Generation Expansion Planning Using Renewable Energy Sources with Storage

K. Rajesh, A. Ramkumar, and S. Rajendran

Abstract A vital component of maintaining economic growth is the development of the power infrastructure. Most power plants in India are powered by traditional energy sources such as coal, diesel, oil, gas, hydropower, and nuclear power. Numerous techniques for solving the models and resolving the efficiency issue have been put out in recent years. To create a realistic mathematical system and use GEP in the model solutions, the goal of this work is to analyze the GEP for the candidate system by integrating all important system components. The planning of the test system is done for two separate planning horizons, which are 6 and 14 years, respectively. For the same power system, GEP mathematical modeling studies are conducted to examine the effects of the addition of a solar power plant with a storage facility. Based on (a) the investment strategies of introducing solar plants as an alternative candidate plant or as a replacement for existing High Emission Plants (HEP), (b) whether the Solar Plant with Storage (SPWS) or Without Storage (SPWNS) capacity, and (c) inclusion of treatment/penalty costs on emissions from HEP, this is planned in a four-level hierarchy. For anticipated solar penetration levels of 5–10 and 10–20% for 6 and 14 years of planning horizons, respectively, the sensitivity of the system performance elements such as the capacity added, total cost, and Expected Energy Not Served (EENS) is also carried. The system's performance is very dependent on the FOR% that is expected. When SPWS is added to the system as an alternative investment candidate plant, the model studies present an upbeat prospect for power system planning. This study offers a four-level hierarchy to understand the full range of policy issues that may arise in GEP and enables planners to implement situation-specific solutions, while also attempting to illustrate the complexity of the decision-making process when introducing solar plants into an existing system.

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1 Introduction

Due to the temporal and spatial fluctuations in both the supply and demand for energy, generation expansion planning (GEP) is a difficult task. Additionally, a complex mix of alternative candidate plants with various physical and production capabilities and features must be included in the system. The GEP is a large-scale, long-term, non-linear, mixed-variable mathematical modeling issue since all these components are integrated into a system framework. For the development of an effective and affordable power system, the precise solution of such realistic models is crucial. To maintain economic growth, the improvement of the power infrastructure is crucial. In India, most power plants rely on traditional energy sources such coal, diesel, oil, gas, hydropower, and nuclear power. Numerous techniques for solving the models and addressing the efficiency problem have been put forth in recent years.

The objective of this work is to analyze the GEP for the candidate system, integrating all important system components that will result in the development of a plausible mathematical system and the use of GEP in the model solutions. The planning of the test system is done for two separate planning horizons, which are 6 and 14 years, respectively. A special emphasis is placed on examining the effects of such an increase because it is anticipated that the system will contain an increasing number of solar and wind power facilities in the future.

It is examined how to strike a balance between the advantages of increasing solar penetration and the expense of modifying current base load systems. By applying a realistic set of Total Emission Reductions Constraints (TERC) and Emission Treatment Penalty Costs (ETPC) to the remaining amount of pollution, a balanced approach is taken to comprehend the long-term effects of solar additions. Additionally, it is examined how different solar power development and emissions reduction scenarios will affect the system generation mix and system reliability.

A power system faces expansion and operating issues when Renewable Energy Technologies (RET) like solar and wind power facilities are added. Due to the distinctive generation characteristics of these RET plants, earlier studies have shown the requirements for extra backup power facilities required for every installation of RET plants. Power system planners have recently become interested in alternate methods of building power storage facilities using energy from RETs and obtaining reliable supply from such storage facilities. Studies using GEP mathematical modeling are conducted for the same power system to determine how the addition of solar power plants with storage facilities will affect the system. Based on (a) the investment strategies of introducing solar plants as an alternative candidate plant or as a replacement for existing High Emission Plants, this is planned in a four-level hierarchy (HEP) (b) the capacity of either a solar power plant with storage (SPWS) or without storage (SPWNS), and (c) the inclusion of treatment and penalty charges for HEP emissions.

For assumed solar penetration levels of 5–10 and 10–20% for 6- and 14-year planning horizons, respectively, the sensitivity of the system performance factors such as the capacity added, overall cost, and Expected Energy Not Served (EENS) for variations in assumed Forced Outage Rate (FOR%) is also considered. The assumed FOR% has a significant impact on the system performance. When SPWS is added to the system as an alternative investment candidate plant, the model studies present a positive scenario for power system planning. This study offers a four-level hierarchy to understand the full range of policy issues that may arise in GEP and enables planners to adopt situation-specific solutions, while also attempting to illustrate the complexity of the decision-making process when introducing solar plants into an existing system.

2 Overview

Any power system's primary goal is to provide affordable, dependable electricity to all types of consumers, including residential, commercial, industrial, and agricultural ones. The power utilities' main duty is to anticipate future customer demands and carefully plan the installation of additional capacity to meet those demands. The growth of the nation's infrastructure as well as its technological, social, and economic advancements depend heavily on electric energy. The amount of power used per person in a nation indicates its level of development. It also serves as a gauge of a nation's citizens' standard of living. The demand for electricity rises because of economic growth and the related rise in economic activity. Human activities such as industrial production, domestic/residential life, agricultural endeavors, transportation, lighting, and heating all involve the use of electricity. Electric energy cannot be conveniently stored in huge quantities, therefore a constant and nearly immediate balance between production and consumption of power is required. To accommodate fluctuations in demand, some extra generation will be maintained on hand. Load shedding is inevitable if the supply system is unable to keep up with demand. The power shortage might be lessened by the improved installed capacity. The excessive investment and high operational costs could raise the cost of energy, which would then be reflected in the consumer's bill. On the other side, inadequate investment and low generation margins may result in poor customer reliability and a lack of access to power. The most crucial aspects of energy policy are the identification and analysis of energy development as well as the problems of use, distribution, and planning.

Power systems benefit from investments in generation systems. Researchers have proposed GEP to manage generation system planning that is optimal in this regard. Many research projects on GEP have been conducted in recent years. These issues have been researched using various viewpoints, approaches, restrictions, and goals.

The distribution, transmission, and generation sectors can all participate in the expansion of the electric power system. In comparison to TEP and the distribution portion of the power system, the investment in GEP is significantly greater. In terms of reliability, the power system engineers prioritize the increase of generation above the other two sectors. The transmission and distribution networks might be regarded as one of the limits because GEP can be carried out without increasing them. Investors and consumers have long paid close attention to the GEP, which is associated with investments in energy generation. To ensure a profit in this industry and the happiness of the customers, the investment strategy should consider the various aspects of difficulties, such as sizing, timing, the technology of new generating units, investment reversibility, risks, and uncertainties. In GEP, the goal is to increase the current power system to meet future demand growth while maintaining reliability standards at the lowest possible cost. Over a planning horizon of typically 10–30 years, the GEP specifies the size, location, technology, and timing of installing new plants to serve the anticipated load within the specified dependability criteria.

All nations have become increasingly concerned about climate change and emissions since the United Nations Conference on Human Development in Stockholm in 1972, the creation of the Intergovernmental Panel on Climate Change (IPCC), and the adoption of the United Nations Framework Convention on Climate Change (UNFCCC) at the Rio Summit in 1992. As a result, the Kyoto Protocol and the Bali Action Plan were created (BAP). Today, there is a considerable global worry about the threat of climate change brought on by human emissions. The action plan for the growth of every nation on earth reflects it.

Policymakers have adopted policies to encourage investments in low-emissions renewable electricity generation to decarbonize the electric power networks. To balance the load and generation and ensure system reliability, different and more expensive procedures are needed as the use of Renewable Energy Technologies (RET) increases. Two significant problems have resulted because of this: (i) an increase in overall system costs as a result of the required renewable dispatches, and (ii) the offset of emission benefits as a result of the renewable by the ramping and cyclic operations of other plants in the system as suggested by the MIT Energy Initiative [1]. Planning for capacity growth presents a challenge because each technological generation has unique technical and economic characteristics. This makes it difficult to properly integrate these problems into a system architecture.

Due to their unreliability and widespread environmental concerns, many nations around the world are intending to employ wind and solar energy as major replacements for traditional energy produced from fossil fuels. The installed wind power capacity has increased by around 30% annually over the past 10 years. According to the European Wind Energy Association [2], Denmark, Germany, and Spain are the first few nations to produce 20% of their electricity from wind turbines. By the end of 2004, 200,000 off-grid wind turbine generators had been deployed, making industrialized nations like China the world's leaders [3].

There are numerous renewable energy sources available in India. From about 7.8% in 2008 to 12.3% in 2013, RET's share of power systems increased, and by 2017, it is anticipated to reach 17% of all installed capacity. The enormous environmental, social, and economic advantages of wind energy make it a particularly viable alternative for generating electricity. When compared to traditional sources, the behavior of electrical power generation from wind energy is very different. The use of wind energy in grid-connected and stand-alone systems will continue to be encouraged by advancements in wind generation technologies. The reliability difficulties related to wind energy sources must therefore be properly considered by engineers and planners of power systems. One of the fastest-growing sources of energy for humans is the wind, which may also be used to generate fossil fuels and conventional electricity. Wind energy has no associated costs and requires little upkeep. As of the end of March 2017, India's installed wind generating capacity totaled 31.17 GW, a substantial growth over the previous few years.

Solar energy has expanded significantly during the past 10 years in addition to wind energy. The country receives the most amount of solar radiation in the globe due to its extensive landmass. India has enacted several legislative initiatives to encourage investments in low-emissions renewable electricity generation, keeping up with the worldwide trend. The expansion of solar energy potential has been encouraged by the Indian government. By 2013, the installed capacity of solar power plants has expanded to 1683 MW since the Jawaharlal Nehru National Solar Mission (JNNSM) was established in 2009. By 2022, it's anticipated that a combination of rising electricity demand, rising fossil fuel prices, difficulties in obtaining fossil fuels, and favorable environmental legislation will enable solar power capacity to reach more than 50 GW.

Research on assessing the solar and wind energy potential based on irradiation data, the effects of solar and wind energy technologies, and the market potential for investment has only been conducted in a small number of studies. Furthermore, no systematic investigation of the potential combinations of electricity-generating technologies under various future scenarios of solar and wind energy development has been done in India. This might be the case because the unique properties of solar and wind technologies call for specialized data and modeling capabilities. While conventional thermal generators can typically be dispatched within specified operational parameters, the output of solar and wind energy is influenced by the spatial and temporal heterogeneity of solar irradiation. While solar systems can produce electricity without any emissions, their limited capacity to forecast production, store electricity, and manage the supply of renewable energy is likely to have an impact on all levels of electric power system regulation. Between the dispatch point and the root nodes, where the capable generation of renewable energy takes place, there is now confusion and a stark divide. This makes capacity-expansion modeling more complex. No single model study can consider all the many problems involved in simulating solar and wind technology.

A GEP modeling analysis is conducted in this study for a test system to examine the effects of expanding the use of solar and wind power technologies. Long-term investments in conventional technology capacity-expansion modeling technique are used to conduct the analysis of the solar energy portfolio. In order to create an ideal system and aid in the analysis of the operational behaviors of the plants, the model uses a set of presumptive sun penetration levels. It is also done to determine how sensitive the system generation mix is to various solar power development and emissions reduction scenarios (as a replacement for various oil plants and also as a proportional addition to the current system capacity). The differences in reliability indices and other cost components as a result are also reported.

3 Literature Review

The levels of decarbonization targeted for energy in 2050 have been suggested by Ben Haley et al. [4]. Both substantially higher variable renewable penetrations and much stricter restrictions on the use of fossil power for system balancing are possible in low-carbon scenarios. Renewable energy sources, like wind and solar, have the potential to significantly reduce the reliance on fossil fuels and greenhouse gas emissions in the electric sector, according to Paul Denholm et al. [5].

High penetration RETs with affordable energy storage have been proposed by Pandzic et al. [6] in order to address the issues of uncertainty and unpredictability related to renewable energy sources, such as wind and solar power systems. In order to balance the imbalance between renewable energy generators and consumption and/or to store excess renewable energy for later use during low- or no-generation periods, energy storage devices will be required at various locations throughout the power system. Jewell and Hu have spoken about this in [7].

A few approaches that have recently been established to investigate the viability of coordinating electric energy storage (EES) with renewable technology plants have been put forth by Vasconcelos et al. [8]. Depending on the extent of the problems and the context of the applications, different modeling and optimization algorithms for GEP with RET with storage facilities are used.

India intends to significantly increase its use of renewable energy to 175 GW by 2022 to reduce emissions. Intended Nationally Determined Contributions provides details on this (INDCs). To handle the fluctuations in the generation from renewable (green) sources, additional conventional sources with some emissions, such as thermal, must also be present if renewables are to produce such a huge amount of power. Offering generation flexibility entails quick ramping, quick startup, and effective partial load operating in the absence of significant storage. These plants' operations, maintenance schedules, and anticipated operating lifetimes will all suffer if their capacity to ramp and the cycle is increased to various degrees.

The GEP problem, which has been studied by system designers for more than 40 years, has been presented by Francesco et al. [9]. The planners can choose the generation technology, the size of the generation units to be built, and the amount of energy that can be generated by both new and existing plants by solving the GEP problem while considering the limitations on construction times, life-cycle duration, and the total amount of investment.

Because fossil fuels are not sustainable and there are widespread environmental concerns, several nations throughout the world are aiming to employ wind and solar energy as significant replacements for conventional energy. The Global Wind Energy Council (GWEC) discusses how installed wind capacity has grown by around 30% annually over the past 10 years [10]. Future sustainable energy systems are projected to use a greater proportion of renewable energy. In 2007, 94 GW (2.5% of the installed electrical power capacity) came from wind energy [11]. George and Banerjee [12] examined the development of the wind's contribution in numerous grids, which is large in several countries (22% in Denmark, 20% in Spain, 17% in Germany and Portugal, and 8% in the Netherlands).

Techniques for hydropower and fossil fuel plants are provided by conventional power planning. Depending on the site wind regime and machine parameters, the output of a wind power plant varies daily and over the course of the year. The challenges of capacity expansion planning and dispatch become more crucial as wind energy's proportion rises and becomes considerable. It has been investigated how wind energy affects the grid in terms of capacity credit. According to Milligan [13], the degree of a conventional generation that can be replaced by wind generation is known as the capacity credit of wind power.

According to Sharan et al. [14], a clean energy future will necessitate increasing investment in renewable energy sources, which can also offer appealing dividends including job creation, economic growth, energy security, and improved price stability in addition to environmental advantages. As a result, governments all around the world are increasingly focusing on renewable energy. Indian policymakers have supported renewables via tools including the Renewable Purchase Obligation (RPO), Renewable Energy Certificates (REC), Tax Credits, and Generation Based Incentives to decarbonize the electric power systems (GBI). Three major issues arise for generation and grid operations because of the integration of renewable energy sources into current conventional electrical power systems: non-controllable fluctuation, partial unpredictability, and location dependence. The basis for integrating large-capacity Renewable Energy (RE) power into the grid is an understanding of these distinctive characteristics and how they interact with other components of the power system, whereas conventional thermal generators can typically be dispatched within some operational parameters [15]. The external component of sun irradiation affects how much solar power is produced. This irradiance is heterogeneous geographically, temporally, and both.

Correct investment choices, a better regulatory environment, and beneficial government policies will be the results of knowledge regarding the performance of solar power plants [16]. With the aim of estimating the performance of solar power plants at various locations, they have looked at a variety of factors contributing to the performance of solar power plants, including radiation, temperature, and other climatic conditions, design, inverter efficiency, and degradation due to aging. They have also reviewed existing radiation data sources and design criteria for solar power plants.

Using the Google Earth TM application, which offers either satellite photos of building roofs or their number of floors via the Street View feature, Cellular et al. [17] have developed a good approach for the assessment of the photovoltaic potential in urban environments. The methodology's applicability has been examined in a particular urban area of the southern Italian city of Palermo. Understanding rooftop solar energy's potential is the first step in presenting it as a solution. Abhishek Pratap conducted and shared a thorough review of the prospects and hurdles for the efficient deployment of rooftop solar in Delhi city [18].

To consider how solar deployment interacts with the resource sufficiency and operating reliability of the power system, Sullivan et al. [19] have established efficient capacity-expansion models. The system's operating-reliability load and expenses associated with the increased need for ancillary services are increased by the variability and uncertainty of the solar resource and operational characteristics. Some of them are still challenging to solve using current models, therefore they constitute a potential field for further study.

The crucial and unresolved subject of how the extra capacity will be built up and how it's ideal geographic distribution will be projected has been put up by Schroder and Bracke [20]. Particularly, the literature that is now available provides little or only hazy information about transmission networks, the availability of reserve capacity, and the geographic distribution of plants.

Many researchers use capacity expansion models to choose the best generation technologies that can be combined with solar or other renewable technologies. A overview of four main approaches—from straightforward screening-curve calculations to simultaneous capacity expansion modelling of dispatchable and non-dispatchable generators—for incorporating non-dispatchable technologies like solar into capacity-expansion modeling is described in [20]. Numerous researchers have also tested capacity expansion models using renewable energy [21–28].

According to Wang et al. [29], the GEP models split into three main categories: (1) Basic GEP models that determine what technology plants to integrate into the system, when, and how many. They do not offer full operational procedures as model decisions, (2) models deliver detailed operational procedures as a model solution while prioritizing the capacities of prospective plants, and (3) models provide both capacity and operational decisions simultaneously [30]. At various levels of approximation, these models have taken capacity and operational considerations into account. These estimates are either situation- or system-specific. When combining both capacity and operational constraints, there are significant variances in terms of the spatial and temporal resolutions. The placement, timing, and capacity considerations of the various technology plants outlined by Khokhar [30], have also been incorporated into models that aim for a finer resolution of spatial decisions. The geographical and temporal resolutions of models that included intricate operational difficulties also differ, each at the expense of the other.

Recent models that offer RETs as a choice have added operational problems like emissions, ramping, and cyclic problems on top of those relating to conventional plants. While system-specific concerns have driven the choice of a particular model for analysis, situation-specific concerns including data availability, processing power, and the goal of model analysis have also influenced the choice of model type and solution methodology.

According to Balkirtzis et al. [31], the modelling approaches can be divided into two categories: micro and macro. The micro approach uses analytical and sophisticated operational research and meta-heuristics to deal with complex non-linear transmission constraints and reliability criteria, whereas the macroeconomic approach minimizes modeling complexities by ignoring the complex features and constraints within the energy sector, typically with predictable results. Based on model/approach, operation point of view (centralization or decentralization), transmission planning, uncertainties modeled, and implementation time step, they have developed an effective classification of models.

Using Long-range Energy Alternatives Planning (LEAP) software, Karapidakis et al. [24] examined the Crete Island power system under two long-term scenarios (with renewables penetrations of 20 and 50%) in order to calculate the costs and benefits related to the significant high electricity production from RETs in the years 2009–2020.

To discover the compromised solution, Promjiraprawat and Limmeechokcha [26] modeled CO_2 emissions and external cost as a multi-objective optimization problem. They have shown that, using carbon capture and storage technology, CO_2 emissions may be reduced by 74.7% from the least expensive option, which resulted in a 500 billion US dollar decrease in external costs over the planning horizon.

The creation of an Investment Model for Renewable Electricity Systems (IMRES) has been described by Sisternes [25], as an IMRES with unit commitment limitations, where decisions about investment, unit commitment, and energy dispatch are made simultaneously. The model is designed as a 0–1 MILP, taking capacity decisions at the level of each power plant while considering a variety of techno-economic factors, including ramp limits, startup costs, and the minimum steady outputs of thermal plants, among others.

An optimization model that considers several pertinent factors related to Photo Voltaic (PV) projects, such as location-specific solar radiation levels, a precise depiction of investment costs, and an approximation of the transmission system, has been provided by Muneer [27]. A thorough case study of the investment in large-scale solar PV projects in Ontario, Canada, is provided and analyzed to illustrate the value and practicality of the methodology and tools that are suggested.

To calculate the additional transmission capacity and reserve capacity necessary to meet customer demand and maintain grid reliability, the SunShot Vision Study examined the use of the Regional Energy Deployment System (ReEDS) to examine how the electric sector has evolved in meeting the SunShot targets. Based on a variety of variables, including regional solar resource quality, future technology, and fuel price projections, future electricity demand projections, the effects of variability in renewable generation, transmission requirements, and reserve requirements, ReEDS determines where PV, Concentrated Solar Power (CSP), and other generation technologies will be deployed.

An integrated power dispatch and load flow model with endogenous energy generation capacity augmentation has been described by Schroder and Bracke [20]. The goal is to estimate how much generation capacity would be needed in Central Europe by 2030 and where that capacity should be in relation to the planned grid structure. To assess the possibilities for replacing diesel, Rose et al. [21] utilized a system-level model for Kenya that included grid-connected solar PV and pre-existing reservoir hydropower.

With the help of High Voltage Direct Current (HVDC) transmission, Grossmann et al. [28] demonstrated that site selection optimization over sufficiently large geographic areas can address all three causes of intermittency and reduce costs through later optimization of generation capacity and storage. They have provided techniques for converting daily insolation data from NASA's Solar Sizer to hourly scale, which can then be used to evaluate and compare large-scale networks and ultimately improve their generation and storage capabilities. Then, using solar data from 1986 to 2005, these techniques were applied to twelve potential large-scale solar networks in various locations of the world.

A regional action plan for the diffusion of renewable energy technology was evaluated by Beccali et al. [22] using the multicriteria decision-making technique. Sardinia's island has been the subject of a case study. Based on three hypothetical decision scenarios—each of which represents a cohesive set of actions—diffusion strategies have been created.

The quick expansion of solar PV generation has been fueled by factors such as the simplicity of installation, the falling cost of PV technology, and government policy that supports the development of solar energy. With less energy imports, many nations want to lower greenhouse gas emissions and increase energy security. The best way to accomplish these objectives is via renewable energy. By 2020, the European Union wants to use 20% renewable energy.

According to Zervos et al. [6], the renewable energy sector in Europe asserts that by the year 2050, 100% renewable energy will be technologically feasible. China and India are also aiming for a 15% reduction by 2020. 37 of the US's 50 states have guidelines or objectives with percentages ranging from 10 to 40% across various time frames [32].

According to Hand et al. [33] and NREL's primary findings, the US can attain 80% renewable energy by 2050. However, only thorough analyses that include 30% wind energy have supported this theoretical possibility, which is reviewed by Ackermann and Thomas [34].

Due to the erratic and unexpected nature of wind speed, high wind power generation will have a substantial influence on system security, stability, and reliability. The performance and dependability of the electricity grid may be impacted positively or negatively by the integration of numerous wind farms. System operation and system planning are typically the two angles from which the effects of wind power penetration on system security and dependability are examined. Bouffard et al. [35], Chan et al. [36], Lee et al. [37], Schlueter et al. [38], and Soder [39] have developed spinning reserve management with wind power generation for short-term system operation, which shows that spinning reserve from conventional units must be increased with the increased wind power generation to meet the specific reliability and security requirements.

According to Giebel [40], the power system needs for wind power are primarily determined by the configuration of the power system, the installed wind power capacity, and the variability of wind power production. Power systems are impacted by variations in wind resources on time spans ranging from seconds to years. The geographic region of interest will serve as the foundation for an investigation of this influence. In literature, capacity credit has typically been used to describe how wind energy affects the system. The amount of installed renewable capacity by which conventional capacity can be decreased without compromising supply security is known as the capacity credit of wind power.

According to numerous studies [41–44] examining the consequences of grid integration of wind power in European nations, the main difficulties include effects on operational costs, power quality, imbalances, and transmission and schedule planning. According to the results, wind power impacts are minimal at low penetrations (5% or less), and they are still noticeable at penetrations of up to 20%.

The potential and popularity of wind energy as a source of electrical power has led to speculation that it could replace traditional fossil fuels. Ackermann [45] discussed how wind power is predicted to produce a sizeable share of all electrical energy in the years to come. Burke et al.'s [46] recommendation addresses the unfavorable effect of wind farms producing energy in the presence of transmission line constraints. Even if the wind farm must be cut, some of the works recommend that the remaining lines be operated as efficiently as possible.

One of the most frequently brought up issues in relation to operations research is the GEP problem. A forward dynamic programming method had been used to solve the GEP problem in the early 1970s. More focus has been placed on this subject because of the 1980s' improvements in computational techniques and power. Since 2000, more advanced computational methods have been created to address the GEP challenge.

The literature assessment conducted for this study supports the widely held belief that long-term use of non-renewable energy generation systems will result in a fervent demand for the discovery of resources necessary for their operation. A green energy generation plan based on solar and wind energy is an alternative energy generation method that is constantly improving and being warmly welcomed throughout the world. This research focuses on the prior and optimal use of solar and wind-based energy generation schemes alongside more conventional energy-producing facilities that are dependent on oil, LNG, coal, and nuclear resources. The proper analysis and effective application of renewable energy technology (RET), which offers us a proactive solution and functions as a replacement for the decreasing energy supplies that are dependent on energy-producing schemes, are the main foci of this research project.

4 Planning for Lowest Cost Generation Expansion with Solar Plant

There are numerous renewable energy sources available in India. From about 7.8% in 2008 to 12.3% in 2013, RET's share of power systems increased, and by 2017, it is anticipated to reach 17% of all installed capacity. In addition to wind energy, solar energy has expanded significantly over the past 10 years. The country's extensive land area experiences some of the greatest sun radiation levels in the whole world.

India has taken policy measures to encourage investments in renewable electricity generation with low emissions, keeping up with the worldwide trend.

There is no specific reason for restricting the planning horizons to 6 and 14 years. We wanted to have small and medium range effective planning horizons for our studies. The same case studies, solution methods, analysis and techniques can be extended to long range planning horizons too.

In this chapter, a GEP is carried out by using DEA for a system for 6 and 14 years planning horizon with three different scenarios namely BCS, LSS and HSS. In this first scenario (BCS), the GEP is carried out without solar plants and in the second scenario called (LSS), in which solar plants are considered up to 5–10% penetration level.

In third scenario (HSS), penetrations of solar plants are increased to 10–20%.

4.1 GEP Problem Formulation

To meet the energy demand, GEP specifies WHAT, WHEN, and WHERE additional generation units are to be added across the planning timeframes under consideration [30, 47, 48]. Finding a collection of ideal decision vectors across a planning horizon that lowers investment and operating expenses while considering the necessary limitations is what the GEP problem entails. The GEP problem is corresponding to finding a set of optimum decision vectors over a planning horizon that reduces the investment and operating costs under relevant constraints.

4.2 Cost Objective

The cost objective is:

$$\mathrm{M\ in\ C} = \sum_{t=1}^{T} [\mathrm{I}(\mathrm{U_t}) + \mathrm{M}(\mathrm{X_t}) + \mathrm{O}(\mathrm{X_t}) - \mathrm{S}(\mathrm{U_t})] \tag{1}$$

where,

$$\mathrm{X_t} = \mathrm{X_{t-1}} + \mathrm{U_t} \quad (\mathrm{t} = 1, 2, \ldots \mathrm{T}) \tag{2}$$

$$\mathrm{I}(\mathrm{U_t}) = (1 + \mathrm{d})^{-2t} \sum_{t=1}^{N} (\mathrm{CI_i} \times \mathrm{U_{t,i}}) \tag{3}$$

$$\mathrm{S}(\mathrm{U_t}) = (1 + \mathrm{d})^{-\mathrm{T}'} \sum_{t=1}^{N} (\mathrm{CI_i} \times \delta_i \times \mathrm{U_{t,i}}) \tag{4}$$

$$M(X_t) = \sum_{s'=0}^{1}((1+d)^{1.5+t'+s'}(\sum(X_t \times FC) + MC)) \tag{5}$$

$$O(X_t) = EENS \times OC \times \sum_{s'=0}^{1}((1+d)^{1.5+t'+s'}) \tag{6}$$

The outage cost computation of (A.6), applied in (A.1), depends on EENS.

The equivalent energy function method [30] is applied to compute EENS and LOLP. Here, LOLP is used as a constraint.

$$\mathrm{t}^{'} = 2(\mathrm{t}-1)\mathrm{and}\mathrm{T}' = 2 \times \mathrm{T} - \mathrm{t}' \tag{7}$$

Here,

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

4.3 Constraints

The following restrictions should be met by the minimum cost objective function.

4.3.1 Upper Construction Limit

Let U_t describe the units that should be included in the expansion plan at stage t.

$$0 \leq U_t \leq U_{max,t} \tag{8}$$

where,

$U_{max,t}$ maximum construction limit of the units at stage *t*.

4.3.2 Reserve Margin

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

$$(1 + R_{min}) \times D_t \leq \sum_{t=1}^{N} X_{t,i} \leq (1 + R_{max}) \times D_t \tag{9}$$

where,

R_{max} maximum reserve margin;
$X_{(t,i)}$ cumulative capacity of unit i at stage t;
D_t demand at stage t in megawatts (MW);
R_{min} minimum reserve margin.

4.3.3 Ratio of the Fuel Mix

The GEP has generating units that use a variety of fuels, including coal, LNG, oil, nuclear power, and solar power. The fuel mix proportion should be met by the chosen units and the existing units of each kind.

$$\leq /FM^{j}_{max} \quad j = 1, 2 \ldots, N \tag{10}$$

where,

FM^{j}_{min} minimum fuel mix proportion of type *j;*
FM^{j}_{max} maximum fuel mix proportion of type *j;*
j type of the unit (e.g., oil, LNG, coal, nuclear, solar).

4.3.4 Reliability Standard

Along with the current units, the newly introduced units should meet the LOLP reliability standard.

$$\text{LOLP}(X_t) = \varepsilon \tag{11}$$

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

4.3.5 Emission Constraints

The emission constraints are

$$\sum X_{t,j} ec_j < \lambda \tag{12}$$

where,

ec_j is the emission coefficient of type j, λ is the % reduction in total emissions.

The respective emission coefficients for oil, LNG and coal are 0.85, 0.5 and 1.05. The % reduction in total emissions is considered as 10, 20 and 30%.

Table 13 displays the anticipated peak demand for the test system for each step. Tables 14, 15, 16 and 17, respectively, provide the technical and economic information for potential plants, current plants, and solar power plants without and with storage [49–51]. Figure 1 shows the conceptual flow chart for the generation expansion model study.

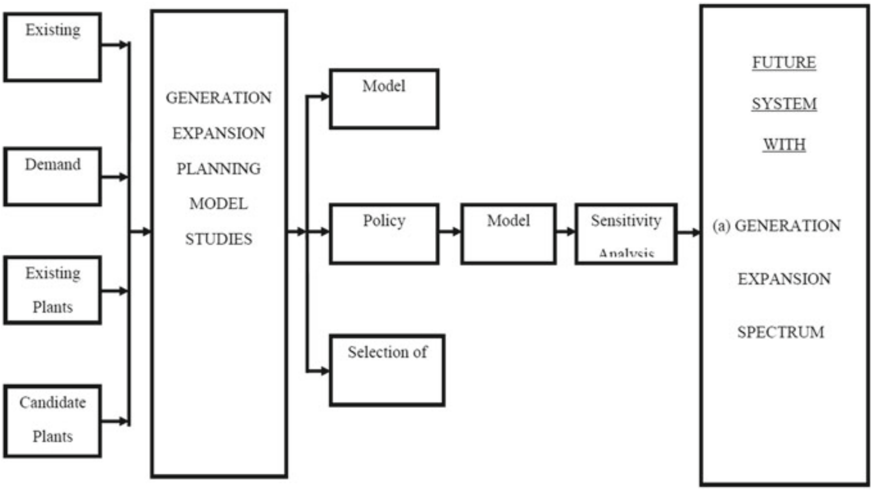

Fig. 1 Schematic flowcharts for the generation expansion model study

4.4 Reliability Indices

The Equivalent Energy Function Method can be used to calculate the reliability indices Loss of Load Probability (LOLP) and Expected Energy Not Served (EENS), as advised in [52, 53].

4.5 Assumptions Made

Reserve margin has defined lower and upper limitations of 20 and 60%, respectively.

- The salvage factor (δ) for oil, LNG, coal, PWR, PHWR and Solar plants are considered as 0.1, 0.1, 0.15, 0.2, 0.2 and 0.1, respectively 0–30.
- 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.
- 8.5% is the set discount rate.
- Two years from the present day is assumed to be the date when the new generation will be accessible. It is assumed that the investment cost will be incurred at the outset of the project.
- The equivalent energy function approach is used to compute the maintenance cost, which is assumed to occur in the middle of the year [52].
- At the conclusion of the planning horizon, the salvage cost is appraised. The constraints are handled using the penalty function method.

4.6 Discussion of the Results

Three possible scenarios of adding solar energy to the system were examined using the model. In the first instance, the BCS, only the existing technology types of plants were taken into consideration as potential candidates for expansion, with solar plants not being considered as a technological alternative. The second was the LSS, where solar power plants with an installed capacity of up to 5–10% were taken into consideration as alternate candidate plants. The third was the HSS, where solar power plants with an installed capacity of up to 10–20% were taken into consideration as alternative candidate plants. The effects of six policy options depending on the addition of TERC, ETPC, or both on the system plants' future generation mix were examined for each scenario. For planning horizons of 6 and 14 years, the analysis was conducted. Below is a breakdown of them, with a summary in Table 1.

Table 1 Scenarios of analysis and policy alternatives for 6- and 14-year planning horizons

Scenario	Policy number	TERC (%)	ETPC*	Solar plants
BCS	1A	0	No	No
	1B	0	Yes	No
	1C	10	No	No
	1D	10	Yes	No
	1E	20	Yes	No
	1F	30	Yes	No
LSS (5–10%)	2A	0	No	Yes
	2B	10	Yes	Yes
	2C	10	No	Yes
	2E	20	Yes	Yes
	2F	30	Yes	Yes
HSS (10–20%)	2A	0	Yes	Yes
	2B	10	No	Yes
	2C	10	Yes	Yes
	2D	20	Yes	Yes
	2F	30	Yes	Yes

* ETPC—Emissions Treatment Penalty Costs (considered equivalent to the total operating costs of the plants) + TERC—Total Emissions Reduction Constraints

4.6.1 Alternatives to Current Policy for the 6- and 14-Year Planning Horizons

Future generation mix with no ETPC and no TERC is the goal of Policies 1A, 2A, and 3A.

Future generation mix with ETPC and no TERC under Policies 1B, 2B, and 2B.

Policies 1C, 2C, and 3C—Future generation mix with only TERC and no ETPC to cut policy 1A's emissions by 10%.

Policies 1D, 2D, and 3D—Future generation mix with ETPC and a cap on overall emissions to cut policy 1A's emissions by 10%. Policies 1E, 2E, and 3E—Future generation mix with ETPC and a cap on overall emissions to cut policy 1A's emissions by 20%.

Policies 1F, 2F, and 3F—Future generation mix with ETPC and a cap on overall emissions to cut policy 1A's emissions by 30%.

BCS policy 1A, in which neither an ETPC nor a TERC is considered in the analysis, is used as the reference example to compare the effects of other policies on the system. For simplicity, nuclear (PWR), nuclear (PHWR), and solar plants are classified as Low Emission Plants (LEP), while oil, LNG, and coal plants are categorized as High Emission Plants (HEP). However, in the respective examples in Tables 2 and 3, the division of individual plants into these two kinds is also provided.

Table 2 For all policy options within the 6-year planning horizon, model solutions for BCS, LSS, and HSS are provided

Policy alternative	Scenario	Oil (MV)	LNG (CC)	Coal (Bitum.) (MW)	HEP (%)	Nuc (PWR) (MW)	Nuc (PWR) (MW)	Solar (MW)	LEP (%)	Added capacity (MW)	Cumulative capacity (MW)	Overall cost × 1010 (s)	EES × 104 (MWh)
1A	BCS	2000	2250	1500	73.25	0	2100	0	26.75	7850	13,300	1.2009	2.7165
1B		2000	2250	1500	73.25	0	2100	0	26.75	7850	13,300	1.2947	2.7165
1C		1400	1800	1500	58.025	2000	1400	0	41.975	8100	13,550	1.2773	3.0475
1D		1400	1800	1500	58.025	2000	1400	0	41.975	8100	13,550	1.3187	3.0475
2E		800	1350	1500	44.785	1000	3500	0	55.215	8150	13,600	1.3442	2.2878
2F		1000	450	3000	53.939	1000	2800	0	46.061	8250	13,700	1.33709	4.0013
2A	LSS	800	2250	2500	62.011	1000	1400	1000	37.778	8950	14,400	1.4180	3.3317
2B		400	2700	2500	62,222	1000	1400	1000	43.243	9000	14,450	1.6139	3.2326
2C		600	3150	1500	56.757	3000	0	1000	51.087	9250	14,700	1.6253	3.0184
2D		1200	1800	1500	48.913	3000	700	1000	54.839	9200	15,500	1.6647	2.9481
2E		0	2700	1500	45.161	2000	2100	1000	54.839	9300	15,500	1.8948	2.3057
2F		0	1350	1500	30.811	4000	1400	1000	69.189	9250	15,350	1.9339	3.8368
3A	HSS	600	2250	2500	53.234	2000	700	2000	46.776	10,050	15,600	1.9934	3.2582
3B		200	3150	2000	53.234	2000	700	2000	46.776	9900	15,600	1.9783	3.6022
3C		600	1800	2000	44.444	0	3500	2000	55.556	10,150	14,850	2.0034	2.5630
3D		200	2250	2000	43.842	3000	700	2000	56.158	10,150	15,600	1.9369	3.5039
3E		0	1350	2000	33.005	2000	2800	2000	66.995	10,150	15,600	1.9783	2.7848
3F		0	0	1000	10.638	5000	1400	2000	89.362	9400	14,850	2.0034	3.1381

Table 3 For all policy options within the 14-year planning horizon, model solutions for BCS, LSS, and HSS are provided

Policy alternative	Scenario	Oil	LNG	Coal (Bitum.)	HEP	Nuc (PWR)	Nuc (PHWR)	Solar	LEP	Added capacity	Cumulative capacity	Overall cost × 1010	LOLP	EES × 104
1A	BCS	2000	2250	5500	70.397	2000	2100	0	29.603	13,850	19,300	2.1811	0.0098	3.8012
1B		1200	1800	4500	53.571	3000	3500	0	46.429	14,000	19,450	2.2627	0.0088	3.6376
1C		1000	450	4000	37.201	5000	4200	0	62.799	14,650	20,100	2.1237	0.0038	1.5245
1D		1000	1350	2500	33.333	2000	7700	0	66.666	14,550	20,000	2.2035	0.0026	0.9825
1E		800	900	3500	36.879	4000	4900	0	63.121	14,100	19,550	2.2043	0.0085	3.5507
1F		1200	900	2500	31.724	5000	4900	0	68.276	14,500	20,500	2.2163	0.0046	1.9100
2A	LSS	1200	2250	2500	39.535	5000	2100	2000	60.465	15,050	21,350	2.6087	0.0091	3.8952
2B		1800	1800	3500	44.654	4000	2800	2000	55.346	15,900	22,250	2.6537	0.0096	3.9875
2C		600	0	3000	21.429	7000	4200	2000	78.571	16,800	21,900	2.7897	0.0023	0.9535
2D		400	450	3000	23.404	5000	5600	2000	76.596	16,450	22,500	2.7937	0.0046	1.9103
2E		0	450	2500	17.302	10,000	2100	2000	82.698	17,050	22,300	2.8237	0.0034	1.5490
2F		400	1350	2500	25.223	5000	5600	2000	74.777	16,800	22,450	2.8506	0.0023	0.9296
3A	HSS	3000	2700	2500	48.235	3000	2800	3000	51.765	17,000	22,500	2.9874	0.0056	2.1771
3B		4000	2250	2000	48.387	3000	2800	3000	51.613	17,050	22,250	3.0641	0.0045	1.6852
3C		600	1800	3500	35.119	3000	4900	3000	64.881	16,800	23,050	3.1480	0.0100	4.1695
3D		600	2700	3500	38.636	5000	2800	3000	61.364	17,600	15,600	3.1733	0.0035	1.4182
3E		1000	0	3500	24.064	6000	4200	4000	75.936	18,700	24,150	3.4128	0.0028	1.1460
3F		800	1350	2500	26.496	5000	4900	3000	73.504	17,550	23,000	3.3100	0.0035	1.4186
		MV	CC	MW	%	MW	MW	MW	%	MW	MW	s	Day/ year	MWh

4.7 BCS—Model Solutions

Tables 2 and 3 provide the model solutions for each of the six above-proposed policy alternatives (from 1A to 1F), for both the 6- and 14-year planning periods, respectively.

4.7.1 Policy 1A Results

For the reference BCS policy 1A, the total cost of meeting the system's demand over a 6-year planning horizon was $1.20091010; the proportions of HEP and LEP were 73.25 and 26.75%; the LOLP and EENS were 0.0086 days/year and 2.7165104 MWh; and the capacity added to the system was 7850 MW, bringing the total installed capacity of the system to 13,300 MW.

The Base Case Scenario (BCS) considered in all the cases of our thesis work is already available in the literature. Kannan et al. [54] applied and compared eight Meta-heuristic techniques with dynamic programming. The DP is one of the standards and popular conventional optimization techniques, which produces an optimal solution in each run. In other words, the success rate of DP in producing optimal solutions is 100%. For our BCS, the optimal solution for 6 years planning horizon is 1.2009×10^{10}. The DEA produces this result with a 100% success rate using the parameters assigned in this thesis work. Hence, we ensured that DEA produces the optimal solution for all the case studies considered.

Figure 2 denotes the convergence plot of the BCS. Our focus is to analyze the impact of various policies upon the GEP, rather than applying various algorithms to GEP. Hence, we have provided the convergence plot for the BCS only.

The total cost to meet the demand of the system for the reference BCS policy 1A over a 14-year planning horizon was $2.18111010; the proportions of HEP and LEP were 70.397% and 29.603%; the LOLP and EENS were 0.0098 days/year and 3.8012104 MWh; and the capacity added to the system was 13,850 MW, bringing the total installed capacity to 19,300 M.

4.7.2 Results of Policy 1B

The total cost to meet the demand of the system for the BCS policy 1B over a 6-year planning horizon was $1.29471010; the proportions of HEP and LEP were 73.25 and 26.75%; the LOLP and EENS were 0.0086 days/year and 2.7165104 MWh; and the capacity added to the system was 7850 MW, bringing the total installed capacity to 13,300 MW.

The total cost to meet the system's demand for the BCS policy 1B over a 14-year planning horizon was $2.26271010; the proportions of HEP and LEP were 53.571 and 46.429%; the LOLP and EENS were 0.0088 days/year and 3.6376104 MWh;

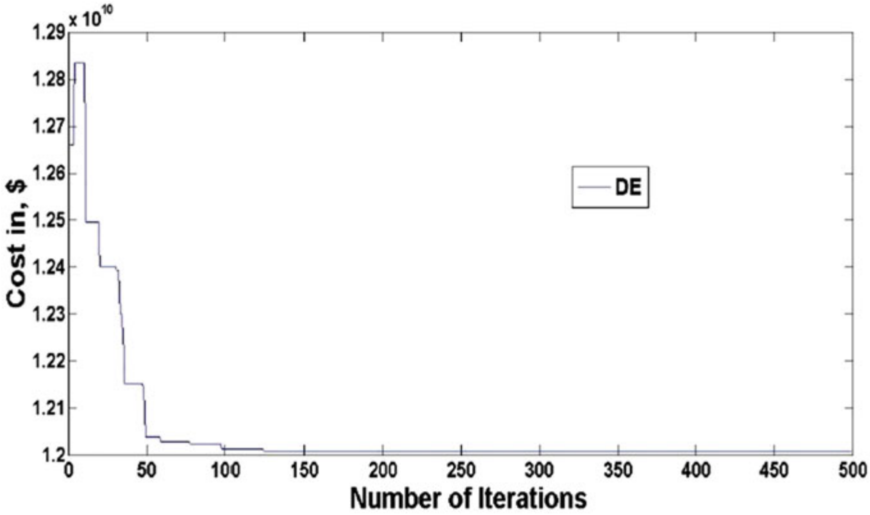

Fig. 2 Convergence plot of the DEA for 6-year planning horizon (BCS)

and the capacity added to the system was 14,000 MW, bringing the installed capacity to a total of 19,450 MW.

4.7.3 Results of Policy 1C

The total cost to meet the demand of the system for BCS policy 1C over a 6-year planning horizon was $1.27731010; the proportions of HEP and LEP were 58.025 and 41.975%; the LOLP and EENS were 0.0088 days/year and 3.0475104 MWh; and the capacity added to the system was 8100 MW, bringing the total installed capacity to 13,550 MW.

The total cost to meet the demand of the system for BCS policy 1C over a 14-year planning horizon was $2.12371010; the proportions of HEP and LEP were 37.201 and 62.799%; the LOLP and EENS were 0.0038 days/year and 1.5245104 MWh; and the capacity added to the system was 14,650 MW, bringing the total installed capacity to 20,100 MW.

4.7.4 Results of Policy 1D

The total cost to meet the demand of the system for BCS policy 1D over a 6-year planning horizon was $1.31871010; the proportions of HEP and LEP were 58.025 and 41.975%; the LOLP and EENS were 0.0088 days/year and 3.0475104 MWh; and the capacity added to the system was 8100 MW, bringing the total installed capacity to 13,550 MW.

The total cost to meet the demand of the system for BCS policy 1D over a 14-year planning horizon was \$2.20351010; the proportions of HEP and LEP were 33.333 and 66.667%; the LOLP and EENS were 0.0026 days/year and 0.9825104 MWh; and the capacity added to the system was 14,550 MW, bringing the installed capacity to 20,000 MW overall.

4.7.5 Results of Policy 1E

The total cost to meet the demand of the system for BCS policy 1E over a 6-year planning horizon was \$1.34421010; the proportions of HEP and LEP were 44.785 and 55.215%; the LOLP and EENS were 0.0067 days/year and 2.2878104 MWh; and the capacity added to the system was 8150 MW, bringing the installed capacity to a total of 13,600 MW.

The total cost to meet the demand of the system for BCS policy 1E over a 14-year planning horizon was \$2.20431010; the proportions of HEP and LEP were 36.879 and 63.121%; the LOLP and EENS were 0.0085 days/year and 3.5507104 MWh; and the capacity added to the system was 14,100 MW, bringing the total installed capacity to 19,550 MW.

4.7.6 Results of Policy 1F

For the BCS policy 1F, the total cost of meeting the system's demand over a 6-year planning horizon was \$1.37091010; the proportions of HEP and LEP were 53.939 and 46.061%; the LOLP and EENS were 0.0107 days/year and 4.0013104 MWh; and the capacity added to the system was 8250 MW, bringing the total installed capacity of the system up to 13,700 MW.

The total cost to meet the demand of the system for BCS policy 1F over a 14-year planning horizon was \$2.21631010; the proportions of HEP and LEP were 31.724 and 68.276%; the LOLP and EENS were 0.0046 days/year and 1.9100104 MWh; and the capacity added to the system was 14,500 MW, bringing the total installed capacity to 19,950 MW.

4.8 LSS—Solutions of the Model

Tables 2 and 3 provide the model solutions for each of the six policy possibilities (2A to 2F) put forward above, for both the 6- and 14-year planning periods, respectively.

4.8.1 Results of Policy 2A

The reference LSS policy 2A's overall cost to meet demand over a 6-year planning horizon was $1.41801010; the proportions of HEP and LEP were 62.011 and 37.989%, respectively; the LOLP and EENS were 0.0096 and 3.3317 days/year, respectively.

4.8.2 The Highlights of Model Solutions Are

- The implementation of ETPC or TERC or both allowed for a balanced approach between the high emissions base load facilities and the low emissions peak load plants.
- For a variety of policy options, the effect of the addition of solar plants on the plant mix and system reliability was researched.
- The generating mix and the reliability factors were very responsive to the system's emission reduction policies. For all of the policy actions outlined, the influence on the system-generating mix led to lower overall costs and improved system reliability.
- With the addition of solar plants to the system, both the installed capacity and overall prices have increased. The system reliability has also increased.
- Why Higher additions in nuclear plants helped lower overall costs given the make-up of system technology choices at the time TERC was launched, However, because of LEP capacity restrictions, TERC values above 20% did not increase system variables.
- Compared to the scenario where they are not considered, the introduction of ETPC and/or TERC has increased the total system costs in all BCS, LSS, and HSS policy choices. The total costs were lower for the scenarios where just TERC was taken into consideration than for the scenario where we incorporated only ETPC.
- When solar plants were added to the system as a capacity alternative in LSS and HSS, the overall capacity added to the system increased more than the capacity of the solar plants added to the system, regardless of whether ETPC and TERC were considered or not. This was mostly caused by the discontinuous character of plant capacity.
- There were continuous increases in the incremental additions to the system greater than the capacity added by the solar plants when both ETPC and various levels of TERC were adopted for all policy alternatives, in both LSS and HSS, for both the 6- and 14-year planning periods. When we tightened the restrictions to lower the emission levels, the incremental additions outweighed the added solar capacity, requiring more baseload backup and costing more money.
- When we incorporated TERC, the reduction in the HEP was higher than when we only took ETPC into account for all policy choices, including BCS, LSS, and HSS. The LEP plants were unable to offset their hefty capital expenditures.
- The quantity of EENS, in general, decreased significantly for all policy alternatives across BCS, LSS, and HSS when the TERC with higher levels of emissions

reduction and in situations where incremental capacity additions were higher than the reference scenario, of course at a cost.

4.8.3 Scenario Based Analysis

For the BCS, the fraction of HEP ranges from 44.785 to 73.25% and the proportion of LEP plants ranges from 26.75 to 55.215% (Tables 42 and 43). HEP's share in the LSS ranges from 30.811 to 62.222%, and LEP plants' share is from 37.778 to 69.189%. The proportions of HEP and LEP plants in the HSS range from 10.638 to 53.234% and 46.776 to 89.362%, respectively. The range of HEP and LEP fluctuations is lowest for BCS and highest for HSS for the 6-year planning period, whereas the reverse is true for the 14-year planning horizon.

For the 6-year planning horizon, the total system costs for different policy measures varies from $\$1.2009 \times 10^{10}$ to $\$1.3709 \times 10^{10}$, giving a range of $\$0.17 \times 10^{10}$ for BCS; varies from $\$1.4180 \times 10^{10}$ to $\$1.6647 \times 10^{10}$, giving a range of $\$0.2467 \times 10^{10}$ for LSS; and varies from $\$1.8948 \times 10^{10}$ to $\$2.0034 \times 10^{10}$, giving a range of $\$0.1086 \times 10^{10}$ for HSS. For the 14-year planning horizon, the total system costs for different policy measures varies from $\$2.1811 \times 10^{10}$ to $\$2.2163 \times 10^{10}$, giving a range of $\$0.0352 \times 10^{10}$ for BCS; varies from $\$2.6087 \times 10^{10}$ to $\$2.8506 \times 10^{10}$, giving a range of $\$0.2419 \times 10^{10}$ for LSS; and varies from $\$2.9874 \times 10^{10}$ to $\$3.3100 \times 10^{10}$, giving a range of $\$0.3226 \times 10^{10}$ for HSS. For the LSS over a 6-year period and for the HSS over a 14-year period, the variances in overall expenses are greater. In the case of BCS, the total cost differences are minimal throughout the 6- and 14-year periods. This demonstrates how adding solar to the system makes it more susceptible to the policy actions.

For the 6-year planning horizon, the EENS for different policy measures varies from 2.7165×10^4 to 4.0013×10^4 MWh, giving a range of 1.2848×10^4 MWh for BCS; varies from 3.3317×10^4 MWh to 3.8368×10^4 MWh, giving a range of 0.5051×10^4 MWh for LSS; and varies from 3.1381×10^4 MWh to 3.2582×10^4 MWh, giving a range of 0.1201×10^4 MWh for HSS. For the 14-year planning horizon, the total EENS for different policy measures varies from 1.9100×10^4 to 3.8012×10^4 MWh, giving a range of 1.8912×10^4 MWh for BCS; varies from 0.9296×10^4 to 3.8952×10^4 MWh, giving a range of 2.9656×10^4 MWh for LSS; and varies from 1.4186×10^4 to 2.1771×10^4 MWh, giving a range of 0.7585×10^4 MWh for HSS. The variations in LOLP and EENS are also more sensitive to the policy variations when solar is included as an alternative. For the 6- and 14-year periods, respectively, the EENS variation range is considerable for the BCS.

4.8.4 A Mix of Generation and Overall System Costs

For the BCS, the total capacity additions to the system for all six policies range from 7850 to 8250 MW throughout the course of the planning horizon of 6 years. The combined capacity addition for policies 1A and 1B is 7850 MW. The generation mix was the same in both circumstances. However, because we included the ETPC for the plants, the system's overall expenses have increased. The total system costs have increased from \$1.20091010 to \$1.29471010 since the implementation of ETPC. Policy 1C reduces the TERC by 10% compared to policy 1A while increasing total capacity from 7850 to 8100 MW. In policy 1D, where ETPC and TERC are both established, the generation mix was the same as it was in policy 1C. In this instance, there is an increase in the system's overall costs from \$1.2773 to \$1.3187 because of these rules. In addition to ETPC, TERC is introduced for policies 1E and 1F with the goals of 20 and 30% emissions reduction, resulting in policy 1A. The total additional capacity built into the system for these two scenarios is 8150 and 8250 MW, respectively. The sum of the additions' expenses is \$1.3442 1010 and \$1.3709 1010.

4.8.5 System's Reliability

The LOLP and EENS values for all the policy choices across BCS, LSS, and HSS are comparatively low for the 14-year Planning period than the LOLP and EENS values of identical policy alternatives of the 6-year planning period, according to research conducted for 6- and 14-year planning horizons.

The BCS's EENS has the lowest values for the policies (1E and 2E), where ETPC and TERC are targeted at 20%, for the 6- and 14-year planning periods.

For all three of the envisioned situations, the system's LOLP and EENS dependability factors are extremely sensitive to the system generation mix. The greatest value of EENS for LSS is higher than for the BCS and HSS in the scenario where neither ETPC nor TERC are considered. The EENS for HSS is highest when only the ETPC is considered in the model analysis when compared to the other two scenarios.

5 Generation Expansion Planning Based on Solar Plants with Storage

As part of two investment methods for solar plant additions—either as a substitute for oil plants or as an alternative candidate plant for investment—an effort is made to analyze the long-term effects of increasing additions of solar plants into a system. Furthermore, a study on the adoption of solar technologies with built-in storage is elaborated.

The chapter also covers how the introduction of treatment/penalty charges may affect high-emission plant emissions. This chapter also attempts a variant by analyzing the effects of various FOR% combinations for SWPNS and SWPS on system performance. The GEP problem is solved using the DEA with various amounts of solar power penetration.

Two different types of solar plants are taken into consideration for integration into the GEP problem under research. They are Solar Power with Storage and Solar Plant with No Storage (SPWNS) (SPWS). For SPWNS, the FOR% is predicated at 76%, and for SPWS, it is predicated at 6%. All the plants are divided into two categories: LEP (nuclear and solar) and HEP (oil, LNG, and coal).

5.1 Analysis of Model

Four levels of hierarchies are used to structure the GEP model analysis. Figure 3 provides a schematic diagram of the model analyses. The GEP of the system is considered at the first level without the inclusion of solar plants. In the second level, two distinct cases are taken into consideration based on the plan for the introduction of solar power plants, either as an alternative to oil plants or as a potential source of alternative investment. Based on whether the solar power plants had their own storage capacity or not, two different instances are further examined in the third level. In the fourth level, the GEP of the system is subjected to sensitivity analysis for various combinations of (a) solar penetration limits (5–10 or 10–20%), (b) treatment/penalty costs for emissions from HEP (with or without costs), and (c) FOR assumed for SPWNS and SPWS, for both 6- and 14-year planning horizons.

Table 4 provides an overview of the policy options that were taken into consideration for the 6- and 14-year planning periods.

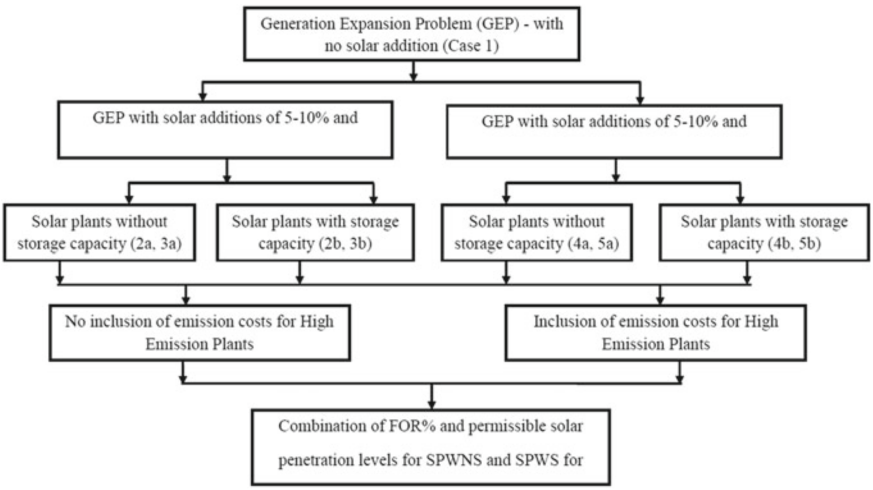

Fig. 3 Schematic diagram of the four levels GEP model analysis

Table 4 Summary of policy cases for SPWNS and SPWS

S1. No.	Summary of policy cases	
1	Case 1	GEP without solar plants
2	Case 2a	5–10%—RES penetration/SPWNS replacing oil plants
3	Case 2b	5–10%—RES penetration/SPWS replacing oil plants
4	Case 3a	10–20%—RES penetration/SPWNS replacing oil plants
5	Case 3b	10–20%—RES penetration/SPWS replacing oil plants
6	Case 4a	5–10%—RES penetration/SPWNS as an alternative investment candidate
7	Case 4b	5–10%—RES penetration/SPWS as an alternative investment candidate
8	Case 5a	10–20%—RES penetration/SPWNS as an alternative investment candidate
9	Case 5b	10–20%—RES penetration/SPWS as an alternative investment candidate

5.2 Results and Discussion

Nine alternative policy case studies are conducted, as shown in Table 4, with the first instance being the case where no consideration of solar addition is made. The remaining eight examples concern studies that incorporate solar plants in the system; two cases deal with the investment plan to substitute solar plants for oil plants, and two cases look at solar plants as a potential alternative investment. The two categories above were divided into two subcategories based on whether the solar plants had storage capacity for the solar penetration levels of 5–10 and 15–20%, respectively. For the anticipated FOR% of 76% for SPWNS and 6% for SPWS, all policy scenarios are examined. Tables 5 and 6 provide the model solutions for the 6-year planning horizon, while Tables 7 and 8 provide the same information for the 14-year planning horizon.

5.3 Case 1: GEP Without Solar Plants

For the assumed demand pattern, capacities of candidate plants for investments, and other factors, when no treatment and penalty costs were imposed on emissions from HEP, the additional installed capacity for the system for the 6-year planning period was 7850 MW, with a breakup between HEP and LEP, respectively, of 5750 and 2100 MW. Oil, LNG, and coal plants each have an additional capacity of 2000, 2250, and 1500 MW for the HEP. Nuclear plants had an additional installed capacity of 2100 MW across the LEP sites. The overall capacity added to the system at the end of the planning horizon was 7850 MW, the total system costs were \$1.20091010, and the EENS was 2.7165104 MWh. The corresponding numbers were 13,850 MW, \$2.1811 10^{10}, and 3.8012 10^{4} MWh for the 14-year planning period.

The additional installed capacity for the system was the same as that of the policy with no treatment and penalty costs applied when treatment and penalty costs

Table 5 Without emission costs: generation mix, Overall costs, LOLP and EENS for 6-year

Policy	Oil (MV)	LNG C/ C(MW)	Coal (Bi-tum) (MW)	Nuc. (PWR)	Nuc. (PHWR) (MW)	Solar (MW)	Added	Cumulative Cap (MW)	Overall cost $\times 10$\$	LOLP (days/year)	EENS $\times 10$ (MWh)
Case1	2000	2250	1500	0	2100	0	7850	13,300	1.2009	0.0086	2.7165
Case2a	0	3600	2000	1000	1400	200	8200	13,650	1.2627	0.0098	3.4470
Case2b	0	2250	3000	2000	700	200	8150	13,450	1.2812	0.0096	3.4435
Case3a	0	2250	3000	2000	700	1000	8950	13,600	1.4702	0.0093	3.3015
Case3b	0	1800	3000	1000	1400	800	8000	13,450	1.5131	0.0093	3.2424
Case4a	1600	2250	1500	2000	700	1000	9050	14,500	1.5208	0.0086	2.1755
Case4b	2000	1800	1500	1000	1400	1000	8700	14,150	1.7130	0.00093	3.1173
Case5a	1400	1350	2500	2000	700	2000	9950	15,400	1.8296	0.0098	3.4713
Case5b	2000	1350	1500	2000	700	2000	9950	15,000	2.2248	0.0100	3.4951

Table 6 With emission costs: generation mix, overall costs, LOLP and EENS for 6-year period (FOR 76 and 6%)

Policy	Oil (MV)	LNG C/C (MW)	Coal (Bi-tum) (MW)	Nuc. (PWR)	Nuc. (PHWR) (MW)	Solar (MW)	Added	Cumulative Cap (MW)	Overall cost $\times 10\$$	LOLP (days/year)	EENS $\times 10$ (MWh)
Case1	2000	2250	1500	0	2100	0	7850	13,300	1.2947	0.0086	2.7165
Case2a	0	3150	3000	1000	1400	200	8750	14,200	1.2974	0.0083	2.9273
Case2b	0	2700	3000	0	2100	200	8000	13,450	1.3187	0.084	2.8275
Case3a	0	2700	3000	2000	700	1000	9400	14,850	1.5283	0.0093	3.4157
Case3b	0	1800	3000	1000	1400	800	8000	144,450	1.5370	0.0086	3.2424
Case4a	400	2700	2500	1000	1400	1000	9000	14,200	1.6139	0.0092	3.2323
Case4b	1600	2250	1500	1000	1400	1000	8750	15,500	1.7156	0.00089	2.7174
Case5a	200	3150	2000	2000	700	2000	10,050	22,200	1.9339	0.0099	3.6622
Case5b	1200	2700	2000	2000	700	2000	9700	15,150	2.2286	0.0086	2.9569

Table 7 Without emission costs: generation mix, overall costs, LOLP and EENS for 14-year period (FOR 76 and 6%)

Policy	Oil (MV)	LNG C/C (MW)	Coal (Bi-tum) (MW)	Nuc. (PWR)	Nuc. (PHWR) (MW)	Solar (MW)	Added	Cumulative Cap (MW)	Overall cost ×10$	LOLP (days/year)	EENS ×10 (MWh)
Case1	2000	2250	5000	2000	2100	0	13,850	19,300	2.1811	0.0098	3.8012
Case2a	0	1800	4000	7000	1400	600	14,800	20,250	2.3011	0.0094	0.4211
Case2b	0	1350	3500	6000	2800	600	14,250	19,700	2.3503	0.0073	3.1486
Case3a	0	2700	6000	3000	2100	1800	15,600	21,050	2.4580	0.0071	2.9172
Case3b	0	2250	3500	4000	3500	2000	15,250	20,700	2.4868	0.0009	0.3294
Case4a	2400	3150	3500	3000	2100	2000	16,150	21,600	2.6263	0.0052	2.0032
Case4b	1400	2250	4000	1000	4900	1000	14,550	20,000	2.7653	0.00097	3.7616
Case5a	2200	2250	4500	2000	2800	3000	16,750	22,200	2.9877	0.0085	3.7616
Case5b	1400	2700	3500	4000	2800	3000	17,400	22,850	3.2026	0.0016	0.5760

Table 8 With emission costs: generation mix, overall costs, LOLP and EENS for 14-year period (FOR 76 and 6%)

Policy	Oil (MV)	LNG C/C (MW)	Coal (Bi-tum) (MW)	Nuc. (PWR) (MW)	Nuc. (PHWR) (MW)	HEP	Solar (MW)	LEP	Added	Cumulative Cap (MW)	Overall cost ×10$	LOLP (Days/year)	EENS × 10 (MWh)
Case1	1200	1800	4500	3000	3500	3500	0	14,000	19,450	2.2627	0.0.00888	0.0088	3.6376
Case2a	0	1800	5000	7000	700	700	600	15,100	20,550	2.3156	0.0059	0.0059	2.5915
Case2b	0	3150	4000	7000	0	0	600	14,750	20,200	2.3603	0.0047	0.0047	2.0383
Case3a	0	2700	4000	4000	3500	3500	1600	15,800	21,250	2.4613	0.0091	0.0091	3.9124
Case3b	0	2250	3500	2000	4900	4900	1400	14,050	19,500	2.5017	0.0065	0.0065	2.5246
Case4a	1800	1800	3500	4000	2800	2800	2000	15,900	21,350	2.6537	0.0096	0.0096	3.9875
Case4b	1800	2250	4500	0	4900	4900	1000	14,450	19,900	2.7654	0.0094	0.00094	3.5604
Case5a	4000	2250	2000	3000	2800	2800	3000	17,050	22,500	3.0641	0.0045	0.0045	1.6842
Case5b	1400	900	4000	3000	4900	4900	3000	17,200	22,650	3.2308	0.0015	0.0015	0.6598

were imposed on emissions from HEP, for the expected demand pattern, capacities of candidate plants for investments, and other criteria. At the conclusion of the planning horizon, the system's new capacity totaled 7850 MW, its expenses totaled \$1.2947 10^{-10}, and its EENS was 2.7165 10^{-4} MWh. The corresponding numbers were 14,000 MW, \$2.2627 10^{10}, and 3.6376 10^{4} MWh for the 14-year planning period.

5.4 Case 2a: 5–10% RES Penetration/SPWNS Replacing Oil Plants

The total capacity added to the system over the 6-year period was 8200 MW, with LNG, coal, nuclear (PWR), nuclear (PHWR), and solar plants adding, respectively, 3600, 2000, 1000, 1400, and 200 MW. During this time, no treatment or penalty fees were imposed on HEP emissions. The EENS was 3.4470×10^{4} MWh, while the total system expenses were \$$1.2627 \times 10^{10}$ MWh.

The total capacity added to the system for the 14-year period was 14,800 MW, with LNG, coal, nuclear (PWR), nuclear (PHWR), and solar plants having respective added capacities of 1800, 4000, 7000, 1400, and 600 MW. During this time, no treatment or penalty costs were imposed on emissions from HEP. The total cost of the system was \$2.3011 10^{10}; the EENS was 0.0094 10^{4} MWh.

The total capacity added to the system for the 6-year period was 8750 MW, with increased capacities for LNG, coal, nuclear (PWR), nuclear (PHWR), and solar plants totaling 3150, 3000, 1000, 1400, and 200 MW, respectively. The total cost of the system was \$1.2974 10^{10} dollars, and the EENS was 2.9273 10^{4} MWh.

The overall capacity added to the system for the 14-year period, when treatment/penalty fees were placed on emissions from HEP, was 15,100 MW, with increased capacities for LNG, coal, nuclear (PWR), nuclear (PHWR), and solar plants of respectively 1800, 5000, 7000, 700, and 600 MW. The EENS was 2.5915104 MWh, and the overall system expenses were \$2.31561010.

5.5 Case 2b: 5–10% RES Penetration/SPWS Replacing Oil Plants

The total capacity added to the system for the 6-year period was 8150 MW, with LNG, coal, nuclear (PWR), nuclear (PHWR), and solar plants having respective added capacities of 2250, 3000, 2000, 700, and 200 MW. During this time, no treatment or penalty costs were imposed on emissions from HEP. The total cost of the system was \$1.2812 10^{10} dollars, and the EENS was 3.4435 10^{4} MWh.

The total capacity added to the system for the 14-year period was 14,250 MW, with LNG, coal, nuclear (PWR), nuclear (PHWR), and solar plants having respective added capacities of 1350, 3500, 6000, 2800, and 600 MW. During this time, no treatment or penalty costs were imposed on emissions from HEP. The system's total expenses came to \$2.3503 10^{10} dollars, and the EENS was 3.1486 10^4 MWh.

The overall capacity added to the system for the 6-year period, when treatment/penalty fees were imposed on HEP emissions, was 8000 MW. LNG, coal, nuclear (PWR), nuclear (PHWR), and solar plants had respective new capacities of 2700, 3000, 0, 2100, and 200 MW. The EENS was 2.8275 10^4 MWh, while the entire system expenses were \$1.3187 10^{10} in total.

The overall capacity added to the system for the 14-year period, when treatment/penalty fees were placed on emissions from HEP, was 14,750 MW, with increased capacities for LNG, coal, nuclear (PWR), nuclear (PHWR), and solar plants of 3150, 4000, 7000, 0, and 600 MW, respectively. The EENS was 2.0383104 MWh, and the total system cost was \$2.36031010.

5.6 Case 3a: 10–20% RES Penetration/SPWNS Replacing Oil Plants

The total capacity added to the system for the 6-year period was 8950 MW, with LNG, coal, nuclear (PWR), nuclear (PHWR), and solar plants having respective added capacities of 2250, 3000, 2000, 700, and 1000 MW. During this time, no treatment or penalty costs were imposed on emissions from HEP. The EENS was 3.3015104 MWh, and the entire system expenses were \$1.47021010.

The total capacity added to the system for the 14-year period was 15,600 MW, with LNG, coal, nuclear (PWR), nuclear (PHWR), and solar plants having respective added capacities of 2700, 6000, 3000, 2100, and 1800 MW. During this time, no treatment or penalty costs were imposed on emissions from HEP. The system's entire expenses came to \$2.4580 10^{10} dollars, and the EENS was 2.9172 10^4 MWh.

The overall capacity added to the system for the 6-year period, during which treatment/penalty fees were levied on HEP emissions, was 9400 MW, with LNG, coal and nuclear (PWR), nuclear (PHWR), and solar plants having added capacities of 2700, 3000, 2000, 700, and 1000 MW, respectively. The EENS was 3.4157104 MWh, and the entire system expenses were \$1.52831010.

The overall capacity added to the system for the 14-year period, when treatment/penalty fees were levied on HEP emissions, was 15,800 MW, with LNG, coal, nuclear (PWR), nuclear (PHWR), and solar plants having respective new capacities of 2700, 4000, 3500, and 1600 MW. The EENS was 3.9124104 MWh, and the entire system expenses were \$2.46131010.

5.7 Case 3b: 10–20% RES Penetration/SPWS Replacing Oil Plants

The total capacity added to the system for the 6-year period was 8000 MW, with LNG, coal, nuclear (PWR), nuclear (PHWR), and solar plants having respective increased capabilities of 1800, 3000, 1000, 1400, and 800 MW. The system's total expenses came to \$1.5131 10^{10} dollars, and the EENS was 3.2424 10^{4} MWh.

The total capacity added to the system for the 14-year period was 15,250 MW, with LNG, coal, nuclear (PWR), nuclear (PHWR), and solar plants having respective added capacities of 2250, 3500, 4000, 3500, and 2000 MW. During this time, no treatment or penalty costs were imposed on emissions from HEP. The EENS was 0.3294104 MWh, and the entire system expenses were \$2.48681010.

When treatment/penalty charges were applied to HEP emissions during a 6-year period, a total of 8000 MW of new system capacity was added, with additions to LNG, coal, nuclear (PWR), nuclear (PHWR), and solar plants totaling 1800 MW, 3000 MW, 1000 MW, 1400 MW, and 800 MW, respectively. The EENS was 3.2424104 MWh, and the entire system expenses were \$1.53701010.

The total capacity added to the system for the 14-year period, during which treatment/penalty fees were imposed on HEP emissions, was 14,050 MW, with LNG, coal, nuclear (PWR), nuclear (PHWR), and solar plants adding, respectively, 2250 MW, 3500 MW, 2000 MW, 4900 MW, and 1400 MW. The EENS was 2.5246104 MWh, and the total system cost was \$2.50171010.

5.8 Case 4a: 5–10% RES Penetration/SPWNS as Alternative Investment Candidate

The total capacity added to the system for the 6-year period was 9050 MW, with added capacities for solar, oil, LNG, coal, nuclear (PWR), and nuclear (PHWR) plants totaling 1600, 2250, 1500, 2000, 700, and 1000 MW, respectively. The total cost of the system was \$1.5208 10^{10} dollars, and the EENS was 2.1755 10^{4} MWh.

The total capacity added to the system for the 14-year period was 16,150 MW, with added capacities for solar, oil, LNG, coal, nuclear (PWR), and nuclear (PHWR) plants of 2400, 3150, 3500, and 3000 MW, respectively. During this time, no treatment or penalty costs were imposed on HEP emissions. The total cost of the system was \$2.6263 10^{10} and the EENS was 2.0032×10^{4} MWh.

The overall capacity added to the system for the 6-year period was 9000 MW, with increased capacities for solar, oil, LNG, coal, nuclear (PWR), and nuclear (PHWR) plants being, respectively, 400, 2700, 2500, 1000, 1400, and 1000 MW. The total cost of the system was $\$1.6139 \times 10^{10}$, and the EENS was 3.2323×10^{4} MWh.

The overall capacity added to the system for the 14-year period, when treatment/penalty fees were imposed on emissions from HEP, was 15,900 MW, with new capacities of 1800, 1800, 3500, 4000, 2800, and 2000 MW for solar, nuclear (PWR), coal, LNG, and oil plants, respectively. The total cost of the system was \$2.6537 10, and the EENS was 3.9875×10^4 MWh.

5.9 Case 4b: 5–10% RES Penetration/SPWS as Alternative Investment Candidate

The total capacity added to the system for the 6-year period was 8700 MW, with increased capacities for solar, oil, LNG, coal, nuclear (PWR), and nuclear (PHWR) plants of 2000, 1800, 1500, 1000, and 1400 MW, respectively. In total, the system cost \$1.7130 10^{10} dollars, and the EENS was 3.1173 10^4 megawatt hours.

The total capacity added to the system throughout the 14-year period was 14,550 MW, with increased capacities from oil, LNG, coal, nuclear (PWR), nuclear (PHWR), solar, and other plants totaling 1400, 2250, 4000, 1000, 4900, and 1000 MW, respectively. The total cost of the system was \$2.7653 10^{10} and the EENS was 3.7616×10^4 MWh.

The overall capacity added to the system for the 6-year period, when treatment/penalty fees were levied on HEP emissions, was 8750 MW, with increased capacities for solar, oil, LNG, coal, nuclear (PWR), and nuclear (PHWR) plants of 1600, 2250, 1500, and 1000 MW, respectively. The EENS was 2.7174104 MWh, and the entire system expenses were \$1.71561010.

The total capacity added to the system throughout a 14-year period when treatment/penalty fees were levied on HEP emissions was 14,450 MW, with capacities added by oil, LNG, coal, nuclear (PWR), nuclear (PHWR), and solar plants of 1800, 2250, 4500, 0, 4900, and 1000 MW, respectively. The system's total cost was \$2.7654 10^{10}, and the EENS was 3.5604×10^4 MWh.

5.10 Case 5a: 10–20% RES Penetration/SPWNS as Alternative Investment Candidate

The total capacity added to the system for the 6-year period was 9950 MW, with increased capacities for oil, LNG, coal, nuclear (PWR), nuclear (PHWR), and solar plants totaling 1400, 1350, 2500, 2000, 700, and 2000 MW, respectively. The EENS was $3.4713 \cdot 10^4$ MWh, while the entire system expenses were \$1.8296 10^{10} in total.

The total capacity added to the system throughout the 14-year period was 16,750 MW, with increased capacities from oil, LNG, coal, nuclear (PWR), nuclear (PHWR), and solar plants totaling 2,200, 2,250, 4,500, 2000, 2800, and 3000 MW, respectively. The total cost of the system was \$2.9877 10^{10} and the EENS was 3.3206×10^4 MWh.

The overall capacity added to the system for the 6-year period, when treatment/penalty fees were imposed on HEP emissions, was 10,050 MW, with increased capacities for solar, oil, LNG, coal, nuclear (PWR), and nuclear (PHWR) plants of 200, 3150, 2000, and 700 and 2000 MW, respectively. The system's total expenses came to \$1.9339 10^{10} dollars, and its EENS was 3.6022 10^4 MWh.

The overall capacity added to the system for the 14-year period, when treatment/penalty fees were placed on emissions from HEP, was 17,050 MW, with increased capacities for solar, LNG, coal, nuclear (PWR), and nuclear (PHWR) plants of 4000, 2250, 2000, 3000, and 2800 MW, respectively. The whole system cost was \$3.0641 per 10 square feet and the EENS was 1.6852×10^4 MWh.

5.11 Case 5b: 10–20% RES Penetration/SPWS as Alternative Investment Candidate

The overall capacity added to the system for the 6-year period was 9950 MW, with added capacities of 2000, 1350, 1500, 2000, 2000, and 2000 MW for solar, oil, LNG, coal, nuclear (PWR), nuclear (PHWR), and nuclear plants, respectively. The system's entire expenses came to \$2.2248 10^{10} dollars, and the EENS was 3.4951 10^4 MWh.

During the 14-year period, when no costs for treatment or penalties were imposed on HEP emissions, a total of 17,400 MW of system capacity was added, with added capacities for solar, oil, LNG, coal, nuclear (PWR), and nuclear (PHWR) plants of 1400, 2700, 3500, 4000, and 2800 MW, respectively. Costs for the system were \$3.20261010 and the EENS was 0.5760×10^4 MWh.

The overall capacity added to the system for the 6-year period when treatment/penalty fees were levied on HEP emissions was 9700 MW, with increased capacities for solar, oil, LNG, coal, nuclear (PWR), and nuclear (PHWR) plants of 1200, 1800, 2000, 700, and 2000 MW, respectively. The EENS was 2.9569104 MWh, and the entire system expenses were \$2.22861010.

The overall capacity added to the system for the 14-year period, when treatment/penalty fees were placed on emissions from HEP, was 17,200 MW, with increased capacities for solar, oil, LNG, coal, nuclear (PWR), and nuclear (PHWR) plants of 1400, 900, 4000, 3000, and 4900 MW, respectively. Costs for the system were \$3.2308 10^{10} and the EENS was 0.6598×10^4 MWh.

In all scenarios where the solar plants had their own storage capacity, the capacity contributed to the system and EENS were, on average, lower than for cases where there was no storage capacity. However, when storage capacity for incoming solar plants was included, the overall prices increased in all situations. This held true for planning horizons of both 6 and 14 years.

5.12 Level 1 Study: GEP Without Solar Plants (Policy Case 1) (Tables 5, 6, 7 and 8)

The overall electricity capacity increased during the 6-year period was 7850 MW, and for the 14-year planning period, it was 13,850 MW, when no treatment or penalty fees were imposed on emissions from the HEP. Like this, the overall expenses and EENS and horizons were $1.20091010 and 2.7165104 MWh for a period of 6 years and $2.18111010 and 3.8012104 MWh for a duration of 14 years.

The overall electricity capacity increased for the 6-year period was 7850 MW, and for the 14-year planning period, it was 14,000 MW, when treatment/penalty fees were placed on emissions from the HEP. The overall expenses for the 6-year and 14-year timeframes, respectively, were $1.2947,10,10 and $2.26,10,10, whereas the EENS were 2.7165,10,4 MWh and 3.6376,10,4 MWh.

5.13 Level 2 Study: GEP Based on the Introduction of Solar Plants as an Alternative Investment Candidate or as an Oil Plant Replacement (Table 5)

In Table 4.2 for the 6-year planning horizon, the thorough analysis of GEP based on the introduction of solar plants as a replacement for oil plants or as an alternative investment option is offered.

5.14 Overall Costs and Capacity Additions

When solar power plants, with or without storage, were evaluated as potential candidates for alternative investments, the system's capacity additions were consistently higher than when they were thought of as oil plant replacements. Whether or not the treatment/penalty charges were imposed on emissions from HEP plants, this qualification is still applicable to both scenarios. This means that the additional investment capacity for policy cases 2a and 3a were 8200 and 8950 MW, respectively, as opposed to policy cases 4a and 5a, which had additional investment capacities of 9050 and 9950 MW, respectively. Cases 2b and 3b as well as Cases 4b and 5b can be compared using the same criteria. When compared, the overall system costs also followed the pattern of capacity additions for the relevant situations.

5.15 EENS

However, as shown in Table 5, there were some mixed results in the EENS comparison between those patients.

5.15.1 When HEP Emissions Were not Subject to Any Costs

The EENS was lower when solar was added to the system as an alternative candidate plant rather than as a replacement for the oil plant, both for the scenarios of solar additions SPWNS and SPWS, for the estimated solar penetration level of 5–10%. To put it another way, it was less for policy cases 4a (2.1755 10^4 MWh) and 4b (3.1173 10^4 MWh) than for cases 2a (3.4770 10^{10} MWh) and 2b (3.4435 10^4 MWh); for the assumed solar penetration level of 10–20%, both for the cases of solar addition SPWNS or SPWS, the EENS is higher for the case when solar was added to the system as an alternative candidate. This means that it was more for cases 5a (3.4713 MWh) and 5b (3.4951 MWh) than for cases 3a (3.3015 MWh) and 3b (3.2424 MWh).

5.15.2 When HEP Emission Costs for Treatment and Penalties Were Imposed (Table 6)

When incoming solar plants were considered as a replacement for existing oil plants, EENS values were higher than when they were considered as an alternative capacity option when the solar plant had its own storage capacity, and they were higher when they were considered as an alternative investment candidate than when they were considered as a replacement for existing oil plants when the incoming solar plants had no storage capacity of their own.

In other words, the EENS values for policy cases 4b (2.7174 MWh) and 5b (2.9569 MWh) were lower than those for cases 2b (2.8275 MWh) and 3b (3.2424 MWh), whereas the EENS values for cases 4a (3.2323 MWh) and 5a (3.6022 MWh) were higher than those for cases 2a (2.9273 MWh) and 3a (3.4157 MWh).

5.15.3 Level 3 Study: According to Whether Solar Plants Had the Storage Capacity

The analysis focuses on GEP with costs for emissions from HEP as shown in Tables 5 and 6 and GEP with no treatment/penalty costs imposed on emissions from HEP.

GEP When No Costs Were Imposed for Treatment or Penalties for Emissions from HEP

For cases 2a and 3a, with SPWNS and the strategy for replacing the oil plants with solar, the total capacity additions increased from 8200 to 8950 MW, the total costs increased from \$1.2627 10^{10} to \$1.4702 10^{10}, and the EENS had decreased from 3.4470 10^{4} MWh to 3.3015 10^{4} MWh when the permitted solar additions to the system were increased from 5–10 to 10–20%.

When the permissible solar additions to the system were increased from 5–10 to 10–20% for cases 2b and 3b with SPWS and the strategy for SPWS replacing the oil plants, the additional capacity brought into the system for cases 2b and 3b was less than for cases 2a and 3a. The capacity added to the system between cases 2b and 3b fell from 8150 MW (for 2b) to 8000 MW (for 3b). Along with the overall capacity added, the EENS for examples 2a, 2b, 3a, and 3b followed the same pattern.

When the solar additions to the system had a storage capacity of their own, the overall system costs were higher than when the solar additions had no storage capacity. In other words, cases 2b (\$1.2812 10^{10}) and 3b (\$1.5131 10^{10}) had greater total system costs than cases 2a (\$1.2627 10^{10}) and 3a (\$1.4702 10^{10}).

GEP with Costs for HEP Emissions (Tables 5 and 6)

Solar plants were unable to store energy when penalty prices for HEP plant emissions were applied, but in identical situations where no such emission costs were considered, additional capacities were routinely added to the system. The situation was the exact opposite when solar power facilities had their own storing capability. In examples, 2a and 3a, the corresponding capabilities added to the system were 8200 and 8950 MW when no emission costs were considered, and 8750 and 9400 MW in cases when HEP emissions were subject to treatment or penalty fees.

But in cases, 2b and 3b, where the new solar power plants had storage capabilities, the system's capacity additions were 8150 and 8000 MW, respectively, when no treatment or penalty costs were imposed on HEP emissions, and the same amounts were 8000 and 8000 MW, respectively, when such costs were imposed. When treatment/penalty charges were levied on HEP emissions, the overall system costs were always greater. Regardless of the expenses associated with emissions, the EENS had a distinct pattern based on solar system additions. When penalty charges were imposed on emissions from HEP plants, the EENS had lower values when the solar penetration was expected to be between 5 and 10%. The situation changed when the assumed solar penetrations rose from 5–10 to 10–20%.

Sensitivity Research on the Effects of FOR on GEP at Level 4 (Tables 10, 11, and 12)

The literature assumed an outage ratio ranging from 6 to 76% for both a solar plant with storage and a solar plant without storage (SPWNS and SPWS). Researchers employed a mix of these values in their investigation. Sensitivity analysis was performed to examine the effects of various combinations of Forced Outage Rate (FOR) for SPWNS and SPWS, as shown in Table 9, to provide a realistic representation of the system performance.

Tables 10, 11, and 12 present the study's findings for various FOR% value combinations for both the 6- and 14-year planning horizons. For various combinations of policy instances, the variations in system capacity addition, overall costs, and EENS are also provided.

Table 9 Details of FOR% for SPWNS and SPWS

Cases	For (%)		Reference (%)
	SPWNS	SPWS	
1	76	76	76/76
2	76	6	76/6
3	6	6	6/6

Given a policy case, the incremental investment capacity was consistently larger when the FOR% combination assumed was 76/76% for SPWNS/SPWS than for the FOR% combinations of 76/6 and 6/6% for SPWNS/SPWS. When we viewed solar as an alternative investment candidate plant rather than as a substitute for oil plants, the additions of solar to the system were consistently greater for all policy situations, for all combinations of FOR%. For the circumstances when solar storage was assumed, the total capacity of plants added to the system during planning was either equal to or lower than for the cases where no sun storage was assumed.

Cases When HEP Emissions Were not Subject to Treatment or Penalty Costs

The no treatment or penalty costs were imposed on emissions from HEP including overall costs, capacity additions and EENS.

- *Overall Costs*

Depending on the cap on solar installations, overall prices between FOR% combination of 76/6 and 6/6% for SPWNS/SPWS decreased from 2.63 to 18.94% for the various policy instances. Similar comparisons can be made between the situations of FOR% for SPWNS/SPWS of 76/76 and 6/6%.

- *Capacity Additions*

When the FOR% combination for SPWNS/SPWS was changed from 76/6 to 6/6% and when it was changed from 76/76% combo to 6/6% combination, capacity increases varied similarly. The system's capacity was enhanced to accommodate combinations with higher FOR%.

- *EENS*

When solar additions were introduced as a capacity investment alternative, the comparison of EENS typically followed a similar pattern to that of overall costs and capacity additions.

Table 10 Variations in capacity added based on FOR% pairings of 76/76, 76/6, and 6/6% for planning horizons of 6 and 14 years

Policy	6 Years planning period						14 Year planning period					
	Without emission costs			With emission costs			Without emission costs			With emission costs		
	Overall cost ×10$						Overall cost ×10$					
	FOR 76/ 76%	FOR 76/ 6%	FOR 6/ 6%	FOR 76/ 76%	FOR 76/ 6%	FOR 6/ 6%	FOR 76/ 76%	FOR 76/ 6%	FOR 6/ 6%	FOR 76/ 76%	FOR 76/ 6%	FOR 6/ 6%
Case 1	1.2009	1.2009	1.2009	1.2947	1.2947	1.2947	2.1811	2.1811	2.1811	2.2627	2.2627	2.2627
Case 2a	1.2725	1.2627	1.1960	1.2974	1.2947	1.2336	2.3212	2.3011	2.1847	2.3936	2.3156	2.2474
Case 2b	1.3156	1.2812	1.2391	1.3187	1.3187	1.2791	2.4276	2.3503	2.2704	2.4968	2.3603	2.3781
Case 3a	1.4854	1.4702	1.2956	1.5283	1.5283	1.3358	2.5603	2.458	2.2888	2.660 6	2.4613	2.3679
Case 3b	1.6960	1.5131	1.4743	1.5370	1.5370	1.5204	2.1350	2.4868	2.4025	2.7879	2.5017	2.4899
Case 4a	1.4909	1.5208	1.3762	1.6139	1.6139	1.4179	2.5527	2.6263	2.3396	2.6814	2.6537	2.4283
Case 4b	1.7176	1.7130	1.6061	1.7156	1.7156	1.6462	2.7619	2.7653	2.5856	2.8835	2.7654	2.6521
Case 5a	1.7882	1.8296	1.5406	1.9339	1.9339	1.5851	2.8954	2.9877	2.4762	3.0031	3.0641	2.5543
Case 5b	2.2311	2.22248	1.8705	2.2286	2.2286	20,002	3.2259	3.2026	2.7580	3.3147	3.2308	2.8849

Table 11 Variations in total costs depending on FOR% combinations of 76/76, 76/6, and 6/6 for planning horizons of 6 and 14 years

Policy	6 Years planning period						14 Year planning period					
	Without emission costs			With emission costs			Without emission costs			With emission costs		
	Overall cost ×10$						Overall cost ×10$					
	FOR 76/ 76%	FOR 76/ 6%	FOR 6/ 6%	FOR 76/ 76%	FOR 76/ 6%	FOR 6/ 6%	FOR 76/ 76%	FOR 76/ 6%	FOR 6/ 6%	FOR 76/ 76%	FOR 76/ 6%	FOR 6/ 6%
Case 1	1.2009	1.2009	1.2009	1.2947	1.2947	1.2947	2.1811	2.1811	2.1811	2.2627	2.2627	2.2627
Case 2a	1.2725	1.2627	1.1960	1.2974	1.2947	1.2336	2.3212	2.3011	2.1847	2.3936	2.3156	2.2474
Case 2b	1.3156	1.2812	1.2391	1.3187	1.3187	1.2791	2.4276	2.3503	2.2704	2.4968	2.3603	2.3781
Case 3a	1.4854	1.4702	1.2956	1.5283	1.5283	1.3358	2.5603	2.458	2.2888	2.660 6	2.4613	2.3679
Case 3b	1.6960	1.5131	1.4743	1.5370	1.5370	1.5204	2.1350	2.4868	2.4025	2.7879	2.5017	2.4899
Case 4a	1.4909	1.5208	1.3762	1.6139	1.6139	1.4179	2.5527	2.6263	2.3396	2.6814	2.6537	2.4283
Case 4b	1.7176	1.7130	1.6061	1.7156	1.7156	1.6462	2.7619	2.7653	2.5856	2.8835	2.7654	2.6521
Case 5a	1.7882	1.8296	1.5406	1.9339	1.9339	1.5851	2.8954	2.9877	2.4762	3.0031	3.0641	2.5543
Case 5b	2.2311	2.22248	1.8705	2.2286	2.2286	20,002	3.2259	3.2026	2.7580	3.3147	3.2308	2.8849

Table 12 variations between the 76/76%, 76/6%, and 6/6% FOR% combinations using EENS for the 6-year and 14-year planning horizons

Policy	6 Years planning period						14 Year planning period					
	Without emission costs			Without emission costs			Without emission costs			Without emission costs		
	Overall cost $\times 10\$$						Overall cost $\times 10\$$					
	FOR 76/ 76%	FOR 76/ 6%	FOR 6/ 6%	FOR 76/ 76%	FOR 76/ 6%	FOR 6/ 6%	FOR 76/ 76%	FOR 76/ 6%	FOR 6/ 6%	FOR 76/ 76%	FOR 76/ 6%	FOR 6/ 6%
Case 1	2.7165	2.7165	2.7165	2.7165	2.7165	2.7165	3.8012	3.8012	3.8012	3.8012	3.8012	3.8012
Case 2a	3.7952	3.4770	2.7944	3.7952	2.9273	3.6464	2.8681	0.4211	4.0023	1.7224	2.5915	3.7182
Case 2b	2.9273	3.4435	2.7944	3.7952	2.8275	2.8607	2.7205	3.1486	3.1618	2.1669	2.0383	4.1675
Case 3a	3.4157	3.3015	2.1399	3.4157	3.4157	3.9519	1.0966	2.9172	3.4819	3.2904	3.9124	2.5003
Case 3b	3.4157	3.2424	3.2058	3.4157	3.2424	2.4079	2.1825	0.3294	2.5223	2.8326	2.5246	0.5172
Case 4a	3.2846	2.1755	3.217	0.6499	3.2326	3.1215	3.6649	2.0032	3.826	3.5226	3.9875	4.1608
Case 4b	3.2846	3.1173	4.5336	3.0745	2.7174	2.2339	2.7393	3.7616	3.6785	3.0922	3.5604	3.5879
Case 5a	2.7325	3.4713	2.9751	2.8284	3.6022	3.603	2.9424	3.3206	3.9512	2.8673	1.6852	3.4473
Case 5b	3.3586	3.4951	3.1631	2.8583	2.9569	2.1706	1.7414	0.576	2.4234	0.5238	0.6598	2.9476

For Cases Where Treatment Costs or Penalty Costs Were Imposed on HEP Emissions

Costs for capacity expansions, overall fees, and EENS were all included in the treatment or penalty costs imposed on HEP emissions.

- *Overall Costs*

Depending on the cap on solar additions and the capacity of solar plants for storage, the overall costs between FOR% combination of 76/6 and 6/6% for SPWNS/SPWS have decreased from 1.09 to 22%. Similar comparisons can be made for situations with FOR%s of 76/76 and 6/6% for SPWNS/SPWS.

- *Capacity Additions*

When the FOR% combination for SPWNS/SPWS was adjusted from 76/6 to 6/6% and from 76/76% combo to 6/6% combination, capacity additions showed comparable variances. The system's capacity was expanded to accommodate combinations with higher FOR%.

- *EENS*

When the solar plants had storage capacity, the ENS was higher than when no storage was anticipated, ranging from FOR% combinations of 6/6 to 76/6%.

Depending on whether the Emission Costs for HEP were included or not, all the aforementioned policies were taken into account for two alternative scenarios.

6 Conclusions

The thesis focuses on applying single-objective optimization to solve a GEP problem. For planning horizons of 6 and 14 years, the effects of including solar and wind power plants are examined. The effects of switching from expensive conventional oil plants to renewable solar and wind energy facilities are attempted to be studied. Using a test case and the effect analysis of many essential aspects, the system identification, model formulation, and model solutions for the GEP problem with future solar and wind additions are standardized. This is done as policy choices in the system planning are carried out. To make the system more realistic in this study, several degrees of solar plants are added into the system as a capacity option. The system analysis also takes ETPC and TERC into account.

There is also a comparison of the scenarios with and without solar power plants. The range of policy concerns considered paints a clearer picture of how solar technologies added to the system may affect the generating mix, as subject to TERC or ETPC, or both. The appropriate depiction of the variables under discussion enables the planners to examine the influence of various policy actions. Additionally, they would be able to determine the effects of integrating any given technology type plant and receive detailed information on the additional base load capabilities that will be needed when RET plants are added to the system.

Operation choices on shorter timescales must take dispatch characteristics into account to realize the true system scale benefits. Such a study would follow naturally from the one we conducted. Along with the choices on the planning of the generating mix, this would provide a deeper understanding of how the system functions. Professionals engaged in the system's long-term generation growth planning might benefit from such a study.

The study's evaluation of the effects of various FOR% combinations for SPWNS and SPWS plants on system performance and planning is another crucial component. The differential FOR% combinations employed for SPWNS and SPWS have a significant impact on the system performance and, consequently, the formulation of policy. This study, which aims to demonstrate the complexity of the decision-making process when adding solar power to an existing system, offers a four-level hierarchy to help planners grasp the full range of potential GEP policy concerns and take the appropriate course of action.

Appendix

Data for generation expansion planning study (Tables 13, 14, 15, 16 and 17).

Table 13 Forecasted peak demand [50]

Stage (year)	0 (2016)	1 (2018)	2 (2012)	3 (2022)	4 (2024)	5 (2026)	6 (2028)
Peak (MW)	5000	7000	9000	10,000	12,000	13,000	14,000
Stage (year)	0 (2016)	7 (2030)	8 (2032)	9 (2034)	10 (2036)	11 (2038)	12 (2040)
Peak (MW)	5000	15,000	17,000	18,000	20,000	22,000	24,000

Table 14 Technical and economic data of candidate plants [50]

Candidate type	Construction upper limit	Capacity (MW)	FOR (%)	Operating cost ($/kWh)	Fixed O&M cost ($Kw-Mon)	Capital cost ($/kW)	Life time (Years)
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

(continued)

Table 14 (continued)

Candidate type	Construction upper limit	Capacity (MW)	FOR (%)	Operating cost ($/kWh)	Fixed O&M cost ($Kw-Mon)	Capital cost ($/kW)	Life time (Years)
Nuc. (PHWR)	3	700	7.0	0.003	5.50	1750.0	25
Solar	3	1000	0.76	0.001	2.08	3873	25
Wind	3	1000	0.754	0.001	1.46	1500	25

Table 15 Technical and economic data of existing plants [50]

Name (fuel type)	No. of units	Unit capacity (MW)	FOR (%) ($/kwh)	Operating cost ($/kW-Mon)	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 GC/C#3 (LNG)	2	450	11.0	0.035	2.00
Coal#1 (Anthracite)	1	250	15.0	0.023	6.65
Coal#2 (Bitouminous)	1	500	9.0	0.019	2.81
Coal#3 (Bitouminous)	1	500	8.5	0.015	2.81
Nuclear#1 (PWR)	1	1.000	9.0	0.005	4.94
Nuclear#2 (PHWR)	1	1.000	8.8	0.005	4.63

Table 16 Technical and economic data of the solar and wind power plant without energy storage [51]

Plant type	FOR (%)	Operating cost ($/kWh)	Fixed O&M cost ($/Kw-Mon)	Capital cost ($/kW)	Life time (Years)
Solar plant without energy storage	76	0.001	2.08	3873	25
Wind plant without energy storage	75.4	0.001	1.46	1500	20

Table 17 Technical and economic data of the solar plant with energy storage [49]

Plant type	FOR (%)	Operating cost ($/kWh)	Fixed O&M cost ($/Kw-Mon)	Capital cost ($/kW)	Life time (Years)	Storage/day time	Battery type
Solar plant with energy storage	6	0.0015	4.17	6530	15	6 h storage/day	Lead acid battery

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