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System Integration Issues of Residential Solar Photovoltaic Systems

March 1980

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Prepared for:

U.S. Department of Energy

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Office of Electric Energy Systems

Washington, D.C. 20461

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1.0 SUMMARY

1.1 BACKGROUND

The economic feasibility of residential solar PV electric systems with full back-up from the electric utility was analyzed in several recent studies (Refs. 1, 2). Conflicting conclusions were reached concerning the need for dedicated residential storage devices. According to Ref. 2, such storages are believed to be necessary because the interconnected electric utility is assumed to pay much less for surplus solar PV than it charges for the energy it supplies when there is insufficient insolation.

Since dedicated storage devices would add substantially to the cost of residential solar PV systems, it is important to assess whether these devices are needed or not.

1.2 STUDY OBJECTIVE

The objective of this study is to evaluate the economic effects of residential solar PV systems on the utility's revenue, capacity, and energy requirements from the electric utility's perspective and to estimate the price that it might pay for surplus energy compared to what it would charge for deficits.

To be more specific, the power and energy generated by the solar PV systems reduce the capital and operating costs that would otherwise be incurred by the utility. These "avoided costs" suggest what the utility might pay for surplus solar PV energy.

The avoided costs are evaluated under three integration hypotheses, namely:

- the utility has no system storage,
- the utility has system storage,
- the solar PV systems are supported by dedicated storage devices, the purpose of which is to minimize sales to and purchases from the utility.

1.3 RATIONALE FOR SYSTEM AND RESIDENTIAL STORAGE

The storage device(s) may be owned and operated by the utility. Such storage will be referred to as "system storage". Since the utility's primary operating objective is to minimize production cost, charging will occur at those times of the day when the cost of electric energy is low. It would be incorrect to assume that the charging energy is solely provided by the intermittent sources.

The storage devices may also be owned and operated by the owners of the solar PV sources. Such devices will be referred to as "dedicated residential storages". Their primary objective is to minimize the net amount that the solar PV owner is charged by the utility. Consequently, the operating strategy of a dedicated storage is generally to store the excess of solar PV output over load and to make up the deficit by withdrawing from storage.

The main difference between system and residential storage is that the first is controlled by the utility and the second is controlled by the solar PV owner. System storages may also be dispersed in order to achieve certain secondary objectives such as improved local reliability.

1.4 STUDY APPROACH AND ASSUMPTIONS

In order to estimate the avoided costs of the utility for the three solar PV integration schemes considered, the impact of each scheme upon the "Base" or "Without" Case thermal generation system was evaluated with the help of case studies and the savings in capital as well as operating costs of the various solar PV "with" cases were obtained. Solar PV penetrations of 1, 10, and 20% of system peak load were considered for each scheme. We will explain the "with" and "without" cases by way of an example. Let us say that we want to determine the credits due to 10% penetration of solar PV in a system under a dedicated storage integration scheme. "Without" case refers to the situation where there is zero penetration of PV and no dedicated storage. The "with" case refers to the situation where the penetration of solar PV in the utility is 10% and the homeowner has dedicated storage.

The evaluation was performed for one snapshot year (the year 2000) with the help of a generation planning model (Optimal Expansion Planning or OEP) that had been specifically developed for analyzing the economic feasibility of tidal power [3, 4] and that was subsequently applied to other intermittent resources such as solar, wind, and hydro sources [5, 6]. Reference 27 explains the details of OEP.

A synthetic electric utility of 5000 MW of summer peaking load formed the basis for the Case studies. The hourly insolation data of Albuquerque and the corresponding hourly load data that had been developed in Ref. 5 were used to model the correlated solar PV output and system load.

The yearly capital and operating cost data of the various types of thermal generating units were also taken from Ref. 5. These data originally came from EPRI Technical Assessment Guide [8].

The OEP model was used to optimize the thermal generation mix for the chosen snapshot year, first for the "without" solar PV case and thereafter for the various "with" solar PV scenarios of interest. The difference in the yearly capital and operating costs between the "with" and "without" cases constitutes the capital plus operating credits due to solar PV. This difference also equals the "avoided cost" of the utility, a term that one encounters in the electric utility regulatory literature. The optimization of the thermal generation mix is patterned after the screening curve method. However, discrete unit sizes are selected and peaking capacity is added to ensure that system reliability satisfies the specified loss-of-load-probability (LOLP) norm. The hourly operation of non-thermal generation, notably system storage and solar PV, is simulated. The net load for which the thermal mix is optimized is the difference between the original load and the non-thermal generation. In the real application, the optimum mix may not be a realization due to the following problems: (1) existing mix being a constraint, (2) load forecast and PV penetration forecast uncertainties, and (3) may not be allowed to put in optimum mix, due to environmental restrictions.

The determination of the solar PV credits for the case of system storage requires caution, because some of the credits between the original "without" storage, no solar PV and the "with" storage, solar PV cases are due to storage and some are due to solar PV. In order to allocate these credits, a "new without" case containing system storage but no solar PV was first created. Then, solar PV was introduced into this "new without" system and the credits due to solar PV were determined by comparing the "new without" and the "with" cases (note carefully that the capital cost of system storage is included in the total capital cost of the utility's generation system).

In order to estimate what price, b , the utility might pay for surplus generation and what price, s , it might charge for deficits, it is assumed that b equals the cost expressed in dollars per megawatt-hour avoided by the utility when solar PV is installed and that s (also expressed in dollars per megawatt-hour) equals the revenue required by the utility at the level of residential delivery.

Section 210 of the Public Utility Regulatory Policy Act (PURPA) (Ref. 9) was reviewed together with its recent interpretation of the California Public Utility Commission (CPUC). Available statistics on transmission and distribution (T&D) costs were used to estimate by how much the revenue requirements at the level of bulk power generation would have to be increased in order to account for T&D expenses. [7]

One important assumption made is that the optimal thermal mix formed by the generation planning model for the Base Case and the various "with" cases would in fact be implemented. Actual generation planning considers many factors above and beyond the simple cost minimization implied by the optimal mix given by OEP. Since the "with" and "without" cases are established on the same basis, and since the avoided costs are obtained by comparing the two, one may argue that the impact of secondary factors upon this study would be negligible.

Another assumption is that the individual solar PVs and their dedicated storage may be aggregated together into a single solar PV source

and a single dedicated storage device. By comparing the simulated interchanges with the utility for "individual" and "aggregated" example cases, it was verified that this assumption is valid.

1.5 RESULTS

The main results obtained for the chosen case study are summarized here. In interpreting these results, one should bear in mind the limitations such as the use of one snapshot year, a single location study, single year insolation data, screening curve approach for optimization, etc. In determining the credits due to solar PV integration, cost increases to cover items such as communication, control, protection, spinning-reserve, safety, training, etc. were not included in this study.

1. The average cost of energy, that is, the yearly capital and operating costs divided by the yearly energy delivered, is 60.2 \$/MWh for the Base Case.
2. The avoided costs for the nine "with" cases studied are summarized in Table 1.1. In the interest of conciseness, these avoided costs are expressed in dollars per megawatt-hour of gross solar energy generated or in dollars per kilowatt-year of rated solar PV. The penetration level is the ratio of rated solar PV capacity installed to yearly system peak load.

The avoided costs of the three residential storage cases are given first without considering the cost of dedicated storage (the utility perspective) and next, and for reference only, with the cost of residential storage assumed to be equal to that of utility storage.

The results shown are affected by round-off errors. The credits of solar PV are established by comparing "with"

Table 1.1 Summary of "Costs Avoided" For Solar PV-
Storage Scenarios

Penetration Level* (%)	Type of Integration	Avoided Cost **	
		\$/MWh	or \$/kW-year
1	No Storage	66	161
1	Residential Storage	65 (47.3)+	157 (113)+
1	System Storage ^{††}	71	170.5
10	No Storage	62.5	152
10	Residential Storage	60.9 (42.6) [†]	148.8 (104.2) [†]
10	System Storage ^{††}	61.69	150
20	No Storage	55.8	136
20	Residential Storage	54.9 (37.4) [†]	135 (91.4) [†]
20	System Storage ^{††}	54.7	133.7

* Penetration level of solar PV is defined as the percentage of system peak load (5000 MW).

** Avoided cost is defined as the savings in utility revenue requirements due to solar PV integration. Avoided cost does not include T&D credits.

† Numbers in the parantheses represent the PV credits after subtracting the cost of dedicated storage from the avoided costs to the utility. The cost of dedicated storage (per megawatt-hour of solar PV added to the utility system) is subtracted from the credits (also per megawatt-hour of solar PV added) due to solar PV. The result is the net credit for a megawatt-hour of PV under dedicated storage integration scheme.

†† Storage system cost already included.

and "without" cases. These cases, in turn, are characterized by a discrete mix of units; that is, OEP selects units of specified commercial capacity, such as 50 MW for peakers. These round-off errors are not believed to affect the estimated avoided cost significantly.

3. The energy and capacity credits of the three 10% penetration "with" cases are shown in Table 1.2. Since introduction of solar PV alters the optimal thermal mix as well as the energy produced by each generation category, these energy and capacity credits are given for base, intermediate, and peaking generation.
4. In order for the utility to recover its costs for T&D investment as well as its G&A expenses, it must sell energy at 23 to 29 \$/MWh more than its average cost for bulk power generation. The need to recover these costs as well as the current attitudes of the Public Utility Commissions form the basis for estimating likely ranges of the buy-back ratio.
5. Dispersed storage devices may defer T&D investments that would otherwise be required if these devices are likely to be available for supplying local power needs when the T&D system fails. These investment deferments can be translated into a credit which is of the order of 15 \$/kW-yr of dispersed storage [16, 28].
6. It may be that the fluctuating nature of insolation will be such that the thermal generation mix needs to be altered in favor of fast responding but less economical units unless system or dedicated storage is used. There is insufficient information on the magnitude and rate of change of the aggregated production of a set of solar PV dispersed over a utility's service territory to estimate the resulting departure from an optimum mix.

Table 1.2. Energy and Capacity Credits of the
Three Ten Percent Penetration Cases.

Credit is defined as (Base Case) - (With Case)

B = Base Generation; I = Intermediate Generation;
P = Peaking Generation

With Case	Capacity Credit, ⁽¹⁾ MW				Energy Credit, GWh per year			
	B	I	P	Total	B	I	P	Total
10% Solar PV, No Storage	300	0	0	300	1231.9	-13.6	3.7	1222.0
10% Solar PV, ⁽²⁾ System Storage	300	200	-200	300	1255.7	73.8	-107	1222.5
10% Solar PV, Residential Storage	300	0	50	350	1161.2	-39.7	10.3	1131.8

- (1) The integer capacity credits shown are due to the fact that the OEP solution constitutes a discrete rather than continuous generation mix.
- (2) The "without" case for system storage portion is the new Base Case that contains system storage, but no solar PV. To evaluate the capacity and energy credits due to solar PV in a utility system with system storage, we took the following approach. First, the utility capacity and energy requirements with only storage in the system was determined. After introducing PV in the system, the utility capacity and energy requirements were reevaluated. The difference in capacity and energy requirements in the two cases is credits due to PV in a system storage scheme.

1. Range of Avoided Costs. It is evident from Table 1.1 that the costs avoided by the utility do not vary drastically for the nine solar PV scenarios considered. The difference between the best (1% penetration, system storage) and the worst (20% penetration, system storage) case is 27% of the average energy cost (60.2 \$/MWh).
2. Cost of Residential Storage. It is also evident from Table 1.1 that the residential storage cases become substantially less attractive than the no storage or system storage cases once the cost of dedicated storage is included. One of the reasons for smaller solar PV credit under dedicated storage scheme is that utility peak load and residential peak load are noncoincidental. Since homeowner's strategy is to minimize his import and does not allow buy-back from the utility (this strategy is assumed in this study), the homeowner charges his batteries at times when the utility needs the solar PV generation (example: around noontime on a summer day). This results in an uneconomical use of solar PV. This does not necessarily mean that residential storage is unattractive for the owner. It does mean that under the hypothesis of single ownership, solar PV systems with dedicated storage are not justified economically. If the buy-back ratio or alternative contractual relations between the utility and the owner are such that dedicated storage is economically justified, then the regulatory environment does not promote a least cost solution to the community, as it should. It should also be pointed out that often the homeowner has access to lower cost money than the utility, thereby introducing a subsidy into the economics of dedicated storage.
3. Energy and Capacity Credits of Solar PV. Table 1.2 shows how solar PV alters the optimum mix and the fuel requirements of base, intermediate, and peaking generation. It is seen that

the major impact of introducing 500 MW of solar PV is to reduce the system's base capacity and its requirements for base fuel. The rationale for solar PV reducing base capacity, as reported in Table 1.2, can be explained as follows: The hourly solar PV output is subtracted from the original hourly load (OL), see Figure 1-1, to obtain the residual load (RL). Since the system peak load and the solar peak output are not guaranteed to be coincidental, the peak load may not be reduced. Actual comparison of system load data and solar generation data for a number of days showed that the solar generation peak and the system load peak were 4 to 6 hours out of phase. Hence the system peak load will not decrease as much as the non-peaking loads. Since the reduction in system load due to the introduction of solar PV occurs more during the non-peaking hours, the capacity credits are in non-peaking generation. This result is also explained by Figures 1-1a and 1-1b. These figures display the screening curve for determining the base (B) and non-base (NB) capacity requirements. The intersection of the B and NB cost curves determine the capacity factor (number of operation hours) above which base technology is cheaper to install and below which non-base technology is a better choice. Using this capacity factor and the load duration curves of Figure 1-1a, the base capacity requirements for the OL and the base capacity requirements for the RL (load after subtracting the solar PV output) are designated by B_o and B_n , respectively. Since $B_o > B_n$, the base capacity requirement in the presence of solar PV is reduced by $\Delta B = B_o - B_n$. Both the capacity and energy requirements of the liquid fueled units (intermediate and peak) are relatively unchanged. In the system storage case, some peaking capacity and energy are replaced by intermediate capacity and energy, because system storage generates during the peak load.

FIGURE 1-1. Determination of Capacity Requirements With and Without Solar Generation Using the Screening Curve Approach.

The energy displaced for the case of dedicated storage is reduced by 90 GWh compared to the no storage case to account for the round-trip inefficiency.

4. Buy-Back Ratio. The notion of the buy-back ratio is sometimes used to characterize the financial transactions between the utility and the solar PV owners. The buy-back ratio is defined as the ratio of the price (reduced to mills per kilowatt-hour or dollars per megawatt-hour) at which the utility buys electric energy from the solar PV owner to the price (also reduced to mills per kilowatt-hour) at which the utility sells the electric energy to the solar PV owner. The notion is simplistic, since transactions typically involve capacity and energy charges, yet useful to discuss merits of customer-owned generation and storage schemes.

The PURPA Act (Section 210) specifies that the utility must offer to purchase electric energy from any qualified small power production facility and that the rates for such purchase shall be just and reasonable to the electric consumers of the electric utility of alternative electric energy.

Much latitude of interpretation is left to the State Public Utility Commissions. The CPUC interprets the Act as follows:

The utility must offer to buy either the surplus generation or all of the generation, at the owner's option. The latter case is termed "simultaneous buy-sell".

The utility must pay the full incremental cost with respect to energy and capacity, for the purchased energy.

The utility must supply energy at the filed rate, which reflects the average cost of delivered energy.

The CPUC recognizes that this incremental cost may exceed the filed rate. This means that the buy-back ratio could exceed one, in which case dedicated storage would have no economic justification. The reason why the filed rate may be less than the avoided cost is that the older generating units and fuel supply contracts tend to be less expensive and therefore, reduce the average cost of energy upon which the filed rate is based.

5. Solar PV Owner's Perspective. If the buy-back ratio exceeds one, the owner should accept the simultaneous buy-sell option if offered. Dedicated storage together with the "surplus only" option may be justified if the buy-back ratio is sufficiently low to compensate for round-trip inefficiency and the prorated capital cost of the storage device itself. "Surplus only" refers to the situation in which the utility buys only the solar energy in excess of the homeowner's load.
6. T&D Credits. Dispersed storage devices may qualify for a T&D investment deferral credit of the general order of 15 \$/kW-yr if they can be counted on to unload the T&D circuits in the event of T&D outages [16, 28]. This credit would apply to utility controlled dispersed storage, essentially system storage deployed throughout the service territory, and possibly to dedicated storage if the owner were willing to relinquish control during emergencies.
7. Spinning-Reserve Requirement. Even though the possible additional costs for spinning-reserve and load-following capability that may be required by solar PV introduction cannot be estimated for lack of data on the magnitude and rate of change of a multiplicity of solar PV devices, this is not believed to constitute a major impediment nor to be an

important justification for dedicated storage. If, under pessimistic assumptions, the utility without system storage could not absorb the solar PV output fluctuations, substantial system storage could be added at essentially no economic penalty (compare the no storage and system storage cases of Table 1.1). One kilowatt of system storage can provide up to 2 kW of spinning-reserve and load-following capability, depending on its current mode of operation.

8. Metering of Capacity and Energy Credit. Exactly how a residential solar PV owner would be credited for his capacity and energy contribution remains an unanswered question, at present, even though the intent may well be to reimburse him for the full avoided cost. Real-time calculation of the energy credit, which depends on the utility's incremental operating cost, appears impractical and may have to be approximated by a small number of time-of-day rates which equal the expected incremental cost for that time of the day and season. The capacity credit obtained by OEP for the aggregated solar PV devices differs significantly from the customary notion of an individual source which may be classified as firm or non-firm. According to OEP, 1 kW of solar PV would qualify for a capacity credit of 0.5 kW (see the 10% penetration, no storage case), because the 500 MW of solar PV reduce the required thermal capacity by 250 MW at constant system LOLP. Utilities that are used to the concept of a firm source may view this concept of a partial capacity credit with skepticism. Yet, allocating a partial credit to an intermittent source seems to be a very logical approach in assigning capacity values to non-utility owned sources, as required by PURPA 1978 [9].

2.0 PROBLEM DESCRIPTION

The question addressed was the evaluation of economic effects of residential solar PV electric systems on the utility's revenue requirements from the utility's perspective and estimation of the buyback ratio. Specifically, the integration of residential solar PV electric systems using three different schemes was to be considered. The schemes used in the evaluation are:

(1) Residential Solar PV Without Storage. In this scheme, the utility was willing to buy residential customers' extra solar PV energy during any time interval that residents' PV output exceeded the residential load. The utility treated the solar PV energy as part of its own generation and gave priority to the utilization of the energy to serve the system load. The utility's residual load (load after utilizing solar PV energy) was served by the utility's conventional technology. The utility did include the residential solar PV energy system in the generation planning process, that is, utility's decision on conventional technology was based on the expected solar PV energy that was going to be made available to the utility.

(2) Integration of Residential Solar PV Electric Systems to the Utility With System Storage. This case addressed the question of integration of solar PV with the utility with storage. The solar PV energy system was considered part of the utility's generation and the utility can use it to serve its load or charge (pump) its storage unit.

(3) Residential Solar PV With Residential Storage

(a) Dedicated residential storage addresses the question of integrating the residential solar PV energy system to the utility in a manner to minimize the interaction between the utility and the residential customer. The residential customer does not charge his storage from the utility grid. The residential customer uses his solar PV energy to serve his load. Whenever he has more PV energy than he needs, he charges his battery. When he does not have sufficient solar PV energy to serve his load, he discharges the battery. The customer chooses the amount of his residential storage so that he can store the "extra" solar PV energy at times he cannot use all of the energy.

(b) Residential storage under utility control would be another way of managing residential storage. The objective of the utility's control over residential storage is to charge or discharge the battery based on system load. This case is similar, with minor differences, to the system storage case; therefore, this case will be evaluated by the system storage case.

In order to address the above three integration schemes, different penetration levels of residential solar PV energy were considered. The penetration level of solar PV was defined as the percentage of rated solar PV capacity to the system's yearly peak load, instead of the percentage of system generation. This approach was used because solar PV was included in the planning process and as such, the system generation mix is not known in advance. The penetration levels considered were:

- (1) 1% penetration of solar PV,
- (2) 10% penetration of solar PV, and
- (3) 20% penetration of solar PV.

The utility revenue requirements for each integration scheme and the given solar PV penetration level were compared to the revenue requirements of the case without solar PV and storage (the Base Case), to evaluate the savings due to solar PV under different integration schemes. For the case with system storage, the savings due to storage alone was subtracted from the savings due to solar PV plus storage to determine the savings due to solar PV energy alone.

3.0 DESCRIPTION OF CASE STUDY APPROACH

To study the economic contribution of residential solar PV under different integration schemes, that is without storage, with residential storage or system storage, the utility revenue requirements for the different schemes were compared to the case with no solar PV (Base Case). For all cases, LOLP of one day in ten years was used as an acceptable reliability level. In this section, the description of each of these cases is given along with the explanation of the approach for each case.

3.1 BASE CASE — NO SOLAR PV OR STORAGE

This case evaluated the utility's revenue requirements when there were no solar PV or storage in the system. The load data described in subsection 4.1 and the generation data in Table 4.4 were input to the Optimum Expansion Planning (OEP) model. The OEP program evaluated the capacity requirements of different technologies for a snapshot year (year 2000 in this case). It calculated the operating and investment cost of adding the required capacity to the system. The results of this case study are tabulated in Table 3.1. In this report, Base Case always refers to this particular run. These revenue requirements were compared to those of the cases with solar PV to identify solar PV credits.

3.2 SOLAR PV WITHOUT STORAGE

For each of the three solar PV penetration levels, the OEP was run without fixing the base and intermediate generation. Actually, for each of the three penetration levels, computer runs where the base and intermediate generation of the Base Case was fixed, were made and compared with the case in which the mix was reoptimized. The results showed that for 10 and 20% penetration levels, which are relatively high penetrations of solar PV, the mix should have been reoptimized. For a 1% penetration case, the results were similar to the case in which the base and intermediate generation was fixed. Therefore, in this analysis, the case which reoptimized the base and intermediate generation was used. The capacity and conventional technology energy requirements in each of the three penetration levels

TABLE 3.1 Base Case System Without Solar PV and Without Storage.

1. Capacity Requirements	=	6250 MW
Fixed Charges/Year	=	663128 K\$
Fixed O&M/Year	=	<u>27960 K\$</u>
Total Fixed Charges/Year	=	691088 K\$
2. Energy Requirement (Load)	=	23405067 MWh
Fuel Costs	=	666972 K\$
Variable O&M Costs	=	49976 K\$
Total Variable Costs	=	716948 K\$
3. Total System Costs	=	1408036 K\$
Revenue Requirements	=	60.2 \$/MWh

were compared to the Base Case to evaluate the economic savings of the solar PV. The results are presented in subsection 5.1.

3.3 SOLAR PV WITH SYSTEM STORAGE

For the purpose of evaluating the economic benefits of residential solar PV energy for the utility with system storage, a case with storage but without solar PV (New Base Case) was needed first. A computer run with system storage but with no solar PV was made. The revenue, energy, and capacity requirements in this case were compared to those of the Base Case. The results of this comparison were the benefits of system storage alone (a New Base Case).

In order to find the savings due to system storage and solar PV for the different penetrations of solar PV, three computer runs of OEP (one for each penetration level and system storage) were made. The results of each penetration level were compared to the Base Case to identify the savings due to solar PV plus system storage.

For each of the three penetration levels, the savings due to storage and solar PV were compared to those of system storage alone (New Base Case). The results of this comparison are the savings due to solar PV in the system with storage. The results are presented in subsection 5.3.

3.4 SOLAR PV WITH RESIDENTIAL DEDICATED STORAGE

After introducing solar PV in the utility system, the generation mix requirement for the year 2000 was reoptimized for all three penetration levels of solar PV. Solar PV in each of the three penetration levels modified by the residential storage-policy aimed to minimize the sell-back to the utility was also input to the OEP model. The results of each run were compared to those of the Base Case and the savings due to solar PV plus residential dedicated storage were obtained. For results see subsection 5.2.

4.0 SYSTEM CHARACTERIZATION

4.1 SYSTEM LOAD

The EPRI Scenario E synthetic utility data [10] formed the basic system load data in this study. The data were specified hourly for a typical week in each of three seasons: Spring-Fall, Summer, and Winter. The hourly loads were given relative to the weekly peak. The monthly peak was given in per unit of yearly peak load. The hourly data and monthly peak data were combined with a system peak load to establish nominal hourly load data for the entire year. The system's peak load was 5000 MW. Subsequently, the hourly load was adjusted in such a way as to incorporate the correlation with temperatures. The temperature data were for Albuquerque, New Mexico [5]. Figure 4-1 shows the load data for a typical weekday.

4.2 RESIDENTIAL LOAD

Also shown in Figure 4-1 is the shape of the residential load curve for a peak day. In this study, four seasonal normalized residential load shapes were used; one for each season: Spring, Summer, Fall, and Winter. For each day of the year, the system peak load was determined and depending on the day in the particular season it fell on, the corresponding residential load shape was used to calculate hourly residential load component for that day. The residential load shapes are used to operate the residential dedicated storage.

4.3 SYSTEM AND RESIDENTIAL STORAGE

4.3.1 System Storage

To calculate the amount of system storage for the use in this project, the results from the Decentralized Energy Technology (DET) Integration Assessment Study was used [5]. In the DET study, the following steps were involved in determining the amount of system storage:

FIGURE 4-1. System Load, Residential Load and Solar PV,
Normalized to Peak Load of the Year, For a Peak Day.

- Optimize the capacity and duration of storage in the utility system without DET,
- Add the DET generation and reoptimize the amount of storage, and
- Compare the results to determine the net benefit.

Table 4.1 shows the total annual utility system costs for several base cases with different amounts of pumped hydro system storage. The total annual costs shown include the annualized capital cost of the pumped storage based on Bechtel's estimated capital cost of 327 \$/kW and a 15% fixed charge rate [11]. As shown in Table 4.1, the lowest total costs for the Base Case were achieved with 500 MW/8h of system storage. The cases in Table 4.1 were all based on a nominal 10% peak penetration; 500 MW of peak output in a 5,000 MW peak system. For these cases, the difference in total annual costs compared with the Base Case with Optimum storage are shown in the far right-hand column of the table as total annual savings. The total annual savings, 68.6 million dollars, were greatest for 500 MW/8h of storage. Also for the Base Case, the 500 MW/8h storage gave the minimum revenue requirements, implying that 500 MW/8h storage was the "optimum" amount of storage for this system. Therefore, 500 MW/8h system storage was used for the case studies with system storage.

4.3.2 Residential Storage

The amount of residential storage in this study was determined based on the objective that a household with solar PV would use as little energy from the utility as possible — as little interaction with the utility as possible. Table 4.2 gives the amount of storage used in different penetration levels. The cost of residential storage for the sake of comparison and lack of accurate estimations, was assumed to be 327 \$/kW. The annual cost of storage would be about 49 \$/kW.

**Table 4.1 Benefit of Integrating DETs into a Utility System
Storage (Summer Peaking Load Data)***

	MW Storage (8 hour)	OEP Cost (10 ⁶ \$)	Storage Cost ¹ (10 ⁶ \$)	Total Cost (10 ⁶ \$)	Savings (10 ⁶ \$)
Base Case without DET	400	1352.4	19.7	1372.1	
	500	1345.1	24.5	1369.6	
	750	1337.1	36.8	1373.9	
	1000	1336.5	49.0	1385.5	
Flat Plate PV Cases ² Albuquerque, NM	400	1282.8	19.7	1302.5	67.1
	500	1276.5	24.5	1301.0	68.6
	625	1270.8	30.7	1301.5	68.1
	750	1273.0	36.8	1309.8	59.8
	850	1271.7	41.7	1313.4	56.2
	1000	1271.8	49.1	1320.9	48.7

* From Reference [5].

¹ Pumped hydro capital cost in 1979 \$ = 327/kW based on estimates by Bechtel in "Energy Storage Evaluation Methods", January 1978.

² Based on a penetration of 100,000 five kilowatts peak output photovoltaic systems. System peak load = 5000 MW.

Table 4.2. Residential Storage Capacity and Rated Discharge.

Penetration of Solar PV	Discharge Rate	Hours of Storage
1%	45 MW	4
10%	453 MW	4
20%	875 MW	4

4.4 SOLAR PV DATA

The hourly power output of a residential flat-plate collector PV system was simulated for Albuquerque, New Mexico over a one year period [5]. The residential PV system parameters are given in Table 4.3. The performance model used for flat-plate array of PV cells used here were based on Refs. 12 and 13. Solar PV output shape for a summer day is shown in Figure 4-1.

4.5 UTILITY SYSTEM DATA

The scenarios used in this study are viewed as taking place from the year 2000 to 2030. For the purpose of this study, 1979 dollars were used. The following expresses the assumptions made for this analysis.

(a) Fuel Costs

- An inflation rate of 8.5% is used to convert these prices from 1977 prices to 1979 dollars.
- Up to the year 2000, the fuel costs are escalated as in Ref. 8.

TABLE 4.3 Residential PV System Parameters

Cell Type	Silicon
Cell Area	50 M ²
Cell Efficiency at 28°C	12%
Inverter Efficiency	87%
Cell Efficiency Temperature Coefficient	0.005/°C
Site Latitude	35°N
Collector Tilt	20° Facing South

- Beyond the year 2000, the levelizing factor, L_f , is used to levelize the fuel costs. (See Table 4.4.)

(b) Capital Costs

- An 8.5% inflation rate is used to convert 1977 costs to 1979 dollars.
- No escalation or inflation rate between 1979 and 2000 is used.
- A fixed charge rate of 15% is used to levelize it beyond 2000.

(c) Fixed O&M Costs

- An 8.5% inflation rate is used to convert 1977 costs to 1979 dollars.
- No escalation and inflation rate is used between 1979 and 2000.
- Inflation is used as apparent escalation to levelize the costs between the year 2000 and 2030.

(d) Variable O&M Costs

- Inflation rate of 8.5% is used to convert 1977 costs to 1979 dollars.
- No escalation or inflation rate is used between 1979 and 2000.
- From 2000 to 2030 an apparent escalation rate of 6% is used to levelize the O&M cost.

The data for conventional technologies used in this study are tabulated in Table 4.4.

4.6 UTILITY SYSTEM MODELS

SCI has a set of models called OEP explicitly designed to evaluate economics of unconventional technologies. The major submodels in OEP are WISO, OPTMIX, TCC, and FASCOS (see Figure 4-2). WISO determines the contribution of intermittent generation and storage facilities to

Table 4.4 Economic Data

Generation Type	Capital Cost \$/kW	Heat Rate (Btu/kWh)	Fuel Cost \$/MBtu	Fuel Cost \$/MWh	Var. O&M \$/MWh	Total Var. Cost \$/MWh	Fixed O&M \$/kW-yr
Nuclear (PWR)	950.0	10,400	2.48	25.79	1.53	27.32	6.1
Coal	888.6	10,400	2.41	25.06	3.57	28.63	5.5
Combined Cycle	382.5	8,800	9.16	80.61	2.82	83.43	2.7
Combustion Turbine	188.3	14,000	9.49	132.86	4.55	137.41	1.1

NOTES:

1. Fixed charge rate (including tax preferences) = 15%.
2. Interest rate = 10% (discount rate).
3. Inflation rate = 6%.
4. Costs are given in 1979 dollars.
5. Fuel and variable O&M costs are levelized, using L_f below, for the period 2000 to 2030.

$$L_f = \text{Levelizing factor} = \text{CRF}(r, N) \cdot K(1 - K^N) / (1 - K)$$

where:

N = Book life = 30 years used in this study.

e = apparent escalation

r = discount rate, beyond year 2000 6%.

$$K = (1+e)/(1+r)$$

Source: Ref. 5,8

FIGURE 4-2 FUNCTIONAL RELATIONSHIPS FOR SNAPSHOT-YEAR ANALYSIS

supplying the load. OPTMIX and TCC deal with the planning of the thermal generation mix for the study year. FASCOS calculates the yearly production cost of serving the yearly load by the generation mix in the system.

First, hourly intermittent generation existing in the system are scheduled and the hourly system load is modified accordingly. Storage units are operated to schedule hourly pumping and restitution energy. After storage units are scheduled a load duration curve called a "Thermal Load Duration Curve" based on the hourly thermal load is formed. A screening curve approach [3,14] is then applied to obtain the optimum mix to serve the "thermal" load. This part of the study is performed in OPTMIX. TCC is then used to add peaking units to satisfy the reliability requirements. A financial model is used to calculate the investment costs and other fixed costs for the addition. The outputs from OEP model are the optimum generation mix, the available generation reserve of the mix, production cost, the capital cost for the snapshot year, and the expected energy output for individual units in the system. Figure 4-2 illustrates the functional relationship between different models in OEP [27].

4.7 CAPACITY AND ENERGY CREDITS

In this study, the capacity and energy credits were not pre-specified, rather calculated from savings due to integration of solar PV. The capacity credit was calculated by comparing the capital investment and fixed O&M cost requirements in the case with solar PV and the case without solar PV. Likewise, the energy credit was calculated as the fuel and variable O&M cost savings due to the contribution of solar PV.

4.8 BREAKEVEN COSTS

The breakeven costs in different cases of this analysis can be viewed as the total credit due to solar PV and the corresponding integration scheme.

For the no storage case, the breakeven cost, that is the total savings due to solar PV integration, is the maximum cost of solar PV system in order for solar PV to compete with conventional technologies.

For the case with residential storage, the breakeven costs represents the maximum cost of both solar PV and batteries used for the storage.

In the system storage case, the breakeven cost is the maximum cost allowed for solar PV in order to compete with conventional technology. Note that this cost does not include system storage itself, because system storage was not built for the purpose of solar PV storage.

4.9 EFFECT OF BUY-BACK RATIO

The buy-back ratio is defined as the ratio of the price (expressed in dollars per megawatt-hour) that the utility pays for the energy it buys from the solar PV owner and the cost (in dollars per megawatt-hour) that the utility charges the owner for energy that it sells to him.

The buy-back constitutes one of several factors which could induce the solar PV owner to install, at his cost, dedicated storage devices. For low buy-back ratios, he may find it economically advantageous to store surplus solar PV generation, rather than sell it at a low price and buy later at a high price.

This subject is discussed with greater detail in Section 7 where ranges of estimates for the buy-back ratio are also provided.

5.0 CASE STUDY RESULTS

The results of all three penetration levels for solar PV using different integration schemes, that is without storage — with residential dedicated storage — with system storage, and results of the comparisons are presented in this section. Figure 5-1 helps the reader spot where different results and comparison of results are tabulated and which tables are the result of which computer runs. The last section of this chapter presents the generation mix, capacity factor, and fuel consumptions for each case.

5.1 RESULTS FOR SOLAR PV WITHOUT STORAGE

For each of the three penetration levels, the utility capacity, energy, and revenue requirements in the case with solar PV were compared with those of the Base Case. The Base Case results are tabulated in Table 5.1. Revenue requirements were calculated as the ratio of total system cost and the system energy requirements (load).

The results of the comparison between the cases with PV and without (Base Case) for 1% penetration is given in Table 5.2. The results for 10% penetration is reported in Table 5.3 and for 20% penetration in Table 5.4. Solar PV credit (\$/MWh) was calculated as the ratio of total cost savings and the energy that was displaced by solar PV. The solar PV credit (\$/kW-yr), in parentheses, is the ratio of total savings and the rated capacity of the corresponding penetration level of solar PV.

5.2 RESULTS FOR SOLAR PV WITH DEDICATED RESIDENTIAL STORAGE

For each penetration level of solar PV, the results of the computer runs for the case with solar PV plus residential storage were compared to the results of the Base Case runs. The results of the comparison of the computer runs of the case with 1% solar PV plus residential storage and the Base Case are given in Table 5.5. The results for 10 and 20% penetration levels are given in Tables 5.6 and 5.7, respectively.

Figure 5-1. Comparison of Different Cases.

Table 5.1. Base Case System Without Solar PV And
Without Storage

1. Capacity Requirements	=	6250 MW
Fixed Charges/Year	=	663128 K\$
Fixed O&M/Year	=	<u>27960 K\$</u>
Total Fixed Charges/Year	=	691088 K\$
2. Energy Requirement (Load)	=	23405067 MWh
Fuel Costs	=	666972 K\$
Variable O&M Costs	=	49976 K\$
Total Variable Costs	=	716948 K\$
3. Total System Costs	=	1408036 K\$
Revenue Requirements	=	60.2 \$/MWh

Table 5.2. One Percent Solar PV Without Storage
(Compared to the Base Case).

<u>1. Capacity Related Credits</u>		
Net Capacity Credit	=	25 MW
Fixed Charge Savings	=	1412 K\$
Fixed O&M Savings	=	<u>55 K\$</u>
Total Fixed Cost Savings	=	1467 K\$
Solar PV Fixed Cost Savings	=	12.3 \$/MWh
<u>2. Energy Related Credits</u>		
Energy Displaced by Solar PV	=	120.4 GWh
Fuel Cost Savings	=	6151 K\$
Var. O&M Savings	=	<u>421 K\$</u>
Total Var. Cost Savings	=	6572 K\$
Solar PV Var. Cost Savings	=	53.7 \$/MWh
<u>3. Total Credits</u>		
Total Cost Savings	=	8039 K\$
Solar PV Credit	=	66 \$/MWh
		(161 \$/kW-yr)

Table 5.3. Ten Percent Solar PV Without Storage
(Compared to Base Case)

1. <u>Capacity Related Credits</u>		
Capacity Credit	=	250 MW
Fixed Charge Savings		23,452 K\$
Fixed O&M Savings		<u>968 K\$</u>
Total Fixed Cost Savings	=	24,420 K\$
Solar PV Fixed Cost Savings	=	20.0 \$/MWh
2. <u>Energy Related Credits</u>		
Energy Displaced by Solar PV	=	1222 GWh
Fuel Cost Savings	=	45,556 K\$
Var. O&M Savings	=	<u>6,347 K\$</u>
Total Var. Cost Savings	=	51,903 K\$
Solar PV Var. Cost Savings	=	42.5 \$/MWh
3. <u>Total Credits</u>		
Total Cost Savings	=	76,313 K\$
Solar PV Credit		62.5 \$/MWh
		(152 \$/kW-yr)

Table 5.4. Twenty Percent Solar PV Without Storage
(Compared to the Base Case).

1. <u>Capacity Related Credits</u>		
Capacity Credit	=	400 MW
Fixed Charge Savings	=	51,401 K\$-yr
Fixed O&M Savings	=	<u>2,240 K\$-yr</u>
Total Fixed Cost Savings	=	53,641 K\$-yr
Solar PV Fixed Cost Savings	=	22 \$/MWh
2. <u>Energy Related Credits</u>		
Energy Displaced by Solar PV	=	2,442 GWh
Fuel Cost Savings	=	78,482 K\$
Var. O&M Cost Savings	=	<u>4,239 K\$</u>
Total Operating Cost Savings	=	82,721 K\$
Solar PV Operating Cost Savings	=	33.8 \$/MWh
3. <u>Total Credit</u>		
Total Cost Savings	=	136,362 K\$
Solar PV Credit	=	55.8 \$/MWh
		(136 \$/kW-yr)

Table 5.5. One Percent Solar PV, 45MW/4h Residential Storage
(Compared to the Base Case).

1. <u>Capacity Related Credits</u>		
Capacity Credits	=	30 MW
Fixed Charge Savings	=	1,412 K\$
Fixed O&M Cost Savings	=	<u>55 K\$</u>
Total Fixed Cost Savings	=	1,467 K\$
2. <u>Energy Related Credit</u>		
Energy Provided by PV	=	120 GWh
Net Energy Supplied by Storage	=	-5 GWh
Net Energy Supplied by PV + Storage	=	115 GWh
Fuel Cost Savings	=	6,000 K\$
Var. O&M Savings	=	<u>409 K\$</u>
Total Operating Cost Savings	=	6,409 K\$
3. <u>Total Credits</u>		
Total Savings for Storage + PV	=	7,876 K\$
Credit for Solar PV + Residential Storage	=	65.0 \$/MWh (157 \$/kW-yr)
Total Cost Of Residential Storage	=	2,205 K\$
Net Total Savings for Solar PV	=	5,671 K\$
Credit for Solar PV	=	47.3 \$/MWh (113 \$/kW-yr)

Table 5.6. Ten Percent Solar PV, 455MW/3h
Residential Storage (Compared to Base).

1. <u>Capacity Related Credits</u>		
Net Capacity Credit	=	350 MW
Fixed Charge Savings	=	26,005 K\$
Fixed O&M Savings	=	<u>1,075 K\$</u>
Total Fixed Cost Savings		27,080 K\$
2. <u>Energy Related Credits</u>		
Energy Provided by PV	=	1,221 GWh
Net Energy Supplied by Storage	=	-92 GWh
Net Energy Supplied by PV + Storage	=	1,129 GWh
Fuel Cost Savings	=	41,235 K\$
Var. O&M Cost Savings	=	<u>6,074 K\$</u>
Total Operating Cost Savings	=	47,309 K\$
3. <u>Total Credits</u>		
Total Savings for PV + Storage	=	74,389
Credit for PV + Res. Storage	=	60.9 \$/MWh (148.8 \$/kW-yr)
Total Cost of Residential Storage	=	22,295 K\$
Net Total Savings for Solar PV	=	52,094 K\$
Credit for Solar PV	=	42.6 \$/MWh (104.2 \$/kW-yr)

Table 5.7. Twenty Percent Solar PV, 875MW/4h Residential Storage (Compared to the Base Case).

<u>1. Capacity Related Credits</u>		
Capacity Credit	=	500 MW
Fixed Charge Savings	=	51,462 K\$
Fixed O&M Savings	=	<u>2,182 K\$</u>
Total Fixed Cost Savings	=	53,644 K\$
<u>2. Energy Related Credits</u>		
Energy Provided By Solar PV	=	2,446 GWh
Net Energy Supplied by Residential Storage	=	- 231 GWh
Energy Supplied by Storage + PV	=	2,215 GWh
Fuel Cost Savings	=	73,300 K\$
Variable O&M Savings	=	<u>7,354 K\$</u>
Total Operating Cost Savings	=	80,654 K\$
<u>3. Total Credits</u>		
Total Dollar Savings for PV + Residential Storage	=	134,298 K\$
Total Credit for Solar PV + Residential Storage	=	54.9 \$/MWh (135 \$/kW-yr)
Total Cost of Residential Storage	=	42,875 K\$
Net Total Savings for Solar PV	=	91,423 K\$
Credit for Solar PV	=	37.38 \$/MWh (91.4 \$/kW-yr)

The credit for solar PV plus residential storage (dollars per megawatt-hour) was calculated as the ratio of total savings for storage plus PV and the energy provided by PV. The credit for storage plus PV (dollars per kilowatt-year) was calculated by dividing the total savings for storage plus PV by rated capacity of solar PV. Total cost of residential storage was calculated by multiplying the capacity of the storage and the annualized cost of storage per unit capacity. The annualized cost of storage was 49 \$/kW-yr. The cost of storage was subtracted from the total savings due to residential solar PV plus residential storage to obtain the credit for solar PV.

5.3 RESULTS FOR SOLAR PV WITH SYSTEM STORAGE

To determine the savings of solar PV in the system with storage, the savings due to storage was determined first. The results of the computer runs for the case with system storage but with no solar PV were compared to the Base Case run and the results are given in Table 5.8. The results of the computer run of the case with solar PV plus system storage were then compared to the Base Case to determine the savings due to solar PV plus system storage. Comparing the latter results to those of Table 5.8 results in savings due to solar PV in the system with storage.

The results for 1% penetration case are given in Tables 5.9 and 5.10. For 10% penetration of solar PV, the results are found in Tables 5.11 and 5.12. Results for 20% penetration are given in Tables 5.13 and 5.14.

The solar PV credits in Tables 5.10, 5.12, and 5.14 were calculated as follows:

The solar PV credit (\$/MWh) was calculated as the ratio of the total cost savings for solar PV and the energy displaced by solar PV. The solar PV credit (\$/kW-yr) was calculated by dividing the total cost savings for solar PV and the rated capacity of the respective solar PV penetration level.

Table 5.8. No Solar PV, 500 MW/8h System Storage
(Compared to the Base Case)-- New Base Case

1. <u>Capacity Related Credits</u>		
Capacity Credit	=	550 MW
Fixed Charge Savings	=	18,598 K\$
Fixed O&M Saving	=	<u>753 K\$</u>
Total Fixed Cost Savings	=	19,351 K\$
2. <u>Energy Related Credits</u>		
Net Energy Supplied by Storage	=	- 231 GWh
Energy Generated by Storage	=	602 GWh
Fuel Cost Savings	=	20,501 K\$
Var. O&M Savings	=	<u>3,210 K\$</u>
Total Operating Cost Savings	=	23,711 K\$
3. <u>Total Credits</u>		
Total Storage Credit	=	43,062 K\$

Table 5.9. One Percent Solar PV, 500MW/8h System Storage
(Compared to Base Case).

<u>1. Capacity Related Credits</u>		
Capacity Credit	=	580 MW
Fixed Charge Savings	=	26,784 K\$
Fixed O&M Savings	=	<u>1,113 K\$</u>
Total Fixed Cost Savings	=	27,897 K\$
<u>2. Energy Related Credits</u>		
Net Energy Supplied by Storage	=	- 225 GWh
Energy Generated by Storage	=	584 GWh
Fuel Cost Savings	=	20,483 K\$
Var. O&M Cost Savings	=	<u>3,206 K\$</u>
Total Operating Cost Savings	=	23,689 K\$
<u>3. Total Credits</u>		
Total Savings for Solar PV + Storage	=	51,586 K\$

Table 5.10. One Percent Solar PV, 500MW/8h System Storage Case (Compared to the Case with 500MW/8h System Storage But No Solar PV)

1. <u>Capacity Related Credits</u>		
Net Capacity Credit	=	30 MW
Fixed Charge Savings	=	8,204 K\$
Fixed O&M Saving	=	<u>364 K\$</u>
Total Fixed Cost Savings	=	8,568 K\$
2. <u>Energy Related Credits</u>		
Energy Displaced by Solar PV	≈	120 GWh
Fuel Cost Savings	=	18 K\$
Var. O&M Savings	=	4 K\$
Total Operating Cost Savings	=	22 K\$
3. <u>Total Credits for Solar PV</u>		
Total Cost Savings for Solar PV	=	8,524K\$
Solar PV Credit	=	71 \$/MWh
		(170.5 \$/kW-yr)

Table 5.11. Ten Percent Solar PV, 500MW/8h System Storage
(Compared to the Base Case).

1. <u>Capacity Related Credits</u>		
Capacity Credit	=	850 MW
Fixed Charge Savings	=	67,174 K\$
Fixed O&M Cost Savings	=	<u>2,881 K\$</u>
Total Fixed Cost Savings	=	70,055 K\$
2. <u>Energy Related Credits</u>		
Net Energy Supplied by Storage	=	- 238 GWh
Energy Generated by Storage	=	621 GWh
Energy Displaced by Solar PV	=	1219.6 GWh
Fuel Cost Savings		44,522 K\$
Var. O&M Cost Savings	=	<u>3,604 K\$</u>
Total Operating Cost Savings	=	48,126 K\$
3. <u>Total Credit for Storage + Solar PV</u>		
Total Fixed and Var. Cost Savings	=	118,181 K\$

Table 5.12. Ten Percent Solar PV, 500MW/8h System Storage
(Compared to No PV, 500MW/8h Storage).

1. <u>Capacity Related Credits</u>		
Net Capacity Credit	=	300 MW
Fixed Charge Savings	=	48,576 K\$
Fixed O&M Savings	=	<u>2,128 K\$</u>
Total Fixed Cost Savings	=	50,704 K\$
2. <u>Energy Related Credit</u>		
Energy Displaced by Solar PV	=	1,219.6 GWh
Fuel Cost Savings	=	24,021 K\$
Var. O&M Savings	=	<u>394 K\$</u>
Total Operating Cost Savings	=	24,415 K\$
3. <u>Total Solar PV Credit</u>		
Total Savings for PV	=	75,119 K\$
Credit for PV	=	61.69 \$/MWh
		(150 \$/kW-yr)

Table 5.13 Twenty Percent Solar PV, 500 MW/8h System Storage
(Compared to the Base Case)

1. <u>Capacity Related Credits</u>		
Capacity Credit	=	1,050 MW
Fixed Charge Savings	=	69,998 K\$
Fixed O&M Cost Savings	=	<u>2,992 K\$</u>
Total Fixed Cost Savings	=	72,990 K\$
2. <u>Energy Related Credits</u>		
Energy Displaced by Solar PV	=	2,442 GWh
Net Energy Supplied by Storage	=	- 205 GWh
Total Energy Generated by Storage	=	553 GWh
Fuel Cost Savings	=	96,177 K\$
Var. O&M Cost Savings	=	<u>7,563 K\$</u>
Total Operating Cost Savings	=	103,740 K\$
3. <u>Total Credit for Solar PV + System Storage</u>		
Total Fixed + Operating Cost Savings	=	176,732 K\$

Table 5.14. Twenty Percent Solar PV, 500MW/8h System Storage (Compared to Case With 500MW/8h System Storage But No Solar PV).

1. <u>Capacity Related Credits</u>		
Capacity Credit	=	500 MW
Fixed Charge Savings	=	51,400 K\$
Fixed O&M Cost Savings	=	<u>2,239 K\$</u>
Total Fixed Cost Savings	=	53,639 K\$
2. <u>Energy Related Credits</u>		
Energy Displaced by Solar PV	=	2,442 GWh
Fuel Cost Savings	=	75,676 K\$
Var. O&M Cost Savings	=	<u>4,353 K\$</u>
Total Operating Cost Savings	=	80,029 K\$
3. <u>Total Credit for Solar PV</u>		
Total Savings for Solar PV	=	133,668 K\$
Credit for Solar PV	=	54.7 \$/MWh
		(133.7 \$/kW-yr)

5.4 CONVENTIONAL GENERATION MIX AND THEIR USE FOR EACH CASE

Table 5.15 presents the optimal conventional technology mix for all computer runs needed for this study. The total capacity required from each technology (nuclear, coal, combined-cycle, and combustion turbine) along with each technology's average capacity factor and fuel usage are provided in this table. The capacity factor for each technology is obtained by dividing the total energy expected from each technology by the product of total capacity of that technology and the number of hours in the year. Also presented in the table are the system average capacity factor, total system capacity, and total energy produced by the conventional generating technologies for each case. The average system capacity factor is obtained by calculating the ratio of total energy expected from all conventional generating technologies and the product of total system capacity and the number of hours in the year.

A number of observations can be made from the results of this table. These include:

- In all three integration schemes namely no storage, system storage or residential storage case, the system capacity factor decreases as the penetration of solar PV increases.
- The nuclear technology's capacity factor does not vary substantially from one case to another. The minimum capacity factor for nuclear units was 76.79% while the maximum capacity factor was 78.58%.
- The capacity factor variation of coal, combined-cycle, and combustion turbine are more significant.

For the interested reader, we present the relationship between the electrical energy produced by each technology and the fuel burned. According to Ref. 29 and heat rates for the combined-cycle, 1 GWh electrical energy requires 1510.7 barrels (215.87 metric tons) of distillate oil. For combustion turbines, 2403.4 barrels (343 metric tons) should be burned to produce 1 GWh electrical energy. For coal technology, 371.38 metric tons of Anthracite coal is required to produce 1 GWh electrical energy. For nuclear technology, it is common to present the relationship in terms of million Btu's. Using this convention, 10,400 MBtu of thermal energy is needed to produce 1 GWh of electrical energy.

**Table 5.15. Conventional Generation Mix, Capacity Factors, And
Fuel Consumptions for Different Cases**

TECHNOLOGY AND SIZE	BASE CASE — NO PV, NO STORAGE			SYSTEM STORAGE NO SOLAR PV		
	CAPACITY (MW)	ENERGY PRODUCED (GWh)	CAPACITY FACTOR (%)	CAPACITY (MW)	ENERGY PRODUCED (GWh)	CAPACITY FACTOR (%)
Nuclear 300 MW	2,400	16,341.7	77.94	2,700	18,308.2	77.6
Coal 300 MW	1,800	6,090.9	38.73	1,500	4,702.3	35.88
Combined-Cycle 200 MW	800	837.6	11.98	600	603	11.5
Combustion Turbine 50 MW	1,250	190.5	1.74	900	58.7	0.75
Total Capacity Requirement	6,250 MW			5,700 MW		
Total Energy Produced by Conventional Technologies	23,460.7 GWh			23,672.2 GWh		
Average System Capacity Factor	42.97%			47.54%		

Table 5.15. Conventional Generation Mix, Capacity Factors, and Fuel Consumptions for Different Cases (Continued)

TECHNOLOGY AND SIZE	Solar PV with No Storage (System or Residential)								
	1% Penetration			10% Penetration			20% Penetration		
	CAPACITY (MW)	ENERGY PRODUCED (GWh)	CAPACITY FACTOR (%)	CAPACITY (MW)	ENERGY PRODUCED (GWh)	CAPACITY FACTOR (%)	CAPACITY (MW)	ENERGY PRODUCED (GWh)	CAPACITY FACTOR (%)
Nuclear 300 MW	2,400	16,340.4	77.94	2,400	16,267.8	77.57	2,100	14,263.1	77.73
Coal 300 MW	1,800	6,014.2	38.25	1,500	4,928.7	37.60	1,800	6,021.6	38.28
Combined Cycle 200 MW	800	814.0	11.65	800	851.1	12.16	600	517.5	9.87
Combustion Turbine 50 MW	1,200	173.3	1.65	1,250	186.7	1.71	1,350	210.6	2.41
Total Capacity Requirement	6,200 MW			5,950 MW			5,850 MW		
Total Energy Produced By Conventional Technologies	23,341.8 GWh			22,234.3 GWh			21,012.7 GWh		
Average System Capacity Factor	43.09%			42.76%			41.11%		

Table 5.15. Conventional Generation Mix, Capacity Factors, and Fuel Consumptions for Different Cases (Continued)

TECHNOLOGY AND SIZE	Solar PV With System Storage -- 500 MW/8h Storage								
	1% Penetration			10% Penetration			20% Penetration		
	CAPACITY (MW)	ENERGY PRODUCED (GWh)	CAPACITY FACTOR (%)	CAPACITY (MW)	ENERGY PRODUCED (GWh)	CAPACITY FACTOR (%)	CAPACITY (MW)	ENERGY PRODUCED (GWh)	CAPACITY FACTOR (%)
Nuclear 300 MW	2,668	18,113.1	76.79	2,400	16,480.2	78.58	2,400	16,274.5	77.62
Coal 300 MW	1,482	4,749.8	36.25	1,500	5,298.0	40.42	1,500	4,543.5	34.67
Combined Cycle 200 MW	554	607.3	12.55	400	530.6	15.18	400	339.8	9.72
Combustion Turbine 50 MW	950	85.2	1.03	1,100	164.4	1.71	1,000	73.5	0.84
Total Capacity Requirement	5,654 MW			5,400 MW			5,300 MW		
Total Energy Produced By Conventional Technologies	23,555.3 GWh			22,473.0 GWh			21,231.3 GWh		
Average System Capacity Factor	47.69%			47.62%			45.86%		

Table 5.15. Conventional Generation Mix, Capacity Factors, and Fuel Consumptions for Different Cases (Continued)

TECHNOLOGY AND SIZE	Solar PV With Residential Storage								
	1% Penetration			10% Penetration			20% Penetration		
	CAPACITY (MW)	ENERGY PRODUCED (GWh)	CAPACITY FACTOR (%)	CAPACITY (MW)	ENERGY PRODUCED (GWh)	CAPACITY FACTOR (%)	CAPACITY (MW)	ENERGY PRODUCED (GWh)	CAPACITY FACTOR (%)
Nuclear 300 MW	2,400	16,338.8	77.93	2,400	16,294.0	77.70	2,400	16,157.5	77.06
Coal 300 MW	1,800	6,017.0	38.25	1,500	4,977.4	37.98	1,500	4,355.2	33.24
Combined Cycle 200 MW	800	816.2	11.68	800	877.3	12.55	600	554.1	10.57
Combustion Turbine 50 MW	1,200	172.8	1.65	1,200	180.2	1.72	1,250	173.9	1.59
Total Capacity Requirement	6,200 MW			5,900 MW			5,750 MW		
Total Energy Produced By Conventional Technologies	23,344.8 GWh			22,323.9 GWh			21,240.7 GWh		
Average System Capacity Factor	43.39%			43.31%			42.28%		

6.0 OTHER UTILITY IMPACTS

In the previous sections, the economic consequences of integrating PV systems into the utility's generation system were examined and their effect on production cost and conventional generation technologies discussed. Besides energy and capacity credits, which are the primary benefits of dispersed PV systems, there may be additional (or secondary) benefits as well as possible costs. The major positive and negative secondary benefits discussed below are:

- load-following and spinning reserve requirements,
- effects on operation and control; safety, relay coordination, and voltage regulation, and
- deferral or elimination of T&D investments.

6.1 LOAD-FOLLOWING AND SPINNING-RESERVE REQUIREMENTS

Because the fluctuating nature of the power output from intermittent generation causes increased fluctuations in the output from conventional generators, an upper limit on the penetration of intermittent generation may be identified by examining load-following and spinning reserve requirements.

Load-following is defined to be the total capacity of on-line (running) generating units that are capable of following the load. Due to the load variability, there is a minimum load-following requirement for each instant in time. For instance, during load pickups in the morning, the increase in generation capability (in MW/minute) of the system should be sufficiently large to respond to the load increases during the same period (in MW/minute). Likewise, when the system load starts to drop in the evenings the system's generation unloading capability should match the load drop. Certain units are not capable of following the load. Therefore, for the snapshot year of planning, the planner should determine the load-following requirements and use this information to alter the optimum generation mix if the optimum mix does not include enough generating capacity for load-following purposes.

The addition of intermittent generation will not cause a problem unless their power output causes the utility's load-following capability to be exceeded. With sufficient penetration of intermittent generation, the utility may have to alter its generation mix. These changes increase the utility's cost and thus reduce the avoided cost due to intermittent generation.

The net utility cost is increased because the required cycling and peaking units have a higher operating cost even though they have lesser capital costs. Spinning reserve is the difference between total capacity (in megawatts) of all on-line generating units capable of following the load and the generation output of these units. However, spinning reserve is that portion of load-following capacity which is able to provide additional megawatt output within 10 to 15 minutes.

Spinning reserve is generally expressed as a percentage of system capacity. It is used to respond to sudden increases in system load or to the loss of one or more generating units. Thus, the spinning reserve requirement is an instantaneous response capability. With intermittent generation, the utility must place a larger capacity of thermal generation or storage in the spinning reserve group to maintain system security. As the penetration of intermittent generation increases in a given system, the spinning reserve requirement will tend to increase, and these changes will increase the cost of operation. Increased spinning reserve requirement increases the production cost because units with higher incremental cost must be committed to have enough spinning reserve available.

Since residential solar PV systems will be dispersed over the whole utility's territory, it is conjectured that the variations in aggregate solar PV output will not be substantial. This is because variations in outputs of different solar PV systems will cancel each other and as a result the aggregate output does not change rapidly. Therefore, it seems that for residential solar PV systems the reduction of avoided cost due to variation of aggregate solar PV output would be minimal. Data on the magnitude and rate of change of aggregate solar PV output is unavailable at present. If such data were available, the model OEP could estimate the

change in generation mix and the expected increase in thermal operating cost. This was done in Ref. 25. Figure 6-1 suggests by how much the avoided costs could increase as a function of solar PV penetration under a highly pessimistic, that is, no spatial diversity, hypothesis. In the absence of reliable data, it seems that specific conclusions on the additional load-following or spinning reserve requirements due to the integration of residential solar PV systems, are unwarranted and possibly misleading. Further study is needed to pinpoint the effects of diversified residential solar PV technologies.

6.2 EFFECTS ON OPERATION AND CONTROL

The interconnection costs include material, design, review, and installation of additional protection equipment due to intermittent sources. To date, utilities' experience with customer-owned generation has been limited to cogeneration facilities over 200 kW. These costs consist of an additional protection package and possibly a larger power circuit breaker. It is doubtful that the cogeneration interconnection cost data provide a good basis for estimating the interconnection costs of solar PV [15]. At any rate, these costs are not an important issue for this study, since they are approximately the same for the three integration schemes and thus, should be viewed as part of the capital cost of a PV system installation.

The key issues related to the operating costs of distribution systems with intermittent sources are discussed below.

6.2.1 Safety

Customer-owned PV systems connected to a utility's distribution system pose a safety problem for utility line-crews working on equipment because their operation is not controlled by the utility, and the PV system could feedback into the utility's equipment that has been deenergized for repairs or construction.

LOAD-FOLLOWING AND SPINNING RESERVE CASES

Flat Plate PV Cases (Albuquerque -- Summer Peaking Load)

Figure 6-1. Load-Following and Spinning-Reserve Cases; No Spatial Diversity.

Note: The Base Case (zero solar PV penetration) satisfies the load following and spinning reserve requirements. All costs are utility's revenue requirements.

Source: Ref. 25.

Present utility work procedures, used to ensure the safety of line-crews, require a means of disconnecting all possible sources of voltage before the work is performed. Applied to PV systems, these procedures require a disconnect switch for PV systems that use a force-commutated inverter [15]. For those PV systems using a line-commutated inverter, these same requirements are not as specific since the work procedures do not address voltage-dependent sources. In general, the utilities will likely require a disconnection of all PV systems to ensure that unlikely events such as self-excited line-commutated inverter do not occur and endanger line-crews working on distribution systems.

Distribution systems are usually operated radially with some reconfiguration capability. The number of switches that must be opened in the absence of PV systems is typically two or three before a safe work area is established. With a large number of PV systems, this number could be substantially larger due to the extra switching operations required to disconnect each generator. Maintenance costs under these conditions would increase because the utility would be required to keep additional records and maintenance crews would lose time disconnecting the PV systems. However, this is not a key issue in this study because those costs are the same for the three integration schemes.

6.2.2 Contribution to Short-Circuit

PV systems connected to the utility's feeder increase the short-circuit current because of their fault current contributions to the system's fault current. This is not likely to be a general problem because PV systems without batteries have limited fault current potential. With batteries, PV systems will produce a higher fault current but their contributions to the utility's fault current will probably be insignificant compared with the utility's fault current.

The utility's protection equipment is coordinated for load conditions. The PV system's contribution to a utility fault has not been shown to cause a coordination problem on specific feeders examined in another study [15]. However, as the number of PV systems increase on a specific feeder, the utility would have to expend engineering time to ensure that the existing protection scheme was also adequate for active sources added to the feeder. These costs reduce the benefits derived from dispersed sources, and may be a substantial cost if new equipment must be installed. Again, this is not a key issue here because those costs are the same for the three integration schemes and this should be viewed as part of the capital cost of the PV system installation.

6.2.3 Voltage Regulation

PV systems dispersed along a feeder will affect the feeder's voltage profile. Their power output tends to increase or raise the voltage due to the decreased load [15]. Both the feeder's maximum and minimum

voltage points are increased when the PV systems are producing power. Regulating voltage under these conditions is not significantly different from normal load conditions. If, however, the number of PV systems is sufficient to charge the feeder's voltage profile outside the maximum voltage range, voltage regulation equipment may have to be adjusted and/or new regulating intelligence used to coordinate equipment with the variable output from the PV system.

6.3 DEFERRAL OR ELIMINATION OF T&D INVESTMENTS

Before discussing the T&D investments that could be eliminated or deferred by residential solar PV systems, the following points are made:

- To our knowledge, there are no norms or quick procedures approved by the Public Utility Commissions (PUCs) for estimating T&D credits in specific instances.
- If these credits could be evaluated routinely, they would probably be granted to the solar PV owner.
- This credit, in fact, would increase the avoided costs of the utility and thereby increase the price that the utility would pay for purchased energy .
- Dispersed storage devices increase the T&D credit if they are controlled so as to unload the circuits. This may provide a partial justification for residential storage.

The rest of this section considers T&D systems investments that can be deferred or eliminated as a result of interconnecting solar PVs, with and without system or residential storage. These investments include installation or replacement at various voltage levels of transformers, circuit breakers, overhead lines, underground cables, voltage regulation equipment, capacitors, switchgear, etc. Although no known result has been published on all the impacts of solar PV on T&D investments specifically, various procedures have been developed in related studies of dispersed storage and generation [16, 17, 18, 19, 20, 21]. Except for Ref. 21, these methods consider technologies

with firm output, owned and operated by utilities. As such, they may only be applicable to solar PV with dispersed system storage. These and other methods to treat solar PV with and without residential storage are discussed below.

One class of methods relates aggregated T&D system investments to total energy or capacity delivered to the customers. The methods, generally, are not based on any engineering models used in planning the T&D systems. A simple model of this type computes average T&D system investment per kilowatt-hour delivered, which is then attributed to a kilowatt-hour from dispersed storage and generation with firm output. A more elaborate method correlates the physical units of major T&D equipment (e.g., miles of 12 kV underground cable) to kilowatt-hour or kilowatt (with assumed load factors) delivered. Correlation method varies from back-of-envelope type of calculation to complicated statistical regression methods. In both methods, the historical relationship between load and physical units T&D equipment is then coupled with the cost per unit to derive the T&D investment savings per kilowatt-hour or kilowatt delivered.

Simplicity is the key advantage of this class of correlation methods. One can quickly obtain a rough estimate of the average T&D investment costs. The estimate, however, has various shortcomings; it may underestimate the T&D investment credit for dispersed power sources which would be placed in the most advantageous locations with above-average investment deferment or elimination opportunities; it may overestimate the T&D credit because 1 kW of dispersed sources does not replace 1 kW of all T&D equipment simultaneously. This is because dispersed generation devices are less reliable than, for example, transformers and overhead lines. In general, correlation methods do not include realistic planning considerations that utilities have to be concerned about when they evaluate the T&D impacts of solar PV systems.

In this study, the two correlation methods are applied to estimating the T&D investment savings due to solar PV with and without storage. The shortcomings of these methods for utility planning are noted.

Another class of methods, e.g., [16, 17, 18, 19, 20], remedies these shortcomings at the expense of increased modeling complexity. These methods are characterized by the use of some engineering models in planning T&D network expansion. The utility planning process is simulated by planning the T&D system without dispersed sources and then with dispersed source (treated as load reduction). Throughout the simulations, the same planning criteria are consistently enforced with and without dispersed devices. The difference in investment costs is the T&D investment credit due to the dispersed technology.

Results of several recent studies using the engineering modeling approach are summarized in Table 6.1. Different assumptions used in these studies are also included in this table. Also, the definitions of the estimated credits are not identical. In addition, although attempts were made to optimize the dispersed generation location using engineering judgment, there is no assurance that optimum sitings were in fact obtained. The models for optimum or near-optimum expansion of the T&D systems are extremely complex and not fully proven.

The estimated deferral credits for overhead transmission and sub-transmission (excluding any credit for reduction of losses) are in the range of 60 to 150 \$/kW. The estimated deferral credits for overhead primary distribution circuits range from 6 to 34 \$/kW.

Because the engineering approach uses more complicated models, they are only applied to a portion of the T&D system, particularly the distribution system. The key shortcoming is that the results are too specific to a particular portion of the system. One, therefore, obtains local results that cannot be generalized to the overall system.

Most of the methods discussed above do not consider intermittent sources. In general, intermittent sources would qualify for much less deferral credit, depending, of course, on the extent of their spatial diversity, their output at the time of T&D peak loads, and the amount of storage capacity. Two types of procedures may be applied to estimating the T&D investment savings.

Table 6.1. Summary of Assumptions Made and Results In T&D Credits
for Dispersed Technology Reported By Lee¹⁶, Troescher¹⁷, Ma^{18,19}, and Auges²⁰

Source/ Reference	Subsystem Studied and DET's considered	Credit and Debit components evaluated	Impact on end- use reliability	Total Credit estimated \$/kW	Comments
Lee, Ref. 16	Transmission and Subtransmission; mainly storage devices	-Investment deferral -Losses	Neglected, except through Single contin- gency	82-165	Biggest credits component was found to be deferral of subtransmission invest- ment. Underground cables were not considered. Loss credit would have been higher for generation than for storage.
Troescher, Ref. 17	Transmission and Subtrans- mission; genera- tion and storage.	-Investment deferral	Considered in part of the study	50 to 150	Approximately the same credits were obtained by single-contingency expansion and by maintain- ing end-user EUE constant.
Ma, Ref. 18, 19	Distribution; mobile generation and storage	-Investment deferral -Change in end- use reliability*	Considered	8 to 60	This is the only study in which non-coincidence of loads is considered. Subtransmission credits are included.
Auges, Ref. 20	Distribution; storage	-Investment deferral -Change in end- use reliability -Losses	Considered	13.50 to 32.50	The high credit range corresponds to mobile batteries. Possible transmission and sub- transmission credits are not discussed.

*Other components (maintenance, control and communication, etc.) are evaluated by Ma but not included in this table.

One class of methods would derate the T&D credit obtained from dispersed firm sources due to solar PV intermittent nature. The derating factor would be based on the fraction of average diversified output available during the time of day that T&D peak loads are likely to occur. One method would simply multiply this derating factor to the T&D credit obtainable from firm generation. Another method would specify a "threshold" level, below which no T&D credit would be claimed and above which the derating factor would be applied. This threshold level is established to recognize the need for a certain confidence level below which T&D planners cannot count on the availability of peak loads. It is, however, very difficult to establish the "appropriate" threshold availability that would penalize intermittent source while at the same time attribute proper credits. Determining the spatial diversity of intermittent sources is also very difficult because of the lack of credible data.

Another method models the statistical characteristics of intermittent output, which are then used in conjunction with T&D system expansion models. The procedure is to first model the hourly diversified output for a certain penetration of solar PV systems, or for solar PV system with storage systems and their operating strategies. This simulation would be carried out for all the days that are likely to have T&D system peak loads. The statistical distribution of output for each hour is then calculated. Next, select a specific confidence level that T&D planners require from dispersed intermittent output. Based on this confidence level and the statistical distributions, the hourly contributions can be obtained for a period that peak loads are likely to occur. The kilowatt contribution averaged over the hours during the peak period is the equivalent amount of firm output used in T&D system expansion with intermittent sources. An example taken from Ref. 21 is illustrated in Figure 6-2 to explain this procedure.

Suppose one standard deviation, σ , is chosen to define the confidence level that T&D planners require. The curve designated by $\mu - \sigma$ in Figure 6-2 describes the hourly output above which the solar PV device would generate 84% of the time (corresponding to $\mu - \sigma$, assuming normal distributions). For example, it will generate more than 6.2 kW during the

noon hour, 84% of the time. The distribution system for this example peaks between the 15th hour (3 pm) and the 18th hour (6 pm), and the average hourly output for these hours of the μ - σ curve is only 1.9 kW. One then takes this 1.9 kW as the output for the solar PV device and uses it as firm contribution in the distribution system reexpansion with solar PV.

Note that in case the solar PV has a storage device, the output may shift some of the PV output around noon to the time of system peak load. The result would be higher output levels between 3 pm and 5 pm. This then accounts for the contribution of storage to increased firm capacity of solar PV.

The selection of the confidence level should not be arbitrary. As a guideline, the appropriate confidence level should be delivered based on the T&D system reliability without intermittent sources. The selection would be improved as utility planning staff gained experience with planning with intermittent sources.

Figure 6-2. An Example of Statistical Distribution Of Solar PV Output.

7.0 BUYBACK RATIO

The buy-back ratio is defined as the ratio of:

b = price in \$/MWh at which the utility buys energy delivered by the solar PV owner to the grid,

and

s = price in \$/MWh which the utility charges for energy it delivers to the solar PV owner.

The purpose of this section is to develop ranges for the ratio $\frac{b}{s}$. Depending on the value of $\frac{b}{s}$, as well as other factors, dedicated storage devices owned and operated by the solar PV owner may or may not be justified.

The reason why $\frac{b}{s}$ could be less than one is that the utility must charge the solar PV owner for certain costs other than the capital and operating costs of its bulk generation system, notably the capital and operating costs of its T&D system and its G&A costs.

For a given ratio $\frac{b}{s}$ and other factors, the solar PV owner may then decide if he can justify the cost of dedicated storage. Some of these other factors pertain to the financing and possible tax deduction aspects of dedicated storage and could be analyzed with the help of a solar PV owner's financial model which would be beyond the scope of this study. Other important decision factors are more subjective, such as:

- improved reliability of supply,
- increased "self sufficiency",
- reluctance to bother with the maintenance and operation of storage devices, and
- reluctance to be exposed to the performance risks of a relatively unproven technology.

Consequently, the $\frac{b}{s}$ ratio alone is not enough to predict the penetration of dedicated storage.

7.1 METHOD OF APPROACH

The method of approach taken here to estimate ranges for $\frac{b}{s}$ consists of the following two key steps, namely:

- estimate the T&D and G&A costs expressed in \$/MWh that the utility would have to add to its bulk power cost and derive tentative values of $\frac{b}{s}$.
- discuss the current regulatory environment and its possible impact on $\frac{b}{s}$.

7.2 ESTIMATION OF T&D AND G&A COSTS

Two methods were used to estimate these costs. The first is based on 1977 statistical data (Ref. 7) which show that the U.S. average residential rate is 1.26 times the average rate over all classes. Therefore, if one knows the average revenue requirements in \$/MWh, one can estimate the residential rate by applying the 1.26 factor.

By applying a 15% fixed charge rate to the total T&D plants in service and dividing by the annual sales, the T&D charges were estimated to be 6.4 \$/MWh. The T&D operating costs and the G&A costs amount to 3.9 \$/MWh. Thus the total T&D and G&A cost of 10.3 \$/MWh is added to the nominal 60.2 \$/MWh of average generation cost obtained for the year 2000 in this study. This results in a 70.5 \$/MWh revenue requirement. Finally, by applying the 1.26 factor, an average residential rate of 88.8 \$/MWh is obtained. Thus, the utility's "surcharge" for T&D and G&A costs is $88.8 - 60.2 = 28.6$ \$/MWh.

The second method is based on the 15.4 \$/MWh for total T&D costs allocated to the residential customer by Baughman and Bottaro (Ref. 22). Since it is in 1972 dollars, an inflation factor of 1.5 (equivalent to 6% inflation rate) is used to convert it into 1979 dollars. Thus, the residential T&D cost is estimated to be 23 \$/MWh. This second method excludes much of the G&A cost; it constitutes a cross check of the first estimate of 28.6 \$/MWh.

7.3 RESULTING ESTIMATES OF $\frac{b}{s}$

These estimates are used in Table 7.1 to obtain a range for the ratio $\frac{b}{s}$. The calculations in this table depend on the following key assumptions:

- The buy-back price b is equal to the total avoided cost consisting of both energy and capacity credits.
- The average generation cost is in fact the figure of 60.2 \$/MWh determined by OEP for the year 2000 Base Case (Table 7.2).

Since for the other cases studies, the avoided costs are somewhat different, but the average generation costs remain substantially the same, the buy-back ratio would vary somewhat. Table 7.3, based on the same arithmetic used in Table 7.1, indicates the resulting variation of the buy-back ratio.

Table 7.1 Estimates of Utility Buy-Back Ratio $\frac{b}{s}$
for the Year 2000, 10 Percent Penetration, No Storage

A) <u>Residential Rate</u>		
• Method 1		<u>Source</u>
Generation Cost from Base Case	60.2 \$/MWh	(1)
T&D Plants in Service in 1977	76.8 Billion \$	(2)
1977 Annual Sales ¹ *	1799×10^6 MWh	(2)
T&D Fixed Charges ¹	6.4 \$/MWh	
T&D Operating Costs and G&A [*] in 1977	7.0 Billion \$ (3.9 \$/MWh)	(2)
Total T&D and G&A [*]	10.3 \$/MWh	
Total Revenue Requirement	70.5 \$/MWh	
Residential Rate, s ²	88.8 \$/MWh	
• Method 2		
Generation Cost	60.2 \$/MWh	(1)
Residential T&D Cost in 1972	15.4 \$/MWh	(3)
Residential T&D Cost in 1979 ³	23.0 \$/MWh	
Residential Rate	83.2 \$/MWh	
B) <u>Buy-Back Price</u> ⁴		
Energy Credit	42.5 \$/MWh	(1)
Capacity Credit	20.0 \$/MWh	(1)
Total Credit (Avoided Cost)	62.5 \$/MWh	
C) <u>Buy-Back Ratio</u>		
High Estimate ⁵	$\frac{62.5}{83.2} = .75$	
Low Estimate ⁶	$\frac{62.5}{88.8} = .70$	

Sources: (1) OEP simulation of the Base Case.

(2) Statistics of Privately Owned Electric Utilities in the U.S. 1977, DOE/EIA-0044(77), U.S. Department of Energy, Jan. 1979..

(3) Baughman and Bottaro, "Electric Power Transmission and Distribution Systems: Costs and Their Allocation," IEEE Trans PAS, June 1976.

* Strictly speaking, the assumption of G&A and T&D expenses being proportional to energy only, used in this study, may not be completely accurate because the G&A and to a lesser extent, T&D expenses of very small utilities tend to be greater, on a per GWh sold basis, than those of large utilities.

Table 7.1 Estimates of Utility Buy-Back Ratio
(continued)

- Notes:
1. Assuming 15% fixed charge rate.
 2. Equals 1.26 times total revenue requirement.
 3. An inflation factor of 1.5 is applied to the T&D cost in 1972, assuming zero real escalation in the past as well as in the future.
 4. Ignores the utility costs for spinning reserve, load following capacity, distribution protection, voltage compensation, metering, etc.
 5. Using the residential rate by Method 2.
 6. Using the residential rate by Method 1.

Table 7.2 Base Case System W/O Solar PV and W/O Storage

1. Capacity Requirements	=	6250 MW
Fixed Charges/Year	=	663128 K\$
Fixed O&M/Year	=	<u>27960 K\$</u>
Total Fixed Charges/Year	=	691088 K\$
2. Energy Requirement (Load)	=	23405067 MWh
Fuel Costs	=	666972 K\$
Variable O&M Costs	=	<u>49972 K\$</u>
Total Variable Costs	=	716948 K\$
3. Total System Costs	=	1408036 K\$
Revenue Requirements (\$/MWh)	=	60.2 \$/MWh

Table 7.3 Variation of Buy-Back Ratio

Penetration Level, Percent	Type of Integration	Buy-Back Ratio Estimate	
		High	Low
1	No Storage	.79	.74
1	System Storage	.85	.80
1	Residential Storage	.78	.73
10	No Storage	.75	.70
10	System Storage	.74	.69
10	Residential Storage	.73	.68
20	No Storage	.67	.63
20	System Storage	.66	.62
20	Residential Storage	.66	.62

7.4 CURRENT REGULATORY ENVIRONMENT

Section 210 of the Public Utility Regulatory Act (PURPA) of 1978 addresses the interactions between the utilities and cogeneration and small power production. Solar PV sources fall under the heading of small power production.

The Act specifies that the utility must offer to purchase electric energy from any qualified small power production facility and that the rates for such purchase shall be just and reasonable to the electric consumers of the electric utility and be in the public interest. This rate shall not exceed the incremental cost to the utility for alternative electric energy.

The Act is expected to have a substantial impact on the relationship between the utility and the solar PV owner. Its intent, it appears, is to encourage the development of cogeneration and small power production if such development is in the interest of the rate payers, that is, if it is cost-effective from the point of view of the community. The State Public Utility Commissions are charged with the responsibility of developing specific regulatory procedures, notably rates, in accordance with the general guidelines provided by the Act.

There is little doubt that the State Public Utility Commissions do not yet know how to address many important questions that are implied by the Act, for example:

- What is the "incremental cost to the utility" which constitutes the upper bound of what the utility may be asked to pay?
- Does it include the utility's capital costs (capacity credit)?
- If so, how is the capacity credit measured?
- How is the energy credit measured? Is this done by correlating the hourly production of the solar PV owner to the utility's incremental cost or by setting time-of-day rates that constitute expected average incremental costs for that part of the day?

- What energy must the utility purchase? Is it the whole production or only the surplus?
- Will there be a credit or penalty for T&D expenses deferred or incurred by the utility? How are these credits or penalties estimated?
- Will there be a penalty for additional spinning reserve and load following capability that certain intermittent small power sources may require? How will this penalty be estimated?

The California Public Utility Commission (CPUC) has recently developed regulations which address some but not all of these questions (Refs. 23 and 24). These regulations will be summarized below and interpreted from the point of view of this study and the impact that they may have on the buy-back ratio.

It is understood that the CPUC rulings may differ from those of other states and that consequently their impacts may not apply precisely to other states. Nevertheless:

1. The utility is ordered to pay the full amount of the avoided cost; in other words, it must pay for both energy and capacity at its incremental cost. It is recalled that this is one of the key assumptions made in the study.
2. The utility must offer the small power generator the option of either:
 - buying the whole production at "avoided cost" and selling the energy required by the producer at the "filed rate" (simultaneous buy/sell option)
 - buying only the surplus at "avoided cost" ("buy-surplus only" option).

The important distinction between these two options is shown in Figure 7-1.

Option 2 (buy-surplus only)

Figure 7-1 Schematic corresponding to the "buy-sell" and "buy-surplus only" options.
 "b" meter measures energy bought by utility.
 "s" meter measures energy sold by utility.

Figure 7-1 does not show any dedicated storage for Option 1, as this investment is unlikely to be justified by sufficient fluctuations of the "b" rate throughout the day.

3. The CPUC ruling recognizes that the "b" rate may be higher than the filed rate "s" and that therefore Option 1 may be very attractive for the solar owner. The reason for this is two-fold:

- the filed rate "s" is based on an average cost which includes older and usually less expensive generation sources and fuel supply contracts.
- the "b" rate is based on the avoided cost which may be very high in those instances where the utility has a bad mix, such as excessive oil-fired capacity.

In this study, the year 2000 generation costs were used as a basis for estimating the "s" rate and the distinction between "old" and "new" costs was not made. Also, it was assumed that the "with" generation mix was optimal.

Apart from the fact that $\frac{b}{s}$ may exceed one, the CPUC does not know, at the present time, what the likely values of $\frac{b}{s}$ might be. In specific instances, the average rate at the level of bulk power supply could be estimated approximately by dividing the bulk power capital and operating costs including their prorated overhead and profit factors by the yearly energy delivered.

4. The CPUC recognizes the shortcomings of currently available methods for estimating the capacity and energy credit components of the avoided costs which determine the "b" rate. One rather common procedure is to equate the customer-owned generation source to a fictitious utility-owned source, the capacity and energy costs of which are known. Thus, the capacity contribution of cogeneration might be equated to that of a combined-cycle unit because the expected plant factors are similar. It appears difficult to extend this already doubtful procedure to intermittent sources. The potential of OEP (or similar) models as used in this study for establishing capacity credits is recognized, but there appears to be no actual regulatory applications yet.

The energy credits are measured approximately by means of three constant values of the "b" rate corresponding to the peak, intermediate and off-peak daily periods of the season.

5. The CPUC recognizes that dispersed sources may qualify for T&D credits, which would increase the "b" rate, but admits that it does not know of any practical procedures for estimating these credits in specific instances. Similarly, there does not appear to be any practical procedures for estimating the penalties (that would reduce the "b" rate) associated with the additional integration costs, for example special protective devices, that might be incurred by the utility.

7.5 POSSIBLE IMPACT OF THE AVERAGE GENERATION COST

It was assumed earlier in this study (see Table 7.1) that the average generation cost corresponded to an optimum year 2000 mix from which old generation and fuel contracts were excluded. Since there is evidence that "new" generation costs tend to exceed average costs the buy-back ratios estimated in Table 7.3 should be revised in specific instances by reducing the generation cost from 60.2 \$/MWh to the average generation cost. This will lead to higher buy-back ratios. If, in addition, the utility has a bad mix resulting in exceptionally high near-term avoided costs, the "b" rates could be higher than those estimated under the hypothesis of an optimal mix. This would further increase the buy-back ratio.

7.6 OPTIMAL SOLUTION FOR THE SOLAR PV OWNER

For the estimated ranges of the buy-back ratio, it is possible to determine for the two options discussed if dedicated storage may be justified from the user's point of view. It is restated that the buy-back ratio is an important, though not the only factor that would influence the user's decision.

"Simultaneous buy-sell" is obviously the favored option when the $\frac{b}{s} > 1$, where b is the average rate paid by the utility for the energy bought in the course of the day. It appears unlikely that the user would install storage to retune his production in order to increase this average rate.

If $\frac{b}{s} < 1$, the "surplus-only" option would be preferred by the user. Depending on the value of $\frac{b}{s}$ and the round-trip efficiency η of the storage device, this investment may be considered. Assuming first that the storage has no capital cost, and that b is constant regardless of whether there is storage or not, the ratio $R_0 = \eta$ constitutes the dividing line for which the "with" and "without" storage cases are equally advantageous for the user. Storage would be justified if $\frac{b}{s} < R_0$. The efficiency η is estimated to be in the range of 0.60 to 0.75.

If, on the other hand, the prorated fixed charges "c" of storage are considered, the ratio $R_0 = \eta - \frac{c}{s}$ constitutes the new dividing line. This relation can be derived by assuming a transaction in which 1 kWh of surplus is sold at "b" in the "without" storage case and a subsequent purchase at ηs is avoided in the "with" storage case where, however, the gross saving must be reduced by "c". The prorated storage cost "c" is estimated as follows:

Let: B = Cost of 1 kWh of storage

f = Fixed charge rate

Bf = Annual cost of storage

n = Number of times (transactions) per year during which a surplus kWh is stored

$\frac{Bf}{n} = c$ in \$/kWh - transaction

Example:

Let: $B = 80$ \$/kWh*

$f = 0.25$ to reflect the limited life-time of batteries

* Figures of this order were used by Lee and Peschon in Ref. 16.

$$B_f = 20 \text{ \$/kWh-yr}$$

$$n = 365 \text{ cycles/yr}$$

$$\frac{B_f}{n} = 54.8 \text{ mills/kWh-transaction}$$

$$\eta = .75$$

$$s = 86 \text{ mills/kWh}$$

then the ratio $\frac{b}{s}$ corresponding to the dividing line is

$$R_o = 0.75 - \frac{54.8}{86} = 0.113$$

and storage would be justified if $R_o < 0.113$.

7.7 OTHER CREDITS AND COSTS THAT MAY AFFECT THE BUY-BACK RATIO

The following other credits and costs are considered:

1. T&D investment deferrals. These credits could materialize for utility-owned dispersed storage in which case they would probably not affect $\frac{b}{s}$, and for dedicated storage. In the absence of storage, solar PV is not likely to qualify for a T&D credit because of the intermittent (non-firm) nature of the source. In the case of dedicated storage, a T&D credit might be allowed if the utility could count on the solar PV facility to unload the T&D circuits in the event of outages and defer reinforcements that would otherwise be required. The current regulatory attitudes seem to be favorably disposed to allowing such credits, but specific procedures for quantifying them appear to be lacking. As discussed in Section 6, credits of the order of 100 \\$/kW or 15 \\$/kWh at a 15% fixed charge rate would seem to be a reasonable estimate. Thus, the solar PV capacity or energy values shown in Table 1.2 and consequently the avoided cost b could increase by approximately 10%.

2. Utility costs for interconnection. The current regulatory attitude is that all interconnection-related costs should be borne by the solar PV owner and thus $\frac{b}{s}$ would not be affected.

3. Spinning reserves and load following. As discussed in Section 6, the widespread introduction of solar PV could force the utility to depart from an optimal mix by installing more units with good dynamic response and to maintain more spinning reserve capability which would result in higher operating costs than would otherwise be the case. It is our judgment that the resulting penalty (reduction of b) cannot at present be estimated adequately because there are no data on the magnitude and rate of change of the aggregate output of the solar PVs dispersed over the service territory of a utility.

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APPENDICES

APPENDIX A:

DIFFERENCE BETWEEN "COMMUNITY" AND "RESIDENTIAL" STORAGE

This appendix discusses the difference between "community" and "residential" storage. Community storage in this context is meant to be the storage unit operated based on the aggregate solar PV systems output and residential load of "all" residential customers who own solar PV systems. On the other hand "residential" storage is meant to be the storage operated by the individual residential customer who own the PV system and its operation is based on the individual customer's load and solar PV output.

The following is an example to show that the two could give different results. The utility model used for community type operation is given in Figure A-1.

Figure A-1. Community Storage

The model used for multi-resident case ("residential") is presented in Figure A-2.

In order to show that Figures A-1 and A-2 could give different results (flow of electric energy to and from the utility), consider the following situation:

FIGURE A-2. Residential Storage

Let us assume that residential system of Figure A-1 represents the aggregate of the three residential systems of Figure A-2, each having a load of 200 MW, 400 MW, and 200 MW respectively.

The rest of assumed data and required calculations and results are tabulated in Table A-1. One can see that the two cases are not identical.

In order to see how different the results of the two cases are, one day operation of a community house (Figure A-1) system (load-solar PV-storage) and a residential (Figure A-2) system were simulated. The resultant modified solar PV outputs as seen by the utility are slightly different, implying that the difference will not be significant for the purposes of this study. The modified solar PV in both cases are tabulated in Table A-2.

Table A-1. One-Hour Residential Storage Operation Using Figures A-1 and A-2 Models for the Three Household Cases.

Figure A-2 Case	Load (MW)	PV (MW)	Charging (MW)	Discharging (MW)	Modified PV	Observation
R #1	300	125	0	175	300	
R #2	100	250	150	0	100	
R #2	0	125	125	0	0	
System	400	500	275	175	400	
						Net energy charged = $275 - \frac{175}{(0.85)^2} = 33 \text{ MW}$
Figure A-1 Case	400	500	100	0	400	Net energy charged = 100 MW

Note: $(0.85)^2$ = round-trip efficiency of the storage unit.

Table A-2. One Day Hourly Modified Solar PV Energy (MWh) Using Figures A-1 and A-2.

FIGURE A-1
A-2
24 Households

HOUR 1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
121.5	100.6	81.2	84.5	93.6	80.8	180.2	205.3	153.9	111.1	134.1	133.3	126.1	127.8	119.0	129.4	167.4	219.0	245.2	265.0	309.5	265.8	181.7	161.9
120.9	100.3	80.7	84.0	93.6	80.9	179.6	204.9	153.6	110.9	134.3	132.6	125.9	127.2	118.8	128.7	166.6	218.4	245.0	264.2	308.8	263.5	180.5	162.7

Note: -- For residential storage case, twenty-four household load data was used (data from a utility in the East-Central-Area-Reliability Council territory).

-- For community storage case aggregate load was used.

APPENDIX B

This appendix is intended to shed some light on the question of why some of the results in this report are different from those of the previous report (see Ref. 26). It also discusses different dedicated residential storage operation policies. Specifically, this appendix presents the following:

1. Reoptimization of Generation Mix vs. Fixing the Base and Intermediate Generation After Introducing Solar PV and System Storage.
2. Four Seasonal Residential Load Shapes vs. One Residential Load Shape.
3. Sensitivity With Respect to System Storage Amounts.
4. Sensitivity With Respect to Residential Storage Strategies.

1. REOPTIMIZATION OF GENERATION MIX VS. FIXING THE BASE AND INTERMEDIATE GENERATION AFTER INTRODUCING SOLAR PV AND SYSTEM STORAGE

In the preliminary report on the subject of system integration issues of residential solar PV systems to determine the savings due to 10% solar PV penetration and 750 MW/6.8h system storage [26], the base and intermediate generation were fixed from the Base (no PV, no storage) Case. The results of the comparison of costs in this case with those of the Base Case are given in Table B.1.

In a different case for determining the same benefits after introducing solar PV plus system storage, the whole mix was reoptimized instead of fixing some of the generation. The results are tabulated in Table B.2.

TABLE B.1

CASE 2 Solar PV with 750 MW System Storage
 Utility Buyback Allowed (Compared to
 System without Solar PV and without
 System Storage)—System Storage is 6.8
 Hours of Rated Discharge

1. <u>CAPACITY CREDIT</u>	
16 CT (50 MW size)	= 800 MW
Fixed Charge Savings/yr	= 22,595 K\$
Fixed O&M Savings/yr	= <u>890 K\$</u>
2. <u>ENERGY CREDIT</u>	
Energy Displaced by Solar PV	= 1,221 GWh
Net Energy Supplied by Storage	= - 133 GWh
Total Energy Generated by Storage	= 480 GWh
Fuel Cost Savings	= 72,471 K\$
Variable O&M Savings	= <u>3,745 K\$</u>
Total Variable Cost Savings	= 76,216 K\$
3. <u>TOTAL CREDIT FOR SOLAR PV + SYSTEM STORAGE</u>	
	99,701 K\$

TABLE B.2

750 MW/6.8 h System Storage Plus 10% PV
Reoptimizing the Mix Comparison with
Base Case

1. <u>CAPACITY RELATED CREDITS</u>		
OPWR + 300 Coal + 200 cc + 9(50)	=	950 MW
Fixed Charge Savings/year	=	64,172 K\$
Fixed O&M Savings/year	=	<u>2,682 K\$</u>
Total Fixed Charge Savings/year	=	66,854 K\$
2. <u>ENERGY RELATED CREDIT</u>		
Energy Displaced by Solar	=	1,220 GWh
Energy to Storage (Energy supplied by storage)	=	<u>- 188 GWh</u>
Total Energy Generated by Storage	=	489 GWh
Fuel Cost Savings	=	52,191 K\$
Variable O&M Savings	=	<u>3,792 K\$</u>
Total Variable Cost Savings	=	55,983 K\$
3. <u>TOTAL CREDIT FOR SOLAR PV + SYSTEM STORAGE</u> = 122,837 K\$		

Comparison of the results for reoptimizing the mix after introducing solar PV and 750/6.8h system storage and the case where base and intermediate generation are fixed after introduction of solar PV and system storage, shows that:

- Not reoptimizing the mix;
Credit for solar PV = 37.6 \$/MWh (92 \$/kW-yr)
- Reoptimizing the mix;
Credit for solar PV = 56.77 \$/MWh (138 \$/kW-yr)

Conclusion: Reoptimizing the mix has a significant effect on the results. Therefore, for this study, we reoptimized the mix after introducing solar PV plus storage in the system.

2. FOUR SEASONAL RESIDENTIAL LOAD SHAPES VS. ONE RESIDENTIAL LOAD SHAPE (FOR RESIDENTIAL STORAGE CASE)

It was found that the results for the two cases were slightly different. In the case of one residential load shape, the solar PV credit was 58.1 \$/MWh. The four seasonal load shape gave credits of 59.4 \$/MWh. In Ref. 26, one residential load shape was used. In this report, four seasonal load shapes were used.

3. SENSITIVITY WITH RESPECT TO SYSTEM STORAGE AMOUNTS

Two different storage units, 750 MW/6.8h and 500 MW/8h, with the same round trip efficiency of 72% were used.

- For 750 MW/6.8h, the solar PV credit was 56.24 \$/MWh (137 \$/kW-yr).
- For 500 MW/8h, the solar PV credit was 61.69 \$/MWh (150 \$/kW-yr).

The difference is obvious. Also in the DET study (Ref. 5) 500 MW/8h system storage was cited as the optimum amount. In this report, 500 MW/8h storage was used for all system storage cases.

4. SENSITIVITY WITH RESPECT TO RESIDENTIAL STORAGE STRATEGIES

Policy A. In the first case, the rule for charging and discharging the residential storage was the following:

- If solar PV output was above 250 MW, the residential storage was charged. The charging rate was the difference between solar PV output and 250 MW.
- If solar PV output was below 150 MW, the storage discharged the difference between 150 MW and solar PV output.

The results of comparing this run with the Base Case are tabulated in Table B.3.

Policy B. The residential storage policy in this case was to minimize the sell-back, i.e., when residential load was below solar PV output, the battery was charged and when the residential load was above the solar output, it was discharged. Of course, charging took place only if the battery was not fully charged and discharged only if the battery was not fully discharged. The results of this run were compared with those of the Base Case to recognize the savings and the resulting comparison is reported in Table B.4.

From the results of residential management of Policies A and B of Tables B.3 and B.4, one can see that the difference in solar PV credit is not significant. Policy B was used for the rest of the study.

TABLE B.3
RESULTS FOR SCHEDULING POLICY A

1. <u>CAPACITY CREDIT</u>		
6 CT (50 MW size)	=	300 MW
Fixed Charge Savings/year	=	8,473 K\$
Fixed O&M Savings/year	=	<u>334 K\$</u>
Total Fixed Savings/year	=	8,807 K\$
2. <u>ENERGY CREDIT</u>		
Energy Provided by Solar PV	=	1,221 GWh
Net Energy Supplied by Storage	=	- 105 GWh
Net Energy Supplied by PV + Storage	=	1,116 GWh
Fuel Cost Savings	=	52,984 K\$
Variable O&M Savings	=	<u>3,851 K\$</u>
Total Variable Cost Savings	=	56,835 K\$
3. <u>TOTAL CREDIT FOR SOLAR PV + RESIDENTIAL STORAGE</u>		
Total Savings for Solar PV + Storage	=	65,642 K\$
Credit for Solar PV and Residential Storage	=	58.8 \$/MWh (131 \$/kW-yr)

TABLE B.4
RESULTS FOR SCHEDULING POLICY B

1. <u>CAPACITY CREDIT</u>		
5 CT (50 MW size)	=	250 MW
Fixed Charge Savings/year	=	7,061 K\$
Fixed O&M Savings/year	=	<u>278 K\$</u>
Total Fixed Savings/year	=	7,339 K\$
2. <u>ENERGY CREDIT</u>		
Energy Provided by Solar PV	=	1,221 GWh
Net Energy Supplied by Storage	=	- 87 GWh
Net Energy Supplied by PV + Storage	=	1,134 GWh
Fuel Cost Savings/year	=	54,604 K\$
Variable O&M Savings/year	=	<u>3,910 K\$</u>
Total Variable Cost Savings/year	=	58,514 K\$
3. <u>TOTAL CREDIT FOR SOLAR PV + RESIDENTIAL STORAGE</u>		
Total Savings for PV + Storage	=	65,853 K\$
Credit for Solar PV + Residential	=	<u>65,853</u> $\approx$ 58.1 \$/MWh
		1,134
		(131.70 \$/kW-yr)