Engineering EEE

Generation Capacity Expansion Planning With Solar Power Plant Incorporating Emission

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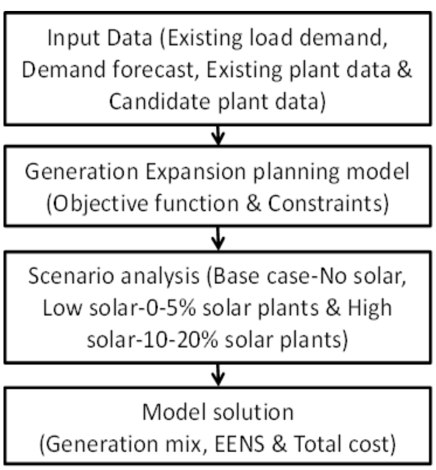
GRAPHICAL ABSTRACT



ABSTRACT

The GEP problem is a large scale, complex, non-linear optimization problem with both discrete and continuous variables. The number of candidate solutions to be evaluated increases exponentially with system size. The accurate solution of the GEP problem is essential for the planning of an economical and efficient power system. In India, the majority of the power installations are based on conventional energy sources. The exploitation of conventional energy sources has lead to increase in prices of petroleum products, environmental hazards, emission of radiations, rise in global warming etc. In order to overcome the above problems, most of the countries are focusing to develop renewable sources of energy. In this paper, an attempt is made to study the impact of replacing the high cost conventional energy oil plants by the renewable solar energy plants. The aim of this study is the application of Differential Evolution (DE) algorithm to identify the least cost expansion plan. It is applied to a test system for 6-year and 14-year planning horizons. As the solar energy composition grows steadily in the system, the impact of the same has been studied. The resulting variations of different cost components for identifying the variations in emission and reliability indices are also reported.

Keywords: *Differential Evolution (DE) – Emission - Generation Expansion Planning (GEP) - Solar Power Plants - Reliability Indices - Tamilnadu.*

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1. INTRODUCTION

India has a vast supply of renewable energy resources. The proportion of renewable energy technology (RET) in the power systems is increased from around 7.8% in 2008 to 12.3% in 2013 and it is expected to increase upto 17% of the total installed capacity by 2017. The daily average solar energy incident over India varies from 4-7 kWh/m2, depending upon the location. It amounts to an annual potential of over 5,000 trillion kWh/year. Because of the existing potential, the Government of India is going to increase the installed capacity of solar based generation plants [1].

The renewable energy sources like solar systems generate electricity without the side effects of pollutant and its emissions; The inability to store the electricity in larger quantities, forecasting of generation and control the availability of solar energy will have impacts on all the sectors of electric power system regulation, starting from economic dispatch as operational planning and generation expansion planning (GEP) as long range power system planning. This adds complexity to the capacity-expansion modeling. No single model study could incorporate all the complex issues related to the modeling of solar technologies [2].

The DE algorithm is employed to solve the GEP model solutions. The sensitivity analysis for various system generation mix to different solar power development and different emission reduction scenarios are also carried out. The resulting variations of various cost components and the reliability indices variations are also reported.

Our study details are:

1. Formulation and solution of GEP model representative of the power system of Tamil Nadu state, India for the determination of the long-term impact of the introduction of solar technologies into the system
2. Study the effect of increasing proportion of solar technology for the future generation mix for the system under consideration
3. Determination of the investment spectrum associated with varying policy propositions on the level of solar induction into the system, emissions from thermal plants and others and
4. Estimation of LOLP and EENS factors and their impact on the reliability of the system.

This paper is organized as follows: section 2 deals with literature review, section 3 gives physical system, section 4 deals with GEP problem formulation and solution methodology, Section 5 gives the results and discussions and section 6 provides concluding remarks.

2. LITERATURE REVIEW

The renewable energy is gaining attraction in both the developed and developing countries as an important area of focus for the governments in those nations [3]. In an effort to decarbonise the electric power systems, Indian policy makers have promoted the renewables with policy instruments such as Renewables Purchase obligation (RPO), Renewable Energy Certificates (REC), Tax credits, and Generation Based Incentives (GBI).

The incorporation of renewable sources into existing electrical power system creates the challenges for generation and grid operations: Dependence of location, partial unpredictability and non-controllable variability. Understanding these distinctive characteristics and their interaction with the other parts of the power system is the basis for the integration of large-capacity RE power in the grid [4].

The specific knowledge about the performance of the solar power plants may lead to the right investment decisions, a good regulatory framework and good government policies [5]. In this report, they have examined the various factors contributing to the performance of solar power plants, such as radiation, temperature and other climatic conditions, design, inverter efficiency and degradation due to aging, with the objectives of estimating performance of solar power plants at different locations, degradation of module output associated with aging as per current technology trends, review existing radiation data sources and design criteria for better performance of power plants.

Kamphol Promjiraprawat and Bundit Limmeechokchai [6] have modeled external cost and CO_2 emissions as two-objective optimization problems and the Analytic Hierarchy Process was used to determine the trade-off solution. They have demonstrated that for carbon capture and storage technology, CO_2 emissions can be mitigated by 74.7% from the least cost plan which led to the reduction of the external cost of around 500 billion US dollars over the planning horizon.

Sisternes [7] has described an Investment Model for Renewable Electricity Systems in which decisions pertaining to investment, unit commitment and energy dispatch are taken jointly. The model is formulated as a 0-1 MILP, taking capacity decisions at the individual power plant level, and accounting for techno-economic considerations such as ramp constraints, startup costs, and minimum stable outputs of thermal plants, among others.

Wajid Muneer [8] has presented an optimization model that considers various issues associated with Photo Voltaic (PV) projects like location-specific solar radiation levels, detailed investment costs representation and an approximate representation of the transmission system. A detailed case study considering the investment in large-scale solar PV projects in Ontario, Canada, is presented and discussed, demonstrating the practical application and usefulness of the proposed methodology and tools.

Regional Energy Deployment System (ReEDS) determines the geographical deployment of PV, Concentrated Solar Power (CSP), and other generation technologies based on a number of factors: regional solar resource quality, future technology and fuel price projections, future electricity demand projections, impacts of variability in renewable generation, transmission requirements and reserve requirements [9].

Schröder and Bracke [10] have showed an integrated electricity dispatch and load flow model with GEP. The target is to quantify the generation capacity requirements for 2030 and where within Central Europe it shall be ideally placed when taking into account the projected grid structure.

Grossmann et al [11] have shown that an optimization of site selection across the large geographic areas, with HVDC transmission, can address all the causes of intermittency and decrease the costs through subsequent optimization of generation capacity as well as storage. They have presented the methods to convert the daily insolation data by NASA Solar Sizer to hourly scale and use these hourly data to assess and compare large-scale networks and subsequently optimize their generation capacity and storage. Then applied these methods to twelve possible large-scale solar networks in different parts of the globe using solar data from 1986-2005.

Since mid- 1950's, many mathematical methodologies have been used in traditional GEP. They are: Dynamic Programming [12], tunnel constrained Dynamic Programming [13], Branch and Bound method [14], and Benders-Decomposition [15]. Some of the evolving techniques for GEP problem are reviewed in [16].

The Genetic Algorithm (GA) and its alternatives are applied to the GEP in [17-19]. Hybrid approaches like GA with Immune algorithm [20] and DP [21] are also applied. Eight Meta-heuristic techniques with virtual mapping procedure have been applied and the outcomes are compared with DP in [22]. The authors have observed that the Differential Evolution (DE) algorithm [22] performs better than other Meta-heuristic techniques. The DE has been extensively applied in a variety of fields including GEP [23-28]. DE operates through similar computational steps as employed by a standard evolutionary algorithm (EA). However, unlike the traditional EAs, the DE-variants perturb the preset iteration population members with the scaled differences of randomly selected and distinct population members [28]. A Multi-Objective Optimization approach is applied in [29] to the optimal allocation and sizing of Photo-Voltaic Grid-Connected Systems (PVGCS) in feeders considering both technical and economic aspects. The ease of installation, the declining cost of PV technology and the government`s Policy support for solar energy development [8] have been the catalysts for the fast growth of solar PV generation.

3. PHYSICAL SYSTEM

The economic growth and the increasing prosperity coupled with the factors such as growing rate of urbanization, rising per capita energy consumption and widening access to energy in the country are likely to push energy demand further in the country [1]. While more than 70% of India's energy is generated from coal based plants, by the end of March 2012, 12.26% of India's energy Installed capacity is from renewable sources. The number is expected to be increased to 17.12% by March 2017.

India is located in the equatorial Sun belt of the earth, thereby receiving abundant radiant energy from the Sun. India has a high level of solar radiation, and receives solar energy equivalent to more than 5,000 trillion kWh per year, which is far more than its total annual consumption [5]. The daily global radiation is around 5 kWh per sq.m per day with the sunshine ranging between 2300 and 3200 hours per year. Solar energy is still underutilized and its share in total power generation capacity stands at only 0.8%. [1].

The lifetime of the plant module is one of the four factors besides system price, system yield and capital interest rate which decides the cost of electricity produced from the module, and this lifetime is decided by the degradation rate. The effect of degradation of photovoltaic solar modules and arrays and their subsequent loss of performance have a serious impact on the total energy generation [5].

The candidate region considered for model analysis, the state of Tamilnadu, is a good candidate region for model analysis to study the impact of solar plants as a generation alternative as it has ambitious policy for solar capacity expansion. It has limited Lignite reserves for thermal plants and hence has been making attempts to increase the solar power share in the system mix. This is mainly due to the fact that the state is beginning its solar additions. In the absence of policy instruments on CO_2 purchase mechanisms, a realistic penalty cost is incorporated, in addition to the limits on high emissions plants, to get a balanced approach between the high and low emissions plants.

4. PROBLEM FORMULATION AND SOLUTION METHODOLOGY

The GEP defines WHAT, WHEN and WHERE the new generation units are to be added over the planning horizons under consideration, to fulfill the energy demand [30, 31]. The GEP problem formulation is given in detail in Appendix. The forecasted peak demand for the test system for all stages is shown in Table A1. The technical and economic data of candidate plants, solar power plants and existing plants are given in tables A2, A3 and A4 respectively [18,32].

4.1 Reliability Indices

The reliability indices; Loss of Load Probability (LOLP) and Expected Energy Not Served (EENS) can be calculated by Equivalent Energy Function Method as given in [30, 33].

4.2 Assumptions made in this model study [22, 26]

Based on the above research works by the authors the following factors are assumed in the model analysis:

- The minimum and maximum bounds for reserve margin are fixed at 20% and 60% respectively.
- The salvage factors (δ) for Oil, LNG, Coal, PWR, and PHWR are considered as 0.1, 0.1, 0.15, 0.2, and 0.2, respectively. The salvage factor for the solar plants is assumed the same as for Oil plants.
- The fuel mix ratio for Oil, LNG, Coal, PWR and PHWR are considered as 0-30%, 0-40%, 20-60%, 30-60% and 30-60% for the existing case.
- Cost of EENS is fixed at 0.05 $/kWh.
- The discount rate is fixed as 8.5%.

- It is presumed that the date of accessibility of the new generation is two years from the present date. The investment cost is presumed to occur at the start of project.
- The maintenance cost is presumed to experience in the middle of year and is computed by using the Equivalent Energy Function Method [30].
- The salvage cost is valued at the end of the planning horizon.

4.3 DE algorithm and its best parameters

In this work, the DE algorithm is used to solve GEP. The brief description of DE algorithm is given in Appendix. The best parameters obtained through trial and error procedure [22]. The best parameters for the algorithm DE is chosen through 10 independent test runs. Their values for the entire planning horizon are given in Table 1.

Table1 Best Parameters for DE

Sl. No	Parameters – DE	6 year	**14 year**
1	Number of Populations *NP*	20×n*	30×n*
2	Maximum no. of function evaluations	10000×n	35000×n
3	Mutation Strategy	DE/rand/1/bin	DE/rand/1/bin
4	Scaling Factor *F*	0.5	
5	Crossover rate *CR*	0.5	

*where n is the number of decision variable

5. RESULTS and DISCUSSIONS

Three different scenarios of solar inclusion into the system are modeled and analyzed. The BASE CASE SCENARIO, the first case, only, the existing technologies types of plants were considered as possible candidate plants for expansion and no inclusion of solar plants as technology alternative is considered. The LOW SOLAR SCENARIO, the second case, the existing oil plant replaced by the solar plants up to 5-10% of the installed capacity is considered as an alternative candidate plant. The HIGH SOLAR SCENARIO, the third case the existing oil plant replaced by the solar plants up to 10-20% of the installed capacity is considered as an alternative candidate plant. In each scenario, the impact of six different policy alternatives, based on the inclusion of Emissions Treatment Penalty Costs (ETPC) or Total Emissions Reduction Constraints (TERC) or both on the future generation mix of the system plants is studied. The analysis is carried out for 6-year and 14-year planning horizons. They are detailed as below:

POLICY ALTERNATIVES for the 6-year and 14-year planning horizons

- Policies 1A, 2A and 3A- Future Generation Mix with No ETPC and No TERC
- Policies 1B, 2B, and 3B- Future Generation Mix with ETPC and No TERC
- Policies 1C, 2C, and 3C- Future Generation Mix with No ETPC and only TERC to reduce the emissions of Policy 1A by 10%
- Policies 1D, 2D, and 3D- Future Generation Mix with ETPC and TERC to reduce the emissions of Policy 1A by 10%
- Policies 1E, 2E, and 3E- Future Generation Mix with ETPC and TERC to reduce the emissions of Policy 1A by 20%
- Policies 1F, 2F, and 3F- Future Generation Mix with ETPC and TERC to reduce the emissions of Policy 1A by 30%

5a) Model Solutions

The GEP model formulated given in the appendix is solved using the DE algorithm, which is proved to yield better results in comparison with other methods [22]. The model is solved using a system having a clock speed of 2.27 GHz and a RAM of 3 GB. The clock time taken for the solution of the 6 year model is 6.1 to 283.5 seconds and the same for 14-year model is 1725.2 to 3673.3 seconds.

For the comparison of policy impacts on the system, the Base Case Scenario (BCS) policy 1A, in which no ETPC and TERC included in the analysis, is

taken as the reference case. Moreover, the OIL, GAS and COAL plants are grouped as High Emission Plants and NUCLEAR (PWR), NUCLEAR (PHWR) and SOLAR plants are grouped as LOW EMISSION PLANTS (LEP) for convenience. However, the split up on individual plants, in these two types, is also given in the respective cases from Tables 2 and 3.
BASE CASE SCENARIO (BCS) Model Solutions:

The model solutions for all the 6 policy alternatives (from 1A to 1F) proposed above, both for 6-year and 14-year planning horizons, are given below for the BCS.

Policy 1A results

For the reference BCS policy 1A, for 6-year Planning horizon the total costs in supplying the demand of the system was 12009×106 INR; the proportion of HEP and LEP were, respectively, 73.25% and 26.75%; the LOLP and EENS were, respectively, 0.0086 days/year and 27165 MWh; and the capacity added to system was 7850 MW, making the total installed capacity 13300 MW.

For the reference BCS policy 1A, for 14-year planning horizon, the total costs in supplying the demand of the system was 21811×106 INR; the proportion of HEP and LEP were, respectively, 70.397 % and 29.603%; the LOLP and EENS were, respectively, 0.0098 days/year and 38012 MWh; and the capacity added to system was 13850 MW, making the total installed capacity 19300 MW.

Policy 1B results

For the BCS policy 1B, for 6-year Planning horizon the total costs in supplying the demand of the system was 12947×106 INR; the proportion of HEP and LEP were, respectively, 73.25% and 26.75%; the LOLP and EENS were, respectively, 0.0086 days/year and 27165 MWh; and the capacity added to system was 7850 MW, making the total installed capacity 13300 MW.

For the BCS policy 1B, for 14-year planning horizon, the total costs in supplying the demand of the system was 22627×106 INR; the proportion of HEP and LEP were, respectively, 53.571% and 46.429%; the LOLP and EENS were, respectively, 0.0088 days/year and 36376 MWh; and the capacity added to system was 14000 MW, making the total installed capacity 19450 MW.

Policy 1C results

For the BCS policy 1C, for 6-year Planning horizon the total costs in supplying the demand of the system was 12773×106 INR; the proportion of HEP and LEP were, respectively, 58.025% and 41.975%; the LOLP and EENS were, respectively, 0.0088 days/year and 30475 MWh; and the capacity added to system was 8100 MW, making the total installed capacity 13550 MW.

For the BCS policy 1C, for 14-year planning horizon, the total costs in supplying the demand of the system was 21237×106 INR; the proportion of HEP and LEP were, respectively, 37.201% and 62.799%; the LOLP and EENS were, respectively, 0.0038 days/year and 15245 MWh; and the capacity added to system was 14650 MW, making the total installed capacity 20100 MW.

Policy 1D results

For the BCS policy 1D, for 6-year Planning horizon the total costs in supplying the demand of the system was 13187×106 INR; the proportion of HEP and LEP were, respectively, 58.025% and 41.975%; the LOLP and EENS were, respectively, 0.0088 days/year and 30475 MWh; and the capacity added to system was 8100 MW, making the total installed capacity 13550 MW.

For the BCS policy 1D, for 14-year planning horizon, the total costs in supplying the demand of the system was 22035×106 INR; the proportion of HEP and LEP were, respectively, 33.333% and 66.667%; the LOLP and EENS were, respectively, 0.0026 days/year and 9825 MWh; and the capacity added to system was 14550 MW, making the total installed capacity 20050 MW.

Policy 1E results

For the BCS policy 1E, for 6-year Planning horizon the total costs in supplying the demand of the system was 13442×106 INR; the proportion of HEP and LEP were, respectively, 44.785% and 55.21%; the LOLP and EENS were, respectively, 0.0067 days/year and 22878 MWh; and the capacity added to system was 8150 MW, making the total installed capacity 13600 MW.

For the BCS policy 1E, for 14-year planning horizon, the total costs in supplying the demand of the system was 22043×106 INR; the proportion of HEP and LEP were, respectively, 36.879% and 63.127%; the LOLP and EENS were, respectively, 0.0085 days/year and 35507 MWh; and the capacity added to system was 14100 MW, making the total installed capacity 19550 MW.

Policy 1F results

For the BCS policy 1F, for 6-year Planning horizon the total costs in supplying the demand of the system was 13709×106 INR; the proportion of HEP and LEP were, respectively, 53.939% and 46.060%; the LOLP and EENS were, respectively, 0.0107 days/year and 40013 MWh; and the capacity added to system was 8250 MW, making the total installed capacity 13700 MW.

For the BCS policy 1F, for 14-year planning horizon, the total costs in supplying the demand of the system was 22163×106 INR; the proportion of HEP and LEP were, respectively, 31.724% and 68.276%; the LOLP and EENS were, respectively, 0.0046 days/year and 19100 MWh; and the capacity added to system was 14500 MW, making the total installed capacity 19950 MW.

LOW SOLAR SCENARIO (LSS) Model Solutions:

The model solutions for all the 6 policy alternatives (from 2A to 2F) proposed above, both for 6-year and 14-year planning horizons, are given below for the LSS.

Policy 2A results

For the reference LSS policy 2A, for 6-year Planning horizon the total costs in supplying the demand of the system was 12725×106 INR; the proportion of HEP and LEP were, respectively, 63.84 % and 36.16 %; the LOLP and EENS were, respectively, 0.0099 days/year and 37952 MWh; and the capacity added to system was 8850 MW, making the total installed capacity 14300 MW.

For the reference LSS policy 2A, for 14-year planning horizon, the total costs in supplying the demand of the system was 23088×106 INR; the proportion of HEP and LEP were, respectively, 60.26 % and 39.74 %; the LOLP and EENS were, respectively, 0.0090 days/year and 37824 MWh; and the capacity added to system was 15100 MW, making the total installed capacity 20550 MW.

Policy 2B results

For the LSS policy 2B, for 6-year Planning horizon the total costs in supplying the demand of the system was 12734×106 INR; the proportion of HEP and LEP were, respectively, 70.28 % and 29.72 %; the LOLP and EENS were, respectively, 0.0083 days/year and 29273 MWh; and the capacity added to system was 8750 MW, making the total installed capacity 14200 MW.

For the LSS policy 2B, for 14-year planning horizon, the total costs in supplying the demand of the system was 22271×106 INR; the proportion of HEP and LEP were, respectively, 36.08 % and 63.92 %; the LOLP and EENS were, respectively, 0.0052 days/year and 21954 MWh; and the capacity added to system was 15800 MW, making the total installed capacity 21250 MW.

Policy 2C results

For the LSS policy 2C, for 6-year Planning horizon the total costs in supplying the demand of the system was 12726×106 INR; the proportion of HEP and LEP were, respectively, 59.49 % and 40.51 %; the LOLP and EENS were, respectively, 0.0099 days/year and 33340 MWh; and the capacity added to system was 7900 MW, making the total installed capacity 13350 MW.

For the LSS policy 2C, for 14-year planning horizon, the total costs in supplying the demand of the system was 21492×106 INR; the proportion of HEP and LEP were, respectively, 39.18 % and 60.82 %; the LOLP and EENS were, respectively, 0.0026 days/year and 10075 MWh; and the capacity added to system was 14800 MW, making the total installed capacity 20250 MW.

Policy 2D results

For the LSS policy 2D, for 6-year Planning horizon the total costs in supplying the demand of the system was 13013×106 INR; the proportion of HEP and LEP were, respectively, 57.76 % and 42.41 %; the LOLP and EENS were, respectively, 0.0072 days/year and 23000 MWh; and the capacity added to system was 8050 MW, making the total installed capacity 13500 MW.

For the LSS policy 2D, for 14-year planning horizon, the total costs in supplying the demand of the system was 22191×106 INR; the proportion of HEP and LEP were, respectively, 34.86 % and 65.14 %; the LOLP and EENS were, respectively, 0.0005 days/year and 1977 MWh; and the capacity added to system was 15200 MW, making the total installed capacity 20650 MW.

Policy 2E results

For the LSS policy 2E, for 6-year Planning horizon the total costs in supplying the demand of the system was 13133×106 INR; the proportion of HEP and LEP were, respectively, 46.59 % and 53.41 %; the LOLP and EENS were, respectively, 0.0068 days/year and 21803 MWh; and the capacity added to system was 8050 MW, making the total installed capacity 13500 MW.

For the LSS policy 2E, for 14-year planning horizon, the total costs in supplying the demand of the system was 22139×106 INR; the proportion of HEP and LEP were, respectively, 37.5 % and 62.5 %; the LOLP and EENS were, respectively, 0.0012 days/year and 4718 MWh; and the capacity added to system was 15200 MW, making the total installed capacity 20650 MW.

Policy 2F results

For the LSS policy 2F, for 6-year Planning horizon the total costs in supplying the demand of the system was 13370×106 INR; the proportion of HEP and LEP were, respectively, 34.96 % and 65.04 %; the LOLP and EENS were, respectively, 0.0067 days/year and 22878 MWh; and the capacity added to system was 8150 MW, making the total installed capacity 13600 MW.

For the LSS policy 2F, for 14-year planning horizon, the total costs in supplying the demand of the system was 22953×106 INR; the proportion of HEP and LEP were, respectively, 43.88 % and 56.12 %; the LOLP and EENS were, respectively, 0.0076 days/year and 29543 MWh; and the capacity added to system was 13900 MW, making the total installed capacity 19350 MW.

The results indicate the cost we need to pay to introduce cleaner technologies and realizable systems. The costs go up by more than 100%.

HIGH SOLAR SCENARIO (HSS) Model Solutions:

The model solutions for all the 6 policy alternatives (from 3A to 3F) proposed above, both for 6-year and 14-year planning horizons, are given below for the HSS.

Policy 3A results

For the reference HSS policy 3A, for 6-year Planning horizon the total costs in supplying the demand of the system was 14854×106 INR; the proportion of HEP and LEP were, respectively, 60.64 % and 39.36 %; the LOLP and EENS were, respectively, 0.0093 days/year and 34157 MWh; and the capacity added to system was 9400 MW, making the total installed capacity 14850 MW.

For the reference HSS policy 3A, for 14-year planning horizon, the total costs in supplying the demand of the system was 25563×106 INR; the proportion of HEP and LEP were, respectively, 45.28 % and 54.72 %; the LOLP and EENS were, respectively, 0.0090 days/year and 39115 MWh; and the capacity added to system was 15900 MW, making the total installed capacity 21350 MW.

Policy 3B results

For the HSS policy 3B, for 6-year Planning horizon the total costs in supplying the demand of the system was 15283×106 INR; the proportion of HEP and LEP were, respectively, 60.64 % and 39.36 %; the LOLP and EENS were, respectively, 0.0093 days/year and 34157 MWh; and the capacity added to system was 9450 MW, making the total installed capacity 14850 MW.

For the HSS policy 3B, for 14-year planning horizon, the total costs in supplying the demand of the system was 26613×106 INR; the proportion of HEP and LEP were, respectively, 42.4 % and 57.6 %; the LOLP and EENS were, respectively, 0.0091 days/year and 39124 MWh; and the capacity added to system was 15800 MW, making the total installed capacity 21250 MW.

Policy 3C results

For the HSS policy 3C, for 6-year Planning horizon the total costs in supplying the demand of the system was 12482×106 INR; the proportion of HEP and LEP were, respectively, 47.78 % and 52.22 %; the LOLP and EENS were, respectively, 0.0086 days/year and 27165 MWh; and the capacity added to system was 7850 MW, making the total installed capacity 13300 MW.

For the HSS policy 3C, for 14-year planning horizon, the total costs in supplying the demand of the system was 21286×106 INR; the proportion of HEP and LEP were, respectively, 27.14 % and 72.86 %; the LOLP and EENS were, respectively, 0.0029 days/year and 10770 MWh; and the capacity added to system was 14550 MW, making the total installed capacity 20000 MW.

Policy 3D results

For the HSS policy 3D, for 6-year Planning horizon the total costs in supplying the demand of the system was 12730×106 INR; the proportion of HEP and LEP were, respectively, 47.78 % and 52.22 %; the LOLP and EENS were, respectively, 0.0086 days/year and 24793 MWh; and the capacity added to system was 7850 MW, making the total installed capacity 13300 MW.

For the HSS policy 3D, for 14-year planning horizon, the total costs in supplying the demand of the system was 21803×106 INR; the proportion of HEP and LEP were, respectively, 23.87 % and 76.13 %; the LOLP and EENS were, respectively, 0.0047 days/year and 19604 MWh; and the capacity added to system was 14450 MW, making the total installed capacity 19900 MW.

Policy 3E results

For the HSS policy 2E, for 6-year Planning horizon the total costs in supplying the demand of the system was 12841×106 INR; the proportion of HEP and LEP were, respectively, 24.84 % and 75.16 %; the LOLP and EENS were, respectively, 0.0090 days/year and 31573 MWh; and the capacity added to system was 7850 MW, making the total installed capacity 13300 MW.

For the HSS policy 3E, for 14-year planning horizon, the total costs in supplying the demand of the system was 21890×106 INR; the proportion of HEP and LEP were, respectively, 24.04 % and 75.96 %; the LOLP and EENS were, respectively, 0.0019 days/year and 7151 MWh; and the capacity added to system was 14350 MW, making the total installed capacity 19800 MW.

Policy 3F results

For the HSS policy 3F, for 6-year Planning horizon the total costs in supplying the demand of the system was 12901×106 INR; the proportion of HEP and LEP were, respectively, 35.84 % and 64.16 %; the LOLP and EENS were, respectively, 0.0085 days/year and 28855 MWh; and the capacity added to system was 7950 MW, making the total installed capacity 13400 MW.

For the HSS policy 3F, for 14-year planning horizon, the total costs in supplying the demand of the system was 22001×106 INR; the proportion of HEP and LEP were, respectively, 30.32 % and 69.68 %; the LOLP and EENS were, respectively, 0.0033 days/year and 12237 MWh; and the capacity added to system was 14350 MW, making the total installed capacity 19800 MW.

The highlights of model solutions are

1. By the introduction of ETPC or TERC or both, a balanced approach between the high emissions plants and the low emissions plants is achieved.
2. The impact of the introduction of the solar plants by replacing oil plants on the plant mix and system reliability for the different policy alternatives is studied.
3. The generation mix and the reliability of the system are highly sensitive to the policy alternatives for inclusion of emissions in the system. The impact on the system generation mix results in lesser total costs and better system reliability for all policy initiatives proposed.
4. The system installed capacity and the total costs have increased with the introduction of solar plants into the system and it increases the system reliability.
5. In the BCS when ETPC imposed, there is change only in the total costs and not in the generation mix. When we have introduced only TERC, there are changes in generation mix, capacity additions and total costs of the system, in addition to the changes in LOLP and EENS. When we introduce both ETPC and TERC simultaneously the total systems costs have increased for the TERC levels of 20% and 30%. The LOLP and EENS have lower values for TERC level 20% in comparison with the case where we have considered the TERC value of 10%. There is a sharp increase in EENS when we have increased the TERC value from 20% to 30%. Among the composition of system technologies alternatives when TERC was introduced higher additions in nuclear plants contributed to the reductions in total costs. In addition, for TERC values beyond 20% did not improve system variables due to capacity limitations on LEP.
6. In all BCS, LSS and HSS policy alternatives, the introduction of both ETPC and TERC have resulted the increase in the total system costs in comparison with the case where they have not been considered. Between the introduction of the ETPC or TERC, the total costs are lower for the cases where only TERC is considered than for the case when we have introduced only ETPC.
7. When Solar is chosen as a capacity alternative, in LSS and HSS, for both the cases where no ETPC and TERC is considered or the case where only ETPC was considered, the total capacity added to the system is increased more than the capacity of solar plants introduced into the system. This is mainly due to the discrete nature of the capacity of plants. As the plants can be brought into the system only in discrete numbers, for 1000 MW capacity of solar power plants introduced into the system the increase in the incremental total capacity added to the system ranges from 100 MW to 200 MW for the LSS and the same is 200 for the HSS.
8. When both ETPC and different levels of TERC are introduced, for all policy alternatives, in both LSS and HSS, for both the 6-year and 14-year planning periods, there is consistent increase in the incremental additions to the system more than the solar plants capacity brought into the system. That is, when we have put more constraints to reduce the emission

levels, the incremental additions are more than the solar capacity added meaning more base load backup and more costs.

9. For all policy alternatives, across BCS, LSS and HSS, the reduction in the HEP is high when we introduce TERC than in the cases where we have considered only ETPC. The LEP plants can not compensate their high capital costs.
10. For all policy alternatives across BCS, LSS and HSS when the TERC with higher levels of emissions reduction and in cases where incremental capacity additions are higher than the reference case, the amount of EENS in general comes down drastically, of course, at a cost.

5b) Scenario Based Analysis:

For the BCS, for 6 year planning horizon (Table 2 and 3), the proportion of HEP varies from 44.79% to 73.25% and the LEP plants varies from 26.75% to 55.21%. For the LSS, the proportion of HEP varies from 34.96% to 70.28% and the LEP plants vary from 29.72% to 65.04%. For the HSS, the proportion of HEP varies from 24.84% to 60.64% and the LEP plant varies from 39.36% to 75.16%. For the 6-year planning period, the range of variations in HEP and LEP is the lowest for BCS and the highest for HSS, whereas for 14-year planning horizon reverse is the case.

The capacity added to the system has variations across policy measures. For the 6-year planning horizon, the variations between the maximum and minimum installed capacities across policy measures are 400 MW, 800MW and 1550 MW for the BCS, LSS and HSS respectively. For the 14-year planning horizon, the variations between the maximum and minimum installed capacities across policy measures are 800 MW, 700 MW and 1550 MW for the BCS, LSS and HSS respectively.

For the 6-year planning horizon, the total system costs for different policy measures varies from 12009×106 INR to 13709×106 INR, giving a range of 1700 for BCS; 12725×106 INR to 13370×106 INR, giving a range of 645 for LSS; and 12730×106 INR to 15283×106 INR, giving a range of 2553 for HSS. For the 14-year planning horizon, the total system cost for different policy measures varies from 21811×106 INR to 22627×106 INR, giving a range of 816×106 INR for BCS; 21492×106 INR to 23088×106 INR, giving a range of 1596 for LSS; and 21286×106 INR to 26613×106 INR, giving a range of 5327 for HSS. The variations in the total cost are more for the LSS for 6-year period and HSS for the 14-year period. For the 6-year and 14-year periods the total costs variations are low in the case of BCS. This illustrates that the system is more sensitive to the policy measures when solar is brought into the system.

For the 6-year planning horizon, the EENS for different policy measures varies from 27165 MWh to 40013 MWh, giving a range of 12848 MWh for BCS; 21803 MWh to 37952 MWh, giving a range of 16149 MWh for LSS; and 24793 MWh to 34157 MWh, giving a range of 9364 MWh for HSS. For the 14-year planning horizon, the total EENS for different policy measures varies from 9825 MWh to 38012 MWh, giving a range of 28187 MWh for BCS; 4718 MWh to 37824 MWh, giving a range of 33106 MWh for LSS; and 7151 MWh to 39155 MWh, giving a range of 32004 MWh for HSS. The variations in LOLP and EENS are also more sensitive to the policy variations when solar was included as an alternative. The variation range in EENS is high for the BCS for the 6-year period and for 14-year reverse is the case.

5C) **Generation Mix and Total system costs**

For the BCS, for the 6-year planning horizon, the capacity of the HEP is 73.25% and the capacity of the LEP is 26.75%, for policies 1A and 1B. For the Policies 1C, and 1D, the installed capacity additions of the HEP is reduced to 58.02% and the same for LEP is 41.98%., as 10% emission reduction constraint is introduced in these cases. The proportions of HEP and LEP for policy 1E are respectively 44.79% and 55.21%. The highest proportion of LEP is 55.21% when the TERC is at 20% level with ETPC included.

However, for LSS, for the 6-year planning horizon, the maximum HEP proportion is for policy 2A and 2B at 63.84 % and 70.28 %, the maximum proportion of LEP plants is for the policy 2F at 65.04 %. Similarly, for LSS, for the 6-year planning horizon, the maximum HEP proportion is for policy 3A and 3B at 60.64 % and the maximum proportion of LEP is for the policy 3F at 64.16 %.

For the BCS, for the planning horizon of 6-year, the total capacity addition to the system for all six policies varied from 7850 MW to 8250 MW. For policy 1A and 1B the total capacity addition is 7850 MW. In both of these cases the generation mixes remain same. However, there is an increase in the total cost of the system as we have introduced the ETPC for the plants. With the introduction of ETPC the total system cost has increased from 12009 ×106 INR to 12947×106 INR. When TERC to reduce the total emissions by 10% from the emissions resulted in Policy 1A was introduced as part of Policy 1C, the total additional capacity has increased from 7850 to 8100 MW. The generation mix for Policy 1D, where both ETPC and TERC are introduced remain same as that for Policy 1C. In this case, there is an increase in the total cost of the system from 12773×106 INR to 13187×106 INR between these policies. For policies 1E and 1F, in additions to ETPC, TERC is introduced with the targets of 20% and 30% emissions reduction resulted in Policy 1A. For these two cases, the total additional capacity created in the system is respectively, 8150 MW and 8250 MW. The total costs of additions are respectively 13442×106 INR and 13709×106 INR.

5D) **Reliability of the system:**

Between the studies carried for 6-year planning horizons and 14-year planning horizons, for all the policy alternatives across BCS, LSS and HSS, LOLP and EENS are comparatively low for the 14-year Planning period than the LOLP and EENS values of similar policy alternatives of 6-year planning period.

For the BCS, for the 6-year and 14-year planning horizons, the EENS has the lowest values for the policies (1E and 2E) where ETPC and TERC at 20% is aimed at.

The reliability factors LOLP and EENS of the system are highly sensitive to the system generation mix for all the three scenarios under consideration. For the case when no ETPC or TERC is considered, the highest value of EENS for LSS was higher than for the BCS and HSS. When only the ETPC is considered in the model analysis, the EENS is the highest for HSS in comparison to the other two scenarios.

6. CONCLUDING REMARKS

The system identification, model formulation and model solutions for the GEP problem with future solar additions are standardized using a test case, and the impact of different critical factors, incorporated as policy alternatives on the system planning is carried out in this study. In particular, the introduction of solar plants at different levels into the system as a capacity alternative is carried out and to make the system more realistic ETPC and TERC are also included in the system analysis. A comparative analysis of the cases without and with solar power plants is also carried out. The spectrum of policy issues considered gives a better picture on the impact of solar technologies introduction into the system on the generation mix, subject to emission treatment penalty costs or emissions restriction constraints or both. This enables the planners to study the impact of other policy measures through suitable representation of variables under consideration. They will also be able to get the impact of including any particular technology type plant, and get specific answers on backup additional base load capacities required when RET plants are incorporated into the system. As an inclusion of additional trivial policy alternatives, in the absence of real system information, would be of theoretical interest only, no such attempt is made at this stage. However, the model analysis can be implemented for any, such policy proposition that might crop up in different scenarios. The scope of the study can be enlarged and made a more generalized GEP when more system information on solar energy capacities are incorporated and generation mix issues are integrated with load dispatching and other operational issues.

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APPENDIX

1. GEP PROBLEM FORMULATION

The GEP problem is corresponding to find a set of optimum decision vectors over a planning horizon that reduces the investment and operating cost under relevant constraints.

1. 1 Cost objective

The cost objective is

$$\text{Min } C = \sum_{t=1}^{T} \left[I(U_t) + M(X_t) + O(X_t) - S(U_t) \right] \quad \text{(A.1)}$$

where,

$$X_t = X_{t-1} + U_t \qquad (t = 1, 2, \ldots T) \qquad \text{(A.2)}$$

$$I(U_t) = (1+d)^{-2t} \sum_{i=1}^{N} \left(CI_i \times U_{t,i} \right) \qquad \text{(A.3)}$$

$$S(U_t) = (1+d)^{-T'} \sum_{i=1}^{N} \left(CI_i \times \delta_i \times U_{t,i} \right) \qquad \text{(A.4)}$$

$$M(X_t) = \sum_{s'=0}^{1} \left[(1+d)^{1.5+t'+s'} \left((X_t \times \text{FC}) + \text{MC} \right) \right] \quad \text{(A.5)}$$

$$O(X_t) = \text{EENS} \times \text{OC} \times \sum_{s'=0}^{1} \left[(1+d)^{1.5+t'+s'} \right] \qquad \text{(A.6)}$$

The outage cost computation of (A.6), applied in (A.1), depends on Expected Energy Not Served (EENS). The equivalent energy function method [1] is applied to compute EENS and to compute Loss of Load Probability (LOLP). This is used as a constraint.

$t' = 2(t-1)$ and $T' = 2 \times T - t$ (A.7)

C	overall cost, \$;
U_t	N-dimensional vector of newly introduced units in stage t (1 stage = 2 years);
$U_{t,i}$	the number of introduced units of type i in stage t;
X_t	cumulative capacity vector of existing units at stage t, (MW);
$I(U_t)$	the investment cost of the introduced unit in stage t, \$;
$M(X_t)$	overall operation and maintenance cost of existing and newly introduced units,\$;
s'	variable used to specify that maintenance cost is computed at the middle of each year;
$O(X_t)$	outage cost of the existing and the introduced units, \$;
$S(U_t)$	salvage value of the introduced unit at interval t, \$;
D	discount rate;
CI_i	capital investment cost of unit i, \$;
δ_i	salvage factor of unit i for calculating salvage value;
N	total quantity of dissimilar types of units;
FC	fixed operation and maintenance cost of the units, \$/MW;
MC	variable operation and maintenance cost of the units, \$;
$EENS$	expected energy not served, MWhrs;
OC	outage cost constant, \$/ MWhrs;

1.2 Constraints

The minimum cost objective function should satisfy the following constraints

i) Upper construction limit

Let Ut characterize the units to be committed in the expansion plan at stage t that should fulfill

$$0 \le U_t \le U_{\max,t} \quad (A.8)$$

where

Umax,t maximum construction limit of the units at stage t.

ii) Reserve margin

The selected units should satisfy the minimum and maximum reserve margin.

$$(1+R_{\min})\times D_t \le \sum_{i=1}^{N} X_{t,i} \le (1+R_{\max})\times D_t \quad (A.9)$$

where

Rmin minimum reserve margin;

Rmax maximum reserve margin;

Dt demand at stage t in megawatts (MW);

Xt,i cumulative capacity of unit i at stage t.

iii) Fuel mix proportion

The GEP has generated units with different fuel types as coal, Liquefied Natural Gas (LNG), oil, nuclear and solar. The selected units along with the existing units of each type should satisfy the fuel mix proportion.

$$FM_{\min}^{j} \le X_{t,j} \Big/ \sum_{i=1}^{N} X_{t,i} \le FM_{\max}^{j} \quad j = 1, 2, \ldots, \mathrm{N} \quad (A.10)$$

where,

$FM_{\min}^{j}$ minimum fuel mix proportion of type j;

$FM_{\max}^{j}$ maximum fuel mix proportion of type j;

J type of the unit (e.g., oil, LNG, coal, nuclear, solar).

iv) Reliability standard

The introduced units along with the existing units should satisfy a reliability criterion LOLP.

$$LOLP(X_t) \le \varepsilon \quad (A.11)$$

where ε is the reliability criterion for permissible LOLP. The Lowest reserve margin constraint avoids the need for a separate demand constraint.

2. Implementation of DEA to least cost GEP problem - Overall Procedure

The major steps of the DEA for solving the GEP problem is summarized as follows:

Step 1: Read all the required test system data from database for the GEP calculation

- ✓ The data of load demand and cost values at each planning stage

Step 2: Set up all the required parameters of the DEA optimization process by the user

- ✓ Set up the control parameters of the DEA optimization process that are population size (NP), Mutaion Factor (F), Crossover Probability (CR), Convergence Criterion (ε), Number of Problem Variables (D), lower and upper bounds of initial population (xjmin and xjmax) and maximum number of iterations or generations (Gmax)
- ✓ Select a DEA mutation operator strategy

Step 3: Set iteration G = 0 for initialization step of DEA optimization process

Step 4: Initialize population P of individuals

Step 5: Calculate and evaluate fitness values of initial individuals according to the problem fitness function and check constraints for each initial individual

Step 6: Rank the initial individuals according to their fitness

Step 7: Set iteration G = 1 for optimization step of DEA optimization process

Step 8: Apply mutation, crossover and selection operators to generate new individuals

- ✓ Apply mutation operator to generate mutant vectors (Vi(G)) with a selected DEA mutation operator strategy in step 2
- ✓ Apply crossover operator to generate trial vectors (Ui(G))
- ✓ Apply selection operator by comparing the fitness of the trial vector (Ui(G)) and the corresponding target vector (Xi(G)) and then select one that provides the best solution

Step 9: Calculate and evaluate the fitness values of new individuals according to the problem fitness function and check constraints for each new individual

Step 10: Rank new individuals according to their fitness

Step 11: Update the best fitness value of the current iteration and the best fitness value of the previous iteration

Step 12: Check the termination criterion

If $\left|X_i^{best} - X_i\right| > \varepsilon$ the number of current generation does not exceed the maximum number of generations G<Gmax, set G = G + 1, return to step 8 for repeating to search the solution. Otherwise, stop to calculate objective function and go to step 13;

Step 13: The output shows the least cost value of the GEP problem, and the candidate plants to be added in each stage.

Table 2 Model Solutions for BCS, LSS, HSS for all policy alternatives of the 6-year planning horizon

Policy Alternative	Scenario	Oil	LNG (CC)	Coal (Bitum)	Nuc (PWR)	Nuc (PHWR)	Solar	Added Capacity	Overall Cost×1010	LOLP (Days/ Year)	EENS× 104 (MWh)
Policy 1A	BCS	2000	2250	1500	0	2100	0	7850	1.2009	0.0086	2.7165
Policy 2A	LSS	0	3150	2500	3000	0	200	8850	1.2725	0.0099	3.7952
Policy 3A	HSS	0	2700	3000	2000	700	1000	9400	1.4854	0.0093	3.4157
Policy 1B	BCS	2000	2250	1500	0	2100	0	7850	1.2947	0.0086	2.7165
Policy 2B	LSS	0	3150	3000	1000	1400	200	8750	1.2734	0.0083	2.9273
Policy 3B	HSS	0	2700	3000	2000	700	1000	9400	1.5283	0.0093	3.4157
Policy 1C	BCS	1400	1800	1500	2000	1400	0	8100	1.2773	0.0088	3.0475
Policy 2C	LSS	0	2700	2000	0	2800	400	7900	1.2726	0.0099	3.3340
Policy 3C	HSS	0	2250	1500	0	2100	2000	7850	1.2482	0.0086	2.7165
Policy 1D	BCS	1400	1800	1500	2000	1400	0	8100	1.3187	0.0088	3.0475
Policy 2D	LSS	0	3150	1500	0	2800	600	8050	1.3013	0.0072	2.3000
Policy 3D	HSS	0	2250	1500	0	2100	2000	7850	1.2730	0.0086	2.4793
Policy IE	BCS	800	1350	1500	1000	3500	0	8150	1.3442	0.0067	2.2878
Policy 2E	LSS	0	2250	1500	0	3500	800	8050	1.3133	0.0068	2.1803
Policy 3E	HSS	0	450	1500	0	4900	1000	7850	1.2841	0.0090	3.1573
Policy 1F	BCS	1000	450	3000	1000	2000	0	8250	1.3709	0.0107	4.0013
Policy 2F	LSS	0	1350	1500	1000	3500	800	8150	1.3370	0.0067	2.2878
Policy 3F	HSS	0	1350	1500	1000	2100	2000	7950	1.2901	0.0085	2.8855

Table 3 Model Solutions for BCS, LSS, HSS for all policy alternatives of the 14-year planning horizon

Policy Alternative	Scenario	Oil	LNG (CC)	Coal (Bitum)	Nuc (PWR)	Nuc (PHWR)	Solar	Added Capacity	Overall Cost×1010	LOLP (Days/ Year)	EENS×104 (MWh)
Policy 1A	BCS	2000	2250	5500	2000	2100	0	13850	2.1811	0.0098	3.8012
Policy 2A	LSS	0	3600	5500	4000	1400	600	15100	2.3088	0.0090	3.7824
Policy 3A	HSS	0	2700	4500	5000	2100	1600	15900	2.5563	0.0090	3.9155
Policy 1B	BCS	1200	1800	4500	3000	3500	0	14000	2.2627	0.0088	3.6376
Policy 2B	LSS	0	2700	3000	4000	4900	1200	15800	2.2271	0.0052	2.1954
Policy 3B	HSS	0	2700	4000	4000	3500	1600	15800	2.6613	0.0091	3.9124
Policy 1C	BCS	1000	450	4000	5000	4200	0	14650	2.1237	0.0038	1.5245
Policy 2C	LSS	0	1800	4000	4000	4200	800	14800	2.1492	0.0026	1.0075
Policy 3C	HSS	0	450	3500	3000	5600	2000	14550	2.1286	0.0029	1.0770
Policy 1D	BCS	1000	1350	2500	2000	7700	0	14550	2.2035	0.0026	0.9825
Policy 2D	LSS	0	1800	3500	1000	7700	1200	15200	2.2191	0.0005	0.1977
Policy 3D	HSS	0	450	3000	5000	4200	1800	14450	2.1803	0.0047	1.9604
Policy IE	BCS	800	900	3500	4000	4900	0	14100	2.2043	0.0085	3.5507
Policy 2E	LSS	0	2700	3000	4000	4900	600	15200	2.2139	0.0012	0.4718
Policy 3E	HSS	0	450	3000	3000	6300	1600	14350	2.1890	0.0019	0.7151
Policy 1F	BCS	1200	900	2500	5000	4900	0	14500	2.2163	0.0046	1.91
Policy 2F	LSS	0	3600	2500	1000	5600	1200	13900	2.2953	0.0076	2.9543
Policy 3F	HSS	0	1350	3000	2000	5600	2400	14350	2.2001	0.0033	1.2237

Table A1. Forecasted Peak Demand [18]

Stage (Year)	0	1	2	3	4	5	6	7
Peak (MW)	5000	7000	9000	10000	12000	13000	14000	15000

Table A2.Technical and Economic Data of Candidate Plants (for case I) [18]

Candidate Type	Construction Upper limit	Capacity (MW)	FOR (%)	Operating Cost ($/kWh)	Fixed O&M Cost ($/kw-Mon)	Capital Cost ($/kW)	Life Time (Yrs)
Oil	5	200	7.0	0.021	2.20	812.5	25
LNG C/C	4	450	10.0	0.035	0.90	500.0	20
Coal(Bitum.)	3	500	9.5	0.014	2.75	1062.5	25
Nuc.(PWR)	3	1,000	9.0	0.004	4.60	1625.0	25
Nuc.(PHWR)	3	700	7.0	0.003	5.50	1750.0	25
Solar	3	1000	76	0.001	2.08	3873	25

Table A3.Technical and Economic Data of the Solar Plant (for case II & III) [32]

Plant Type	FOR (%)	Operating Cost ($/kWh)	Fixed O&M Cost ($/kW-Mon)	Capital Cost ($/kW)	Life Time (Yrs)
Solar	76	0.001	2.08	3873	25

Table A4. Technical and Economic Data of Existing Plants [18]

Name (Fuel Type)	No. of Units	Unit Capacity (MW)	FOR (%)	Operating Cost ($/kWh)	Fixed O& M Cost ($/kW-Mon)
Oil#1(Heavy Oil)	1	200	7.0	0.024	2.25
Oil#2(Heavy Oil)	1	200	6.8	0.027	2.25
Oil#3(Heavy Oil)	1	150	6.0	0.030	2.13
LNG G/T#1(LNG)	3	50	3.0	0.043	4.52
LNG C/C#1(LNG)	1	400	10.0	0.038	1.63
LNG C/C#2(LNG)	1	400	10.0	0.040	1.63
LNG C/C#3(LNG)	1	450	11.0	0.035	2.00
Coal#1(Anthracite)	2	250	15.0	0.023	6.65
Coal#2(Bituminous)	1	500	9.0	0.019	2.81
Coal#3(Bituminous)	1	500	8.5	0.015	2.81
Nuclear#1(PWR)	1	1,000	9.0	0.005	4.94
Nuclear#2(PWR)	1	1,000	8.8	0.005	4.63

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