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EVALUATION OF THE IMPACT OF SOLAR THERMAL GENERATION ON THE RELIABILITY AND ECONOMICS OF AN ELECTRICAL UTILITY SYSTEM

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This paper describes the methodology developed to assess the potential economic and reliability impacts of the integration of solar thermal generation in an electric utility system. An annual production cost model and a static optimal mix capacity expansion model are used in the evaluation. Extensions on published models are made to account for realistic utility operating characteristics. Sample results of possible trade-off analysis are presented for a particular utility system. This work is part of the overall evaluation program of CESA-1 project of the Centro de Estudios de la Energía in Almería, Spain.

1. INTRODUCTION

The paper addresses the complex issue of assessing the economic and operation merits of new time-dependent generation technologies, particularly solar thermal plants. A fair appraisal of the economic value of solar thermal power plants must be comprehensive enough to account for all the fixed and variable costs incurred by the construction and operation of these plants, and also to include both the fuel savings and the capacity credit of the solar generation. This work focuses on the precise computation of the economic benefits devired from the integration of solar thermal plants in an electric power system. It is assumed that the costs of solar generation are externally provided, since their determination is beyond the scope of this paper; see (1) for a detailed treatment of this issue.

Thermal solar plants, even those with a limited storage capacity, are considered as non-dispatchable units since their output basically depends on the weather and the time of the day, and therefore cannot be dispatched at will regarding only demand and marginal cost considerations. These characteristics cannot be adequately handled with conventional operation and planning models. The main contribution of this work is the development of a Production Cost Model and a Generation Capacity Expansion Model that can satisfactorily account for solar plants and also for the most relevant characteristics (e.g., must run constraints in thermal units, pumped hydro units, large capacity hydro units with very limited available energy) of a standard large spanish utility. Although the paper has been specifically addressed to solar generation, the methodology to be described is equally applicable to other time dependent, i.e., non dispatchable, technologies such as wind, tidal and micro-hydro power plants.

In the methodology to be presented the impact of solar generation is accounted for by suitably modifying load demand curve of the system. This modification is performed on an hourly basis, taking into consideration the size, storage and availability characteristics of the individual solar units. The resulting demand curves are transformed into load-duration curves and fed into the Production Cost and Capacitiy Expansion Models.

The Production Cost Model uses a standard probabilistic simulation algorithm, see for instance (2, 3), that has been enhanced to include the main operating features and constraints characterizing a mixed hydro-thermal large spanish utility. These characteristics have also been incorporated into the optimal static mix algorithm of the Capacity Expansion Model. This algorithm is based on the Kuhn Tucker optimality conditions and extends previous work in this field that did not include must run constraints and operation of regular hydro and pumped-hydro units (4, 5).

A comprehensive assessment of the operation and economic impacts of a new technology must consider all the time frames of concern: from real time control issues up to long term capacity expansion considerations. This paper focuses on operation and capacity planning aspects, i.e. time frames ranging from one year to the entire life of a power plant. Consequently the effect of solar plants on the detailed hour-to-hour utility operation is not entirely captured by the models used in this paper.

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An alternate to the use of separate models for yearly production costing and long term capacity expansion is the use of global generation expansion optimization programs, see (6) for instance. The former option has been adopted here since it allows more flexibility when concentrating on specific issues or trade-offs, and also because of the significantly different levels of uncertainty involved in medium-term operation planning and long term capacity expansion models. Accordingly, this paper uses a detailed model for the former and a fairly crude one for the later.

The lack of reliable cost and operational data of existing solar thermal power plants questions the validity of the conclusions of any specific impact assessment study. Undoubtedly these data will soon grow, both in quantity and quality, and this difficulty eventually will disappear. Meanwhile the evaluation methodology should be developed and tested against the available data.

The numerical results presented in this paper use solar power plant characteristics obtained from other partial projects of the CESA-1 evaluation program, and assume operation within a utility of similar characteristics to Compañía Sevillana de Electricidad, the electric utility that operates the Almería solar generation facilities.

The results of the study consist of tradeoff curves and tables showing the relative merits of different solar penetration levels, unit sizes and operating strategies regarding the impact on the generation reliability of the electric utility and the fixed, variable and total electricity costs. Detailed information can be found in (7, 8).

2. OPERATING CREDIT

The economic value of solar generation regarding the electricity production costs is termed the operating credit, and consists of two factors: savings in fuel costs and other displaced operating and maintenance costs. The operating credit can be computed as the difference between the total production costs for the non-solar utility base case and for a utility system with the desired amount of solar generation.

2.1 Solar Generation Model

Development of an explicit solar generation model for each type of solar plant to be considered is outside the scope of this paper. What is needed is a mathematical representation of each kind of solar unit yielding its electric power output for a given set of weather conditions. Operating strategies (i.e., maximum energy output, maximum substitution cost, etc) will also influence the unit power output, specially if the unit has some storage capability. When the joint impact of several solar units sited at different locations is to be evaluated, the effect of the diverse weather conditions must also be accounted for.

In this paper the hourly electric power output for each solar unit will be assumed to be given, and also the overall theoretical unit availability (regardless of weather conditions). A computer program has been developed to compute the hourly probability mass function of the global solar generation by suitably combining the available power outputs from each unit.

2.2 Load Demand Model

The utility load demand model used by the annual Production Cost Model for the non-solar base case consists of the load duration curves for each of the considered time sub-periods (twelve months, usually). These load-duration curves are obtained by aggregation of the hourly demand forecasts for each sub-period. For a given amount and characteristics of solar generation a solar generation model must provide the probability mass function of solar power output for each hour of the considered sub-period. Hour-by-hour the probability mass functions of solar output and load demand are convolved and then aggregated to build a load-duration curve where solar generation has been accounted for. This simple procedure is described in detail in (7) and has been implemented in a program named ELECTRA.

2.3 Production Cost Model

The Production Cost Model is based on the probabilistic simulation method of Booth-Baleriaux (2, 3) and uses numerical convolution. The model can handle both fossil and nuclear thermal units with multiple valve points (i.e., multi-state availability and cost representations of a unit, accounting for partial forced outages and cost variability with output), and any number of hydro and pumped-storage units. The model accounts for spinning reserve and must-run constraints besides operation costs when determining the loading order of the units.

Inputs to the model are the load duration curve for each period, the unit characteristics (power output, valve point data: availability, fuel cost and power output level, general operating and maintenance costs, must-run constraints, available energy for each hydro unit, efficiency and reservoir size for pumped-hydro units, scheduled maintenance program, etc.) and operation data such as spinning reserve requirements.

Outputs from the Production Cost Model for each sub-period and the entire year are the values of expected energy output for all units (with specification of valve points of each unit and contribution to pump-storage from each base-loaded unit), total and per-unit operating costs and overall system reliability parameters: loss of load probability (LOLP) and expected value of non-served energy.

From these results a detailed assessment of the impact of solar generation can be easily made. In particular, comparison of the results from the non-solar base case and a case with a prespecified solar generation directly yields the annual operating credit and the reliability impact of solar generation. Straightforward economic techniques can now be used to determine the operating credit for any longer time interval, based on this one year simulation or running repeated yearly simulations as needed.

3. CAPACITY CREDIT

The capacity credit of solar generation accounts for its impact on future electric utility capacity expansion. The presence of solar power units not only modifies the operation of other existing generating units, but also influences the expansion plan by displacing and delaying in time the addition of new units, and also by changing the long term optimal capacity mix. The savings resulting from all these combined effects are termed the capacity credit and, again, it will be computed from the difference in the fixed costs of capacity expansion plans with and without the presence of solar plants.

3.1 Capacity Expansion Model

As pointed out before, in this paper the capacity credit is determined from an optimal static generation mix model. This model looks at a future year well ahead in time and computes the generation mix that meets the load demand and results in minimum total (i.e., fixed plus variable) system costs. The characteristics of the actual expansion plan leading from the current situation to the optimal mix for the prespecified future year are ignored in this model. This may be justified because of the large uncertainties in the data required to feed the model. However, the amount of presently existing capacity for each technology is accounted for.

Must-run constraints (i.e., the minimum percentage of capacity connected to the grid, of any given technology, that must be continuously running) are an actual limitation to the economic operation and planning of spanish utilities and therefore have been also included into the optimal static mix model. This significantly complicates the solution algorithm, which extends the methods presently available in the technical literature (4, 5).

The same solar generation and load demand models that were used in the Production Cost Model can be applied here. The load demand for the prespecified future year must be forecast, and a single load duration curve for the entire year will be used.

Since addition of new hydro and pumped-storage plants strongly depends on site availability, these technologies will not be included in the optimal mix algorithm. It will be assumed that an independent analysis has been performed and that the amount of new capacity for the future year of study has been already decided. It is then easy to modify the load-duration curve by adding pumping and removing regular hydro and pumped-storage hydro generation.

The optimal static generation mix model can be stated as follows:

$$\underset{T_i,\ i=1,\dots,n+1}{\text{minimize}} \quad Z = \sum_{i=1}^{n} f_i T_i / a_i + \sum_{i=1}^{n+1} v_i A_{T_i} \tag{1}$$

subject to

(i) $T_i \geq 0$ (2)

(ii) $D_m - \sum_{i=1}^{n} m_i T_i \geq 0$ (3)

(iii) $\sum_{i=1}^{n} T_i - (1+r) D_M \geq 0$ (4)

(iv) A given set of existing capacities Y_i, $i=1,\dots,n$.

(v) The load-duration curve, which symbolically can be represented as a function $P = g(u)$, although the algorithm will use a piece-wise linear representation. The load-duration curve defines the values of the A_{T_i}'s for a given set of T_i's.

T_i is the availability derated installed capacity of the i-th technology, with the n+1 subscript standing for non served power.

D_M is the peak load demand (see fig. 1).

D_m is the minimum load demand (see fig. 1).

f_i is the annual fixed cost of the i-th technology, with $f_{n+1} = 0$.

v_i is the variable MWh cost of the i-th technology.

a_i is the average per unit availability of the i-th technology.

A_{T_i} is the annual energy produced by the i-th technology and can be easily identified in fig. 1.

m_i is the coefficient defining the per unit percentage of must-run power for the i-th technology, see fig. 1.

r is the specified per unit spinning reserve margin. No provision is made for cold reserve margin and therefore all the availability installed capacity is assumed to be connected to the grid.

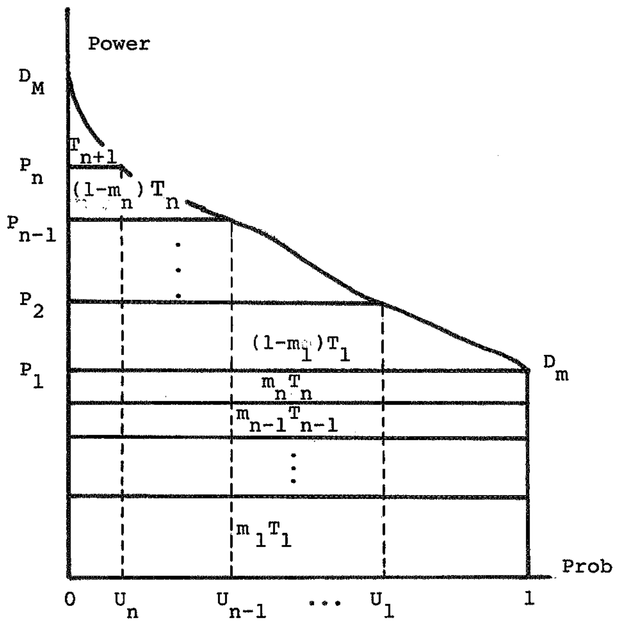

Fig. 1: Production cost model for the optimal static mix algorithm

This static optimal mix model uses a deterministic approach to production costing, see fig. 1, instead of the more sophisticated probabilistic simulation approach in the detailed Production Cost Model. In fig. 1 the installed capacity has been derated using the average availability factors a_i, which must account for all kinds of scheduled and forced, total and partial outages.

It must be noted that the reserve margin constraint (4) forces $T_{n+1} = 0$; consequently $U_{n+1} = U_n = 0$, see fig. 1. It is also important to realize that in the optimal solution the loading order of the technologies in fig. 1 must be based on increasing variable costs, once the must run capacities have been base loaded. Since economically is better not to over install capacity and there are no constraints in the model (1) - (4) to do so, the constraint (4) must become an equality, and therefore

$$P_n = (1 + r)\, D_M \qquad (5)$$

3.2 Solution algorithm

a) Without existing installed capacity.

The above stated static generation mix optimization problem is a convex nonlinear programming problem. Therefore the global optimum solution must satisfy the corresponding Kuhn-Tucker conditions:

$$\dot{Z}_{T_i} + m_i\lambda_m - \lambda_M - \lambda_i = 0, \quad i=1,\dots,n \qquad (6)$$

$$\lambda_i T_i = 0, \quad \lambda_i \geq 0, \quad i=1,\dots,n \qquad (7)$$

$$\lambda_m \left(\sum_{i=1}^{n} m_i T_i - D_m\right) = 0, \quad \lambda_m \geq 0 \qquad (8)$$

$$\lambda_M\left((1+r)D_M - \sum_{i=1}^{n} T_i\right) = 0, \quad \lambda_M \geq 0 \qquad (9)$$

where λ_i, $i=1,\dots,n$, λ_m and λ_M are the dual variables of constraints (2), (3) and (4), respectively and $\dot{Z}_{T_i}$ is the derivate of the unconstrained cost function Z with respect to T_i. For the time being the existence of already installed capacities Y_i, i=1, ..., n will be ignored.

From inspection of fig. 1 and after some manipulation it can be obtained

$$\dot{Z}_{T_i} = f_i/a_i + m_i(v_i-v_1)T + \sum_{j=1}^{n} \delta_{ij} u_j (v_j-v_{j+1})T \qquad (10)$$

where T is the considered time interval (1 year), and

$$\delta_{ij} = \begin{cases} m_i, & 1 \leq j < i \\ 1, & i \leq j \leq n \end{cases} \qquad (11)$$

Assuming that $T_i > 0$, i=1,..., n in the optimal solution (this assumption will be checked later and removed if necessary) then $\lambda_i = 0$, i=1,...,n and (6) - (11) reduce to (8) plus

$$\sum_{j=1}^{n-1} b_{ij}u_j + m_i\lambda_m - \lambda_M = k_i, \; i=1,\ldots,n-1 \quad (12)$$

$$\lambda_M = \left(\frac{f_n}{a_n} - m_n\frac{f_1}{a_1} + m_n(v_n - v_1)T + \lambda_m m_n(1-m_1)\right) / (1-m_n) \quad (13)$$

where

$$b_{ij} = \delta_{ij}\,(v_j - v_{j+1})T \quad (14)$$

$$k_i = -\frac{f_i}{a_i} - m_i\,(v_i - v_1)T \quad (15)$$

The solution algorithm for (8), (12) - (15) uses an interative scheme in λ_m. Given a numerical value for λ_m, (12) - (15) reduces to solving a linear system of n-1 equations in u_j, j=1,...,n-1. Once the u_j's are known, from the load-duration curve the P_i's (and thus the T_i's) are obtained and (8) can be checked. The iterative process starts with $\lambda_m = 0$ (i.e., inactive must-run constraint) and continues until the suitable value for λ_m is found, i.e., one that meets constraint (8).

It must be noted that the solution for u_j, j=1, ..., n-1 must be self-consistent, i.e.,

$$u_{j+1} \leq u_j \text{ and } 0 \leq u_j \leq 1, \; j=1,\ldots,n-1 \quad (16)$$

with inconsistency meaning that one or more technologies must be removed from the optimal mix. Logical rules based on the actual values of the u_j's have been implemented in the computer program, so that technologies are removed until conditions in (16) are satisfied and the opportunity costs of the removed technologies are checked to make sure they should not be used.

b) With existing installed capacity

Once the problem without existing installed capacity has been solved, two situations are posible. If

$$Y_i \leq T_i, \; i=1,\ldots,n \quad (17)$$

then the solution should obviously not be modified. However, if (17) is violated for one or more technologies, it must be input into the model the information that the fixed cost f_i for any existing capacity is zero until the already installed value Y_i is reached.

This can be easily incorporated into the model by a simple iterative procedure. Starting with the least variable cost technology violating (17) (since this has less chance of being displaced by others), the standard algorithm is rerun using a smaller value for the corresponding fixed cost f_i; this value is adjusted until either $T_i = Y_i$ or f_i must be set to zero, in which case the value of T_i obtained for $f_i = 0$ is adopted. The same procedure is orderly followed for the remaining technologies violating (17). This may cause that previously adjusted technologies will now violate (17). If this is the case, the procedure is repeated until (17) is met by all technologies.

A fair comparison of the capacity expansion plans with and without solar generation requires the LOLP for both to be the same. A simple program that uses the cumulants method (9) to compute the LOLP is run for both plans (with the T_i's divided into individual plants of representative size) and the installed capacity T_n of the last technology in the loading order is modified in the with-solar case until both LOLP coincide.

4. APPLICATION CASE

The methodology described in the previous sections has been checked against data obtained from a representative spanish electric utility and from the CESA-1 solar demonstration project. Due to the lack of actual data from operating power plants, the numerical results should be taken with caution. Here only sample results will be presented showing the range of application of the methodology. More detailed information can be found in (7) and (8). It can be concluded that the methodology can be applied to perform evaluations of the economic and reliability impacts of solar penetration.

The utility considered in the study has an annual peak demand of 2,209 MW with a minimum demand of 1,207 MW in the simulation initial year (1983). The total installed capacity is 3,544 MW, which includes 1,421 MW of fuel, 620 MW of nuclear, 300 MW of domestic coal (type I), 203 MW of domestic coal (type III), no imported coal (type II), 410 MW of conventional hydro units and 590 MW of pumped-storage hydro. In 1983 the utility also had a significant amount of energy purchase contracts.

Theoretical hourly solar generation curves for a 1 MW plant have been obtained for a complete year using a computer simulation program developed for the CESA-1 design project. Three different operation strategies are considered: standard (A), maximum energy output (B) and maximum use of storage (C) (where solar production is displaced as much as possible to hours with higher replacement cost). Solar penetration is assumed to take place according to the preliminary guidelines of the CESA-1 evaluation program, i.e., one 1 MW plant first, then one 20 MW plant and finally a series of 50 MW plants. Due to the lack of operating or simulation data for the larger plants, the production curves for the 1 MW plant have been scaled up proportionally. Estimates of fixed and operation/maintenance costs for the solar plants are also provided by the CESA-1 evaluation program.

The evaluation study has been divided into two parts: operation and planning. The first part, operation, consists of detailed monthly production cost and reliability analysis using the Production Cost Model; these analyses focus on the main trade-offs considered: increase of system LOLP with higher availability and smaller size (for a given installed capacity) of solar plants, effect of the operating strategy on the system LOLP (see fig. 2), on the operating credit per MWh produced by solar units (no significant differences were observed) and on the operating credit per installed MW of solar generation (see fig. 3), and the impact of the solar penetration level on the preceding results. These studies were performed for the initial reference year (1983) and also for future years where the non-solar capacity expansion was a priori known.

For the second part, planning, the Capacity Expansion Model was applied to a year well ahead in the future (2003) so that evaluation of the impact of solar penetration on the optimal generation mix could be meaningful. A 3.3% cumulative demand growth rate was chosen. All hydro capacity was assumed to remain at the 1983 level and no emergency purchases were allowed. Table 1 shows the data for

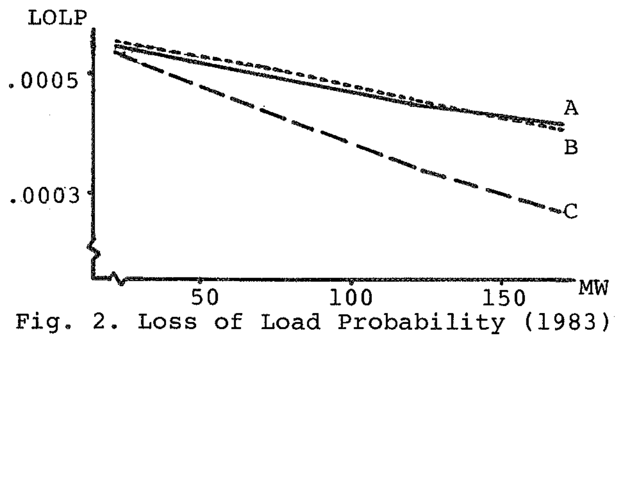

Fig. 2. Loss of Load Probability (1983)

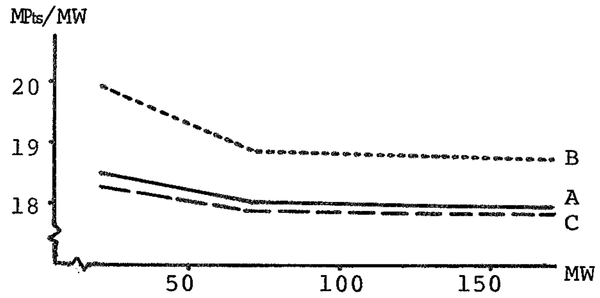

Fig. 3. Operating Credit per Installed Solar MW (1983)

the technologies considered in the model, with all costs expressed in pesetas of the year 2003 (assumed inflation rate: 7%). Different solar penetrations (such as described previously) were studied; in all cases the maximum energy output strategy was used and the spinning reserve margin was 0.03. Table 2 presents the results for one of the scenarios. It is important to notice the strong interdependence between the operating and the capacity credits: in the example shown the capacity credit is negative because solar generation has displaced the optimal generation mix towards the more expensive base-loaded units, despite the fact that less overall capacity is needed. However, base-loaded units are less expensive to operate, and the operating credit compensates for the loss in capacity credit, yielding a total value of solar generation in the vecinity of the breakeven point.

			Pts/kWh	Pts/kWyr	MW
	a_i	m_i	v_i	f_i	Y_i
Nuclear	0.700	0.950	5.70	23,500	1,107
Coal I	0.820	0.550	13.70	12,500	200
Coal II	0.800	0.500	14.80	11,700	550
Coal III	0.830	0.520	25.00	11,500	0
Fuel	0.850	0.250	27.00	9,000	100

Table 1. Basic Model Data (2003)

Operating Credit	5,701 MPts/yr
Capacity Credit	- 243 MPts/yr
. Nuclear (-86.3MW)	- 2,028 MPts/yr
. Coal I (202.6MW)	2,533 MPts/yr
. Coal II (-36.8MW)	- 430 MPts/yr
. Fuel (-35.4MW)	- 318 MPts/yr
Net Solar Value per Year	5,458 MPts/yr
Net Solar Value (per MW)	400 MPts (1985)
Solar Plant Cost (per MW)	418 MPts (1985)

Table 2. Solar Plant Credits and Cost (Simulation Year: 2003)
(Penetration: 3% or 121 MW; 30 Years Economic Life)

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