	8.8	1990+	.8
				1995	25.6	1995	11.7	1995	2.0
				2000	32.3	2000	14.7	2000	3.1
	40	37.8	0	1982	4.2	1983	0		
				1985	12.4	1985	4.0		
				1990	19.6	1990	8.5	1990	.2
				1995	25.5	1995	11.4	1995	.4
				2000	32.3	2000	14.4	2000	2.5
8	10	38.7	10.4	1982	.4				
				1985	10.6	1985	1.9		
				1990	18.8	1990	7.3		
				1995	25.0	1995	10.3	1996	.1
				2000	32.0	2000	13.5	2000	1.1
	20	44.5	5.7	1982	.3	1984	1.7		
				1985	13.6	1985	3.8		
				1990	22.5	1990	9.5	1991	.1
				1995	29.6	1995	13.0	1995	1.2
				2000	37.6	2000	16.5	2000	2.6
	40	50.4	.2	1982	5.7	1983*	.3		
				1985	16.7	1985	5.6	1989*	.3
				1990	26.3	1990	11.6	1990	.7
				1995	34.2	1995	15.5	1995+	2.3
				2000	43.3	2000	19.5	2000	3.8
80	51.0	0	1982	5.6	1984	2.7			
			1985	16.7	1985	5.0			
			1990	26.4	1990	11.0	1992	.3	
			1995	34.4	1995	14.9	1995	1.2	
			2000	43.6	2000	19.1	2000	2.8	

Albuquerque 24-Hour (con'd)

Array kWp	Battery kWh	Array % of Load	Surplus % of Load	Case I		Case II		Case III		
				Year	Net \$K	Year	Net \$K	Year	Net \$K	
10	20	45.9	15.1	1983	4.7					
				1985	11.8	1985	1.4			
				1990	21.8	1990	7.9			
				1995	29.2	1995	11.5	1999	.1	
				2000	37.5	2000	15.3	2000	.4	
	40	56.9	4.7		1982	4.3	1984	2.2		
					1985	17.6	1985	5.0		
					1990	28.9	1990	12.1	1991	0
					1995	37.9	1995	16.5	1995	1.4
					2000	48.1	2000	21.1	2000	3.2
	80	62.3	0		1982	6.6	1984	3.3		
					1985	20.2	1985	6.1		
					1990	32.1	1990	13.5	1991	.2
					1995	41.9	1995	18.3	1995	1.7
					2000	53.1	2000	23.3	2000	3.6
	150	62.5	0		1982	6.2	1984	1.9		
					1985	19.8	1985	4.7		
					1990	31.7	1990	12.2		
					1995	41.6	1995	17.0	1997	.3
					2000	52.8	2000	22.0	2000	1.5
12	20	46.5	24.4	1983	1.4					
				1985	9.6	1986	.8			
				1990	20.6	1990	5.9			
				1995	28.3	1995	9.7			
				2000	36.7	2000	13.5			
	40	58.8	14.1		1982	.7				
					1985	16.1	1985	2.7		
					1990	28.5	1990	10.7		
					1995	38.0	1995	15.4	1997	0
					2000	48.6	2000	20.1	2000	1.1
	80	73.1	.2		1982	7.2	1984	3.7		
					1985	23.5	1985+	7.0		
					1990	37.5	1990	15.9	1991*	.3
					1995	49.1	1995	21.5	1995	2.1
					2000	62.2	2000	27.4	2000+	4.3
	150	73.9	0		1982	7.1	1984	2.5		
					1985	23.4	1985	5.8		
					1990	37.6	1990	14.8		
					1995	49.3	1995	20.5	1995	.1
					2000	62.5	2000	26.4	2000	2.4

Albuquerque 24-Hour (con'd)

Array kWp	Battery kWh	Array % of Load	Surplus % of Load	Case I		Case II		Case III		
				Year	Net \$K	Year	Net \$K	Year	Net \$K	
15	40	59.4	29.5	1983	2.4					
				1985	12.7	1986	1.2			
				1990	26.5	1990	7.6			
				1995	36.3	1995	12.5			
				2000	47.0	2000	17.3			
	80	82.3	7.3		1982	4.9	1984	1.8		
					1985	24.6	1985	5.9		
					1990	41.1	1990	16.4	1994*	.2
					1995	54.3	1995	22.9	1995	.7
					2000	69.1	2000	29.5	2000	3.2
	150	89.0	1.5		1982+	7.6	1984*	2.8		
					1985	21.2	1985	6.9		
					1990	45.1	1990+	17.8		
					1995	52.2	1995+	24.7	1995*	.4
					2000	75.1	2000+	31.9	2000	3.1
300	90.0	1.0		1982	7.0					
				1985+	27.2	1985	4.1			
				1990	44.7	1990	15.1			
				1995	58.9	1995	22.1			
				2000	75.1	2000	29.3			
20	40	60.3	56.6	1984	1.3					
				1985	6.8	1989	1.1			
				1990	22.9	1990	2.4			
				1995	33.3	1995	7.7			
				2000	44.2	2000	12.6			
	80	86.3	33.9		1983	6.4				
					1985	20.5	1986	3.7		
					1990	39.7	1990	12.6		
					1995	53.8	1995	19.6		
					2000	69.4	2000	26.6		
	150	97.2	24.9		1982*	.2				
					1985	25.8	1985*	2.4		
					1990+	46.3	1990	15.7		
					1995	62.0	1995	23.4		
					2000	79.5	2000	31.3		
300	98.6	24.2		1983*	11.0					
				1985	25.5	1986*	3.7			
				1990	46.2	1990	13.2			
				1995+	62.1	1995	21.0			
				2000+	79.5	2000	29.0			

Albuquerque 24-Hour (con'd)

Array kWp	Battery kWh	Array % of Load	Surplus % of Load	Case I		Case II		Case III	
				Year	Net \$K	Year	Net \$K	Year	Net \$K
25	40	60.9	80.9	1985	.8				
				1990	19.3	1993	.7		
				1995	30.1	1995	2.7		
				2000	41.2	2000	7.7		
	80	87.0	62.2	1984	7.4				
				1985	14.5	1987	.7		
				1990	36.1	1990	7.3		
				1995	50.7	1995	14.6		
				2000	66.4	2000	21.7		
	150	97.8	54.9	1983	2.7				
				1985	19.8	1987	3.4		
				1990	42.6	1990	10.4		
1995				58.8	1995	18.4			
2000				76.4	2000	26.4			
300	99.5	55.2	1983	2.4					
			1985	19.6	1987	.9			
			1990	42.7	1990	8.0			
			1995	59.1	1995	16.1			
			2000	77.0	2000	24.2			