DEVELOPMENT OF A SOLAR PV CAPACITY ADDITION PLAN FOR SRI LANKA TO MAXIMIZE ECONOMIC BENEFITS

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Degree of Master of Science

Department of Electrical Engineering

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DECLARATION

I declare that this is my own work and this thesis does not incorporate without acknowledgement any material previously submitted for a Degree or Diploma in any other University or institute of higher learning and to the best of my knowledge and belief it does not contain any material previously published or written by another person except where the acknowledgement is made in the text.

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The above candidate has carried out research for the Masters under my supervision.

Signature of the supervisor: Date:

Dr. Upuli Jayatunga

Signature of the supervisor: Date:

Dr. Tilak Siyambalapitiya

DEDICATION

I dedicate this M.Sc research thesis to my beloved parents for their guidance given throughout my life.

ACKNOWLEDGEMENT

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ABSTRACT

Sri Lanka has set various targets to integrate renewable energy-based power plants into the main grid while keeping a stronger focus on solar photovoltaic (PV) and wind power plants. A proper economic justification is not available, specially for targets set on increasing the capacity of solar PV systems.

This research addresses this drawback by quantifying the economic costs and benefits related to electricity generated by solar PV systems under penetration of different solar PV capacities. An optimum capacity which maximizes the net economic benefits was derived as the final output of the research.

Sri Lankan power system at generation level was modelled using a dispatch modelling software (PLEXOS) to obtain displaced fossil fuel and variable operation and maintenance (O&M) costs, by electricity generated by solar PV systems. A spreadsheet-based economic benefits evaluation model was used to calculate the present value of net benefits of the analysed solar PV penetration levels.

Key words: economic analysis, dispatch modelling, solar electricity, PLEXOS

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LIST OF ABBREVIATIONS

Abbreviation	Description
$	United States Dollars
^0C	degree Celsius
AC	Alternating Current
ADB	Asian Development Bank
bbl	barrel
BCR	Benefits to Costs Ratio
BoS	Balance of System
CEB	Ceylon Electricity Board
EBEM	Economic Benefits Evaluation Model
FiT	Feed in Tariff
GML	Ground Mounted Large
GWh	gigawatt hour
IAEA	International Atomic Energy Agency
IPP	Independent Power Producers
EIRR	Economic Internal Rate of Return
IRR	Internal Rate of Return
kcal	kilo calories
LDC	Load Duration Curve
LECO	Lanka Electricity Company (Private) Limited
LOLP	Loss of Load Probability
LTGEP	Long Term Generation Expansion Plan
m^2	square meter
MMBtu	Million British Thermal Units
MoPEBD	Ministry of Power, Energy and Business Development
MoPRE	Ministry of Power and Renewable Energy
MT	Metric Ton
MW	megawatt
NCRE	Non Conventional Renewable Energy
NPV	Net Present Value

Abbreviation	**Description**
NREL	National Renewable Energy Laboratory
O&M	Operation and Maintenance
ORE	Other Renewable Energy
PUCSL	Public Utilities Commission of Sri Lanka
PV	Photovoltaic
RE	Renewable Energy
SAM	System Advisory Model
SCF	Standard Conversion Factor
SERF	Shadow Exchange Rate Factor
SLSEA	Sri Lanka Sustainable Energy Authority
SPP	Small Power Producers
ST	Short Term
STC	Standard Test Condition
SWRF	Shadow Wage Rate Factor
UNDP	United Nations Development Programme
W	watt
WASP	Wien Automatic System Planning package

CHAPTER 1

INTRODUCTION

1.1 Electricity Sector in Sri Lanka

National grid of Sri Lanka serves the total electricity demand of the country except in four (4) islands in Jaffna Peninsula. Peak demand and electricity consumption in 2017 were 2,523 megawatt (MW) and 13,357 gigawatt hour (GWh) respectively [1]. Electricity consumption has shown an average annual growth of 5.95% over the period of 2013-2017. Published percentage of electrified households was 99.3% in 2016 [2].

Ceylon Electricity Board (CEB) and Lanka Electricity Company (Private) Limited (LECO) are the two power utilities in the country. CEB is engaged in separate licensed activities of generation, transmission and distribution, whereas LECO is engaged only in distribution. Public Utilities Commission of Sri Lanka (PUCSL) regulates all licensed activities of electricity sector. In addition, Sri Lanka Sustainable Energy Authority (SLSEA) is the apex body promoting and regulating Renewable Energy (RE) and energy efficiency activities in the country. CEB, LECO and SLSEA are affiliated to Ministry of Power, Energy and Business Development (MoPEBD).

Total installed electricity generation capacity on the grid, which comprises capacities of power plants which are owned by CEB, Small Power Producers (SPPs) and Independent Power Producers (IPPs) was 4,087 MW in 2017 [1]. Primary sources of electricity generation are hydropower, wind power, solar power, biomass, coal, naphtha, diesel, fuel oil and residual oil.

There were 6.75 million electricity customers in 2017 [1]. Tariff structure has divided electricity customers into seven (7) main categories. Tariff category wise number of customer percentages and electricity sales percentages in 2017 were, Domestic (87%, 37%), Religious (1%, 1%), General Purpose (11%, 25%), Hotel (negligible, 2%), Industrial (1%, 32%), Government (negligible, 1%) and Street Lighting (negligible, 1%).

1.2 Generation Mix and Renewable Energy Development

In 2017, total electricity generation was 14,671 GWh, and as depicted in Figure 1.1, respective energy share in generation were hydropower (27%), coal (35%), oil (34%) and Other Renewable Energy (ORE) (4%) [1].

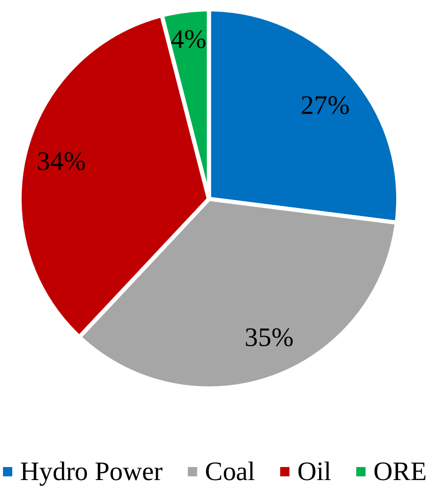

Figure 1.1: Generation Mix in 2017

Commercially operating RE power plant types and their installed capacities as of 2017 were, biomass (13 MW), dendro (11 MW) mini hydro (342 MW), and wind (128 MW) [3]. In addition, installed solar photovoltaic (PV) capacity by end of 2017 was about 130 MW. Introduction of technology specific Feed in Tariff (FiT) for Non Conventional Renewable Energy (NCRE) power plants in 2007, lifted RE development and it helped to achieve the national policy target of 10% of electricity generation from NCRE power plants by 2015. At present CEB procures large solar PV and wind power through competitive bidding.

First large solar PV power plant in Sri Lanka was commissioned in 2011. Eight (8) large solar PV power plants with cumulative capacity of 51 MW were in operation by end of 2018. A bidding round for 60×1 MW large solar PV power plants was announced in March 2017. The Net Metering scheme which was introduced in 2008 to customers to generate electricity from any RE source and feed any surplus to the national grid, enabled rooftop solar PV development in Sri Lanka. By end of 2015, 4,199 customers had installed rooftop solar PV systems with cumulative capacity of about 27 MW. In mid-2016, Ministry of Power and Renewable Energy (MoPRE) launched the "Battle for Solar" programme with the target of adding 200 MW and 1,000 MW of rooftop solar PV systems by 2020 and 2025 respectively. The programme introduced two (2) new schemes called Net Accounting and Net Plus which allow customers to sell surplus and total electricity generation to the utility respectively. In parallel, local banks introduced loan schemes with concessionary interest rates for customers to install rooftop solar PV systems. These interventions had increased the number of rooftop solar PV customers to 17,500 with a cumulative installed capacity of 150 MW by end of September 2018. Historical growth in solar PV capacity is shown in Figure 1.2.

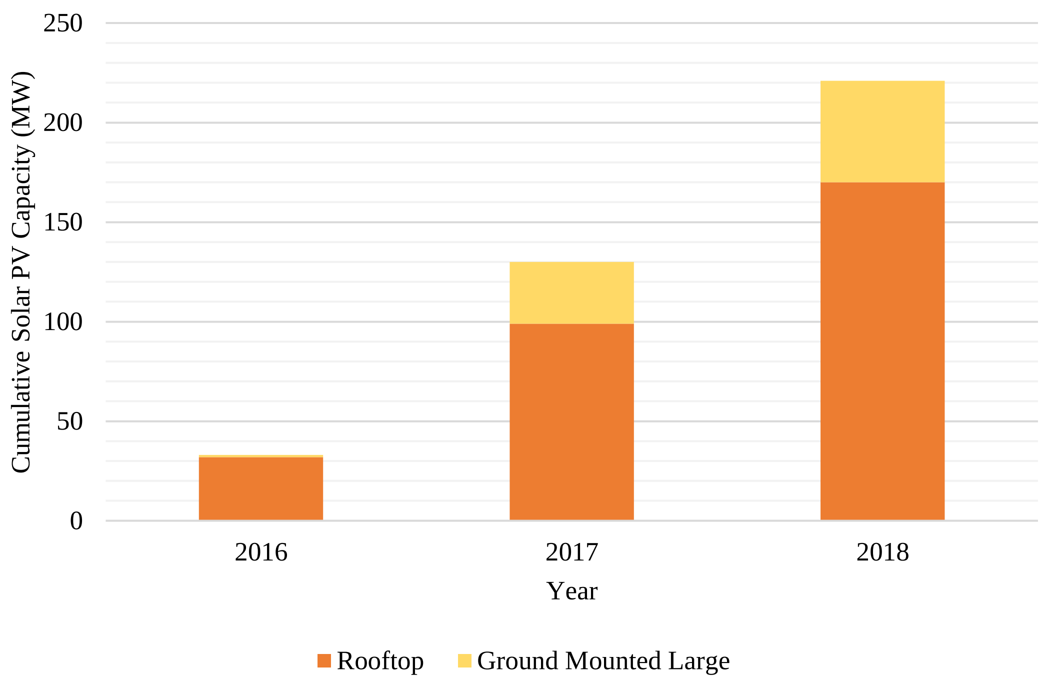

Figure 1.2: Historical Growth in Solar PV Capacity

In 2017, Asian Development Bank (ADB) in collaboration with United Nations Development Programme (UNDP) published a report which presents a target of 100% electricity generation thorough RE by 2050 for Sri Lanka. The study anticipated solar PV capacity of 392 MW and 900 MW by 2020 and 2025 respectively [4].

1.3 Research Motivation

As discussed in section 1.2, policy makers have set various policy targets related to solar PV capacity additions, and programmes have been implemented to support those targets. Formulation of a national policy should follow a systematic process which assesses the economic viability of it, followed by technical and financial viabilities. Although a policy is technically and financially viable, it should not be implemented if it is not economically viable. Economically viable policies should be further assessed to maximize net economic benefits. Formulation of policies related to solar PV development in Sri Lanka has not followed this procedure, and any related justification is not available in public domain. Filling this void and revising policy targets accordingly, will ensure that Sri Lanka is gaining maximum economic benefits through solar PV electricity generation.

1.4 Research Objectives

The objective of this research is to develop a solar PV capacity addition plan, which maximizes net economic benefits of the solar PV power development programme for the period of 2018-2037. When developing the optimal solar PV capacity addition plan, future demand growth and expansion of other types of generator capacities as per CEB Long Term Generation Expansion Plan (LTGEP) 2018-2037 [5] has been taken into account.

1.5 Research Overview

In order to achieve the research objective, identification of economic costs and benefits related to solar PV capacity addition is required. A literature review was conducted to identify related studies which had been carried out specially focusing on the Sri Lankan power system. Parameters derived through such research work were used to narrow down the scope of this research more into an economic analysis.

Existing and planned power plants as given in the base case of CEB LTGEP 2018-2037 were modelled in a dispatch analysis software. Variation of energy outputs of individual power plants and related costs under different solar PV capacities were identified using the dispatch model.

A spreadsheet based Economic Benefits Evaluation Model (EBEM) was developed to convert financial costs and benefits into the economic domain, and to select the solar PV capacity addition scenario which maximizes the economic benefits.

CHAPTER 2

LITERATURE REVIEW

2.1 Cost of Solar PV Systems

As depicted in Figure 2.1, the capital cost of solar PV systems has decreased rapidly in recent years and is expected continue to decline in the future [6].

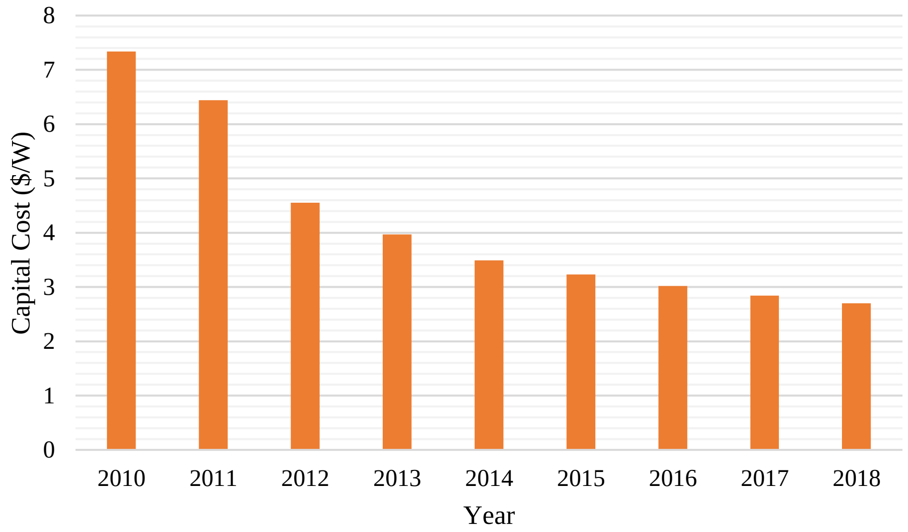

Figure 2.1: Reduction in NREL cost benchmark of rooftop solar PV systems [6]

Market maturity, business model integration, product innovation and economies of scale have been the causes for this reduction. A 40% reduction in capital cost of rooftop solar PV systems when compared with the capital costs in 2017, can be expected by 2030 [7]. Solar PV system can be categorized as: i) rooftop residential; ii) rooftop commercial; iii) fixed tilt ground mounted utility scale; and iv) ground mounted utility scale with tracking. Unit capital costs of above categories are slightly different.

Cost components of a solar PV system are PV modules, inverter, structures, electrical Balance of System (BoS), installation labor, cost of interconnection and commissioning, supply chain cost, taxes, marketing, profits and cost of land acquisition for Ground Mounted Large (GML) solar PV systems. Component wise cost breakdown of solar PV systems is depicted in Figure 2.2.

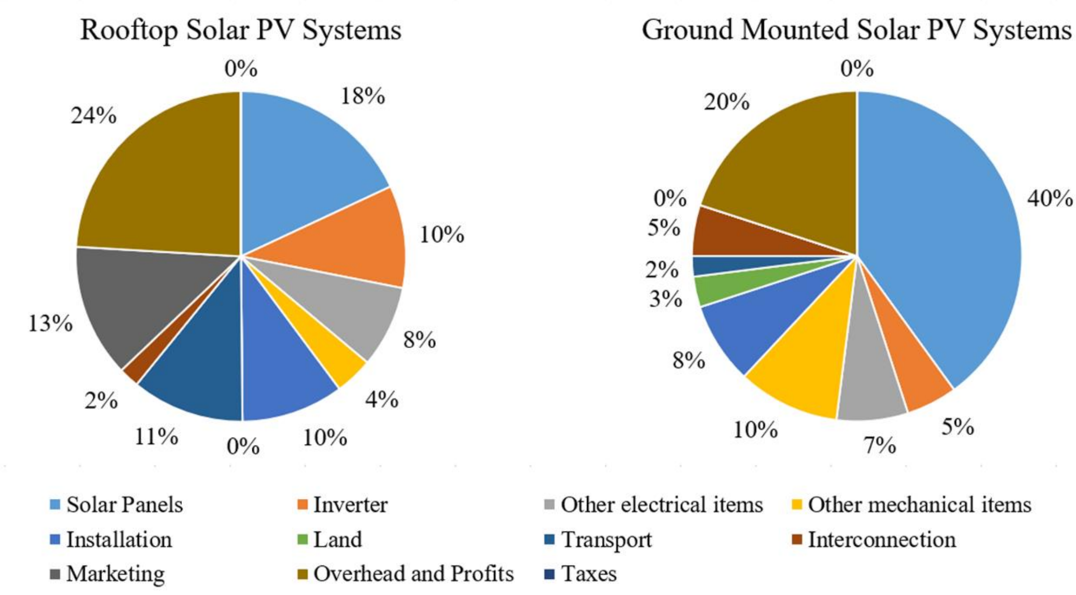

Figure 2.2: Component wise cost breakdown of solar PV systems [6]

Operation administration (only for utility scale systems), inverter replacements, module and other components replacement, system inspection and monitoring, module cleaning, and vegetation clearing are the preventive and corrective maintenance work related to solar PV systems. Fixed annual Operation and Maintenance (O&M) cost of solar PV systems depends on the system type, and is in the range of 0.5% - 1.0% of the capital cost.

2.2 Economic Cost Benefit Evaluation

Limitation of resources makes financial appraisal of projects important, because it helps investors to make decisions on investing projects. However, financial appraisal does not identify the overall costs and benefits of the project at the national level [8]. For an example, investing on rooftop solar PV systems is financially viable for high end electricity customers while it isn’t viable for low end electricity customers, and current tariff structure in Sri Lanka causes financial losses to the transmission licensee who is purchasing electricity from rooftop solar PV systems. However, electricity generated by solar PV systems displaces fossil fuel based electricity generation which is an economic benefit to the country [9]. Economic viability of solar PV systems should be further analysed considering economic costs which reflect values of goods and services on the national economy. Projects which are economically and financially viable can be developed by private sector investors, while projects which are economically viable but not financially viable, require government intervention to sustain.

Project economic analysis ensures that the investment brings benefits to the country. There are four (4) steps in project economic analysis: i) identify gross project benefits and costs; ii) quantify and value the benefits and costs, initially in financial prices; iii) adjust the costs and benefits to reflect their economic values; and (iv) compare gross economic benefits with economic costs [10]. Benefits can be further categorized as incremental and non-incremental. Sri Lanka has achieved a 99.3% electrification rate by 2016 [2] and therefore, electricity supplied by solar PV systems can be identified as a non-incremental benefit which replaces another form of resource required for electricity generation. In an economic analysis, financial costs should be categorized as: i) traded goods; ii) non traded goods; iii) labour iv) land and natural resources and v) transfers. Different conversion factors should be used for above categories to convert financial costs into economic costs, which is called "shadow pricing".

The difference between annual economic costs and benefits provides the annual net economic benefits. Economic Internal Rate of Return (EIRR) or present value of net benefits which are calculated considering net economic benefits throughout the full lifetime of the project can be used as decision making tools to select a project or to decide on the scale of a project. Variations in project scale affects both costs and benefits, and subsequently on present value of net benefits. By gradually changing the project scale, present value of net benefits maximizing project scale can be identified.

2.3 Reserve Requirement

Operating reserves are maintained by power system operators to maintain the system stability, which can be disturbed due to demand supply unbalances. Operating reserves can be categorized based on their response speed, duration, the direction of use, frequency of use and the purpose of use.

Regulating and contingency reserves are maintained by power system operators to control the frequency within the national standards. Regulating reserves are used to correct the small and slow changes such as small variations in load or variations in electricity supply by generators that use intermittent resources, while contingency services are used to manage large and fast events such as a generator tripping or a rejection of a large load. Maintaining an adequate amount of regulating reserves is sufficient to damp out frequency variations caused by variability of solar PV electricity generation and the load. However, variability of solar PV electricity generation is higher than the load variability and therefore, regulating reserve requirement is increased with the increase of installed solar PV capacity [11].

In countries where power markets are being operated, different types of reserve provisions have been identified as ancillary services which are purchased by both bidding generators and loads [12].

2.4 Technical Issues of Solar PV Systems at Distribution Level

Increased penetration of rooftop solar PV systems causes issues at distribution networks such as voltage rise, voltage unbalance and increased harmonic levels [13], [14]. The threshold solar PV capacity which can be managed with existing assets without violating the operating criteria, varies with the demand pattern and the technical parameters of the given network. For example, an urban distribution network with high day-time demand and feeders with short lengths can absorb higher solar PV capacity than a rural distribution network.

Feeder wise studies should be conducted to identify this threshold level which is defined as the "Hosting Capacity" [15], [16], [17] .

Network modifications such as installing On Load Tap Changers in distribution transformers, increasing conductor diameter, installing battery storage either at customer premises or at distribution network and use of smart inverters are required to absorb a given solar PV capacity, without violating the distribution network operating criteria [18].

2.5 Available Software Tools

CEB uses Wien Automatic System Planning package (WASP) which was developed by International Atomic Energy Agency (IAEA) to conduct long term generation planning studies [5]. WASP can optimize the generation expansion plan while considering constraints such as demand, allowed Loss of Load Probability (LOLP), limitations on emissions, and energy constraints of hydro power plants [5]. However, WASP does not provide sufficient tools to model generators with daily and seasonally varying available capacities. CEB considers power output of solar PV systems as a negative load and deduct from the annual load curve before generating Load Duration Curves (LDCs) which are inputs to WASP.

PLEXOS® energy simulating software which was developed by Energy Exemplar provides tools for long term generation expansion planning, medium term outage optimization and short term dispatch scheduling. Flexibility of the software allows the user to model complex problems such as reserve requirement with very high level of accuracy. Possibility of using chronological demand profiles for short term dispatch scheduling, and modelling solar PV and other daily capacity varying generators using chronological capacity profiles; allow power system operators to study the impacts of integrating such generators to the grid. An academic license for PLEXOS can be requested for research work.

System Advisory Model (SAM) which was developed by National Renewable Energy Laboratory (NREL) is a techno-economic model that calculates performance and financial viability of RE projects [19]. SAM has a set of solar resource data developed using satellite based measurements, which are required to simulate performance of solar PV systems.

CHAPTER 3

QUANTIFICATION OF COSTS AND BENEFITS OF SOLAR PV SYSTEMS

This chapter discusses the methodology followed to quantify economic costs and benefits of solar PV systems.

3.1 An Overview of the Methodology

In order to achieve the objective of this research, a methodology was developed to quantify economic costs and benefits related to solar PV capacity additions. The methodology as shown in Figure 3.1 can be divided into three (3) main phases which are: i) defining solar PV capacity additions in a logical manner; ii) quantification of economic benefits of different levels of solar PV capacity additions; and iii) selection of solar PV capacity addition level which maximizes the net economic benefits. A dispatch model and an economic benefits evaluation model were used in phase ii and iii respectively.

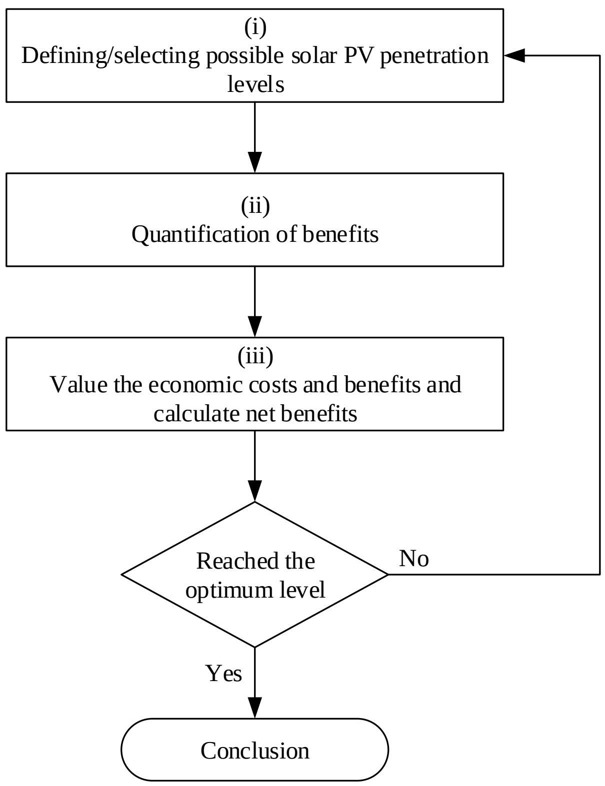

Figure 3.1: Overview of the research methodology

3.2 Analysed Solar PV Capacity Additions

In an optimization problem, all theoretically possible solutions should be considered. However, the problem can be simplified by filtering out impractical solutions. A large number of solar PV capacity addition plans can be generated by varying annual solar PV capacity additions. In this research, analysis was limited to eight (8) solar PV penetration levels.

3.2.1 Solar PV Penetration Level

The term "Solar PV Penetration Level" was used in this research to define the solar PV capacity additions beyond 2025. Solar PV penetration level can be defined in several forms. In this research, it was defined as the percentage ratio between the cumulative installed solar PV capacity [Alternating Current (AC) capacity of inverters] and the annual day peak demand, as given in (1).

$$\text{Solar PV Penetration Level} = \frac{\text{Cumillative Installed Solar PV AC Capactiy}}{\text{Annual Day Peak Demand}} \times 100\% \text{ - (1)}$$

Solar PV panels are rated at Standard Test Conditions (STCs) which are listed below.

- Solar irradiance level - 1,000 W/m^2
- Cell operating temperature – 25 ^{0}C
- Mass of the air – 1.5

Normal operating conditions vary with the installed location of the solar PV system and therefore, the rated performance can not be achieved. In addition, wiring losses, soiling and inverter losses further reduce the power output. Industry practise is to oversize the panel capacity above the inverter capacity by about 20%, to match this reduction and to fully utilize the inverter capacity. For example, inverter capacity of a 100 MW solar PV system is 100 MW and the panel capacity would be 120 MW. It was assumed that all solar PV developers follow this design principle.

It was assumed that all solar PV systems planned to be commissioned in a given year is available for operation from the 1st of January of the same year.

3.2.2 Short Term Solar PV Capacity Forecast

Annual solar PV capacity additions up to 2020 were forecast based on current capacity of installed solar PV systems, committed projects and ongoing investment programmes.

CEB, LECO and SLSEA maintain records of historical installed solar PV capacities. There are slight differences among these records, and it does not affect the accuracy of this research significantly. Historical records of SLSEA which are given in Table 3.1, was used for the solar PV capacity forecast up to 2020.

Table 3.1: Historical Annual Solar PV capacity additions

Period	**Rooftop Solar PV**						**Ground Mounted Solar PV**		**Total Solar PV Capacity Addition (MW)**
	Net Metering		**Net Accounting**		**Net Plus**				
	Number of Installations	**Capacity (MW)**	**Number of Installations**	**Capacity (MW)**	**Number of Installations**	**Capacity (MW)**	**Number of Installations**	**Capacity (MW)**	
2016	6,485	32	-	-	-	-	3	1	33
2017	4,665	38	2,327	15	220	14	3	30	97
2018	1,480	18	2,210	14	193	20	2	20	72
Total	**12,630**	**88**	**4,537**	**29**	**413**	**34**	**8**	**51**	**202**

Source: Sri Lanka Sustainable Energy Authority

In 2018, CEB issued a tender to install 1×60 MW GML solar PV power systems, and about half of them which are planned to be commissioned in 2019, have obtained provisional approval from SLSEA in 2018. The remaining 30 MW will be commissioned in 2020. In addition, based on historic figures, an annual addition of 50 MW and 20 MW of rooftop and ground mounted solar PV capacity, respectively, can be expected to be operational by 2020. The forecast of annual cumulative solar PV capacities and calculated solar PV penetration levels up to 2020, based on the above figures are given in Table 3.2.

Table 3.2: Forecast Solar PV capacity up to year 2020

Year	Cumulative Solar PV Capacity (MW)	Annual Peak Day Demand (MW)	Solar PV Penetration Level
2016	33	2,106	1.5%
2017	130	2,264	5.7%
2018	220	2,396	9.2%
2019	320	2,536	12.6%
2020	420	2,683	15.7%

CEB LTGEP 2018-2037 assumes that the day peak demand will reach 4,726 MW by 2030. This requires an annual growth rate of 5.8% of the day peak demand, which was used to calculate day peak demands for years 2018, 2019 and 2020 in Table 3.2.

3.2.3 Solar PV Capacity Additions After 2020

A linear increase in cumulative solar PV capacity from 2020 to 2025 was assumed, to avoid unrealistic annual solar PV capacity additions in initial years at high solar PV penetration levels. Annual cumulative solar PV capacities related to analysed penetration levels are given in Table 3.3.

Table 3.3: Annual cumulative solar PV capacities related to analysed penetration levels

Year	Day Peak Demand (MW)	Cumulative Solar PV Capacity (MW)							
		15%	20%	25%	30%	35%	40%	45%	50%
2018	2,396	220	220	220	220	220	220	220	220
2019	2,536	320	320	320	320	320	320	320	320
2020	2,683	420	420	420	420	420	420	420	420
2021	2,840	442	478	514	549	585	620	656	692
2022	3,005	464	536	608	678	750	820	892	964
2023	3,180	486	594	702	807	915	1,020	1,128	1,236
2024	3,365	508	652	796	936	1,080	1,220	1,364	1,508
2025	3,561	534	712	890	1,068	1,246	1,424	1,602	1,780
2026	3,768	565	753	942	1,130	1,318	1,507	1,695	1,884
2027	3,988	598	797	996	1,196	1,395	1,595	1,794	1,993
2028	4,220	633	844	1,055	1,266	1,477	1,688	1,899	2,110

Year	Day Peak Demand (MW)	Cumulative Solar PV Capacity (MW)							
		15%	20%	25%	30%	35%	40%	45%	50%
2029	4,466	669	893	1,116	1,339	1,563	1,786	2,009	2,232
2030	4,726	708	945	1,181	1,417	1,654	1,890	2,126	2,363
2031	4,939	740	987	1,234	1,481	1,728	1,975	2,222	2,469
2032	5,157	773	1,031	1,289	1,547	1,804	2,062	2,320	2,578
2033	5,381	807	1,076	1,345	1,614	1,883	2,152	2,421	2,690
2034	5,612	841	1,122	1,403	1,683	1,964	2,244	2,525	2,806
2035	5,854	878	1,170	1,463	1,756	2,048	2,341	2,634	2,927
2036	6,107	916	1,221	1,526	1,832	2,137	2,442	2,748	3,053
2037	6,372	955	1,274	1,593	1,911	2,230	2,548	2,867	3,186
2038	6,642	996	1,328	1,660	1,992	2,324	2,656	2,988	3,321
2039	6,915	1,037	1,383	1,728	2,074	2,420	2,766	3,111	3,457
2040	7,193	1,078	1,438	1,798	2,157	2,517	2,877	3,236	3,596

3.3 The Dispatch Model

Increase in solar PV penetration level can cause two types of economic benefits at generation level which are: i) fossil fuel and variable O&M cost savings due to displacement of thermal electricity generation; ii) delay in capacity addition of conventional power plants due to reduction in annual energy and capacity requirement from conventional power plants. A long term generation expansion planning tool can be used to identify 2^{nd} types of benefits. However, changes in the national generation expansion plan should comply with the national energy policy, space availability to construct power plants, feasibility of expanding the transmission grid and the dynamic stability of the power system under contingencies. Development of separate generation expansion plans to identify 2^{nd} type of benefits required comprehensive analysis of all the above factors under each solar PV penetration level and therefore, 2^{nd} type of benefit was not considered in this research by assuming that the capacity additions other than solar PV in base case of CEB LTGEP 2018-2037 remains unchanged under all analysed solar PV penetration levels.

A model which can dispatch power plants to minimize the total operating cost considering medium term and short term constrains, can be used to identify 1st type of benefits. “Medium Term Schedule” and “Short Term Schedule” modules available in the PLEXOS software were used for this purpose.

Sections 3.3.1 to 3.3.4 explain the inputs used in the dispatch model.

3.3.1 Demand Profiles

Solar PV electricity generation shows a daily and seasonal variation with the varying solar irradiance and therefore, it is important to use chronological demand profiles with an acceptable resolution to study the impact of solar PV electricity generation on dispatch scheduling. CEB LTGEP 2018-2037 provides forecast annual peak demand and energy requirement at generation level excluding auxiliary consumption of power plants. According to the forecast, day peak demand matches the night peak demand in 2030. In order to achieve this, an annual 5.8% growth of the day peak demand is required. The same growth rate for day peak demand was assumed after 2030. According to the forecast, night peak demand shows an annual growth rate of 4% from 2021 to 2030. The same growth rate for night peak demand was used after 2030. Annual energy requirement, night and day peak demands and load factors are given in Table 3.4.

Table 3.4: Annual demand forecast

Year	Energy (GWh)	Night Peak Demand (MW)	Day Peak Demand (MW)	Load Factor
2018	16,188	2,738	2,396	67.5%
2019	17,285	2,903	2,536	68.0%
2020	18,456	3,077	2,683	68.5%
2021	19,370	3,208	2,840	68.9%
2022	20,331	3,346	3,005	69.4%
2023	21,342	3,491	3,180	69.8%
2024	22,404	3,643	3,365	70.2%
2025	23,522	3,804	3,561	70.6%
2026	24,697	3,972	3,768	71.0%
2027	25,933	4,149	3,988	71.4%
2028	27,225	4,335	4,220	71.7%

Year	Energy (GWh)	Night Peak Demand (MW)	Day Peak Demand (MW)	Load Factor
2029	28,570	4,527	4,466	72.0%
2030	29,990	4,726	4,726	72.4%
2031	31,328	4,915	4,939	72.8%
2032	32,962	5,112	5,157	73.6%
2033	34,099	5,316	5,381	73.2%
2034	35,546	5,529	5,612	73.4%
2035	37,063	5,750	5,854	73.6%
2036	38,642	5,980	6,107	73.8%
2037	40,302	6,219	6,372	74.0%
2038	41,992	6,642	6,468	74.1%
2039	43,699	6,915	6,728	74.2%
2040	45,431	7,193	6,996	74.1%

Thirty (30) minute interval generation profile of 2017 was prorated to match annual day and night peak demands of each year. Then, the other points of the profile were adjusted to match annual energy requirement assuming that points closer to the peak demand vary by low percentages and points with low demand vary by high percentage. Annual demand profiles in 30-minute intervals, which were generated following the above methodology were used as an input to the dispatch model. The Figure 3.2 depicts the forecast daily demand profiles of 1st of January in 2020, 2025, 2030 and 2035.

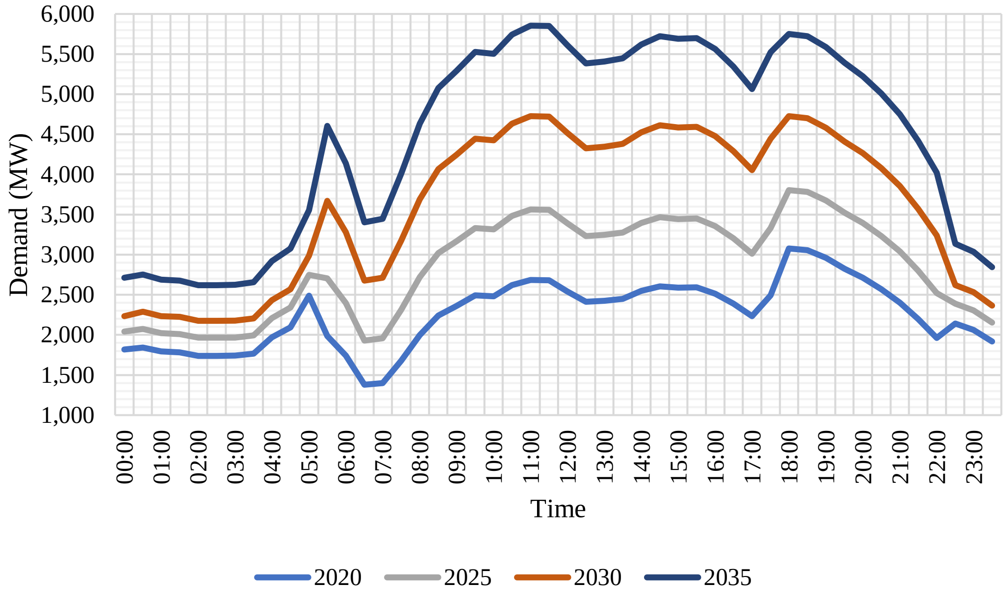

Figure 3.2: Forecast daily demand profiles

Note: Demand profile of 1st of January

3.3.2 Technical Parameters of Generators

3.3.2.1 Generator Categorization

All existing, committed and candidate generators were divided into three (3) main categories which are: i) unconstrainted; ii) energy constrained; and iii) capacity constrained, based on their characteristics as shown in Table 3.5.

Table 3.5: Generator categorization

Category	Generators
Unconstrained	All fossil fuel based thermal generators
Energy constrained	Large hydro generators
Capacity constrained	Biomass, mini hydro, solar PV and wind generators (Non dispatchable generators)

Technical parameters which were used for unconstrainted generators are given in Annex A.

3.3.2.2 Energy Constrained Generators

Limitation in available water levels at reservoirs which shows a monthly variation, categorizes large hydro generators as energy constrained generators. Expected annual energy of individual hydro generators at weighted average hydro condition, were distributed into months based on monthly total expected energy from hydro power plants as given in Table 3.6.

Table 3.6: Monthly expected energy from large hydro power plants

Power Plant	Monthly Expected Energy in Weighted Average Hydro Condition (GWh)											
	January	February	March	April	May	June	July	August	September	October	November	December
Canyon	12	8	9	9	14	15	14	13	14	19	14	20
Wimalasurendra	8	6	6	6	10	11	10	9	10	13	10	14
Old Laxapana Stage 1	11	8	8	9	13	15	14	13	13	18	13	19
Old Laxapana Stage 2	10	7	7	8	11	13	12	11	12	15	12	16
New Laxapana	40	28	29	31	47	53	49	46	49	64	48	67
Polpitiya	33	23	24	26	39	44	40	37	40	52	39	55
Upper Kotmale	30	21	22	23	35	39	37	34	36	47	35	50
Victoria	63	44	46	49	74	83	77	72	76	100	75	106
Kotmale	36	26	26	28	42	48	44	41	44	58	43	61
Randenigala	33	23	24	26	39	44	41	38	40	53	39	55
Ukuwela	11	8	8	9	13	15	14	13	14	18	13	19
Bowatenna	3	2	3	3	4	5	4	4	4	6	4	6
Rantambe	17	12	13	14	20	23	21	20	21	28	21	29
Samanalawewa	25	18	18	19	29	33	31	28	30	40	30	42
Kukule	22	15	16	17	26	29	27	25	26	35	26	37
Broadlands	9	6	7	7	11	12	11	10	11	15	11	15
Moragolla	7	5	5	6	8	9	9	8	9	11	8	12
Uma Oya	21	15	15	16	25	28	26	24	25	34	25	35
Gin Ganga	5	3	4	4	6	6	6	5	6	8	6	8
Thalpitigala	4	3	3	3	4	5	5	4	5	6	4	6
Moragahakanda	8	6	6	6	10	11	10	9	10	13	10	14
Seethawaka	3	2	3	3	4	5	4	4	4	6	4	6

3.3.2.3 Capacity Constrained Generators

All non dispatchable generators including solar PV, were modelled as capacity constrained generators. Current practice in Sri Lanka is to absorb all available capacities of these generators in a given interval into the system without considering economic dispatch principles.

For biomass generators, a plant factor of 80% was assumed and therefor, 80% of the installed capacity of biomass generators is available throughout the year.

Energy supply from mini hydro power plants exhibits a seasonal variation. CEB had conducted a study using historical energy data of mini hydro power plants, and generated an average monthly capacity factor profile which is shown in Figure 3.3. The same monthly average capacity factors were used in this research.

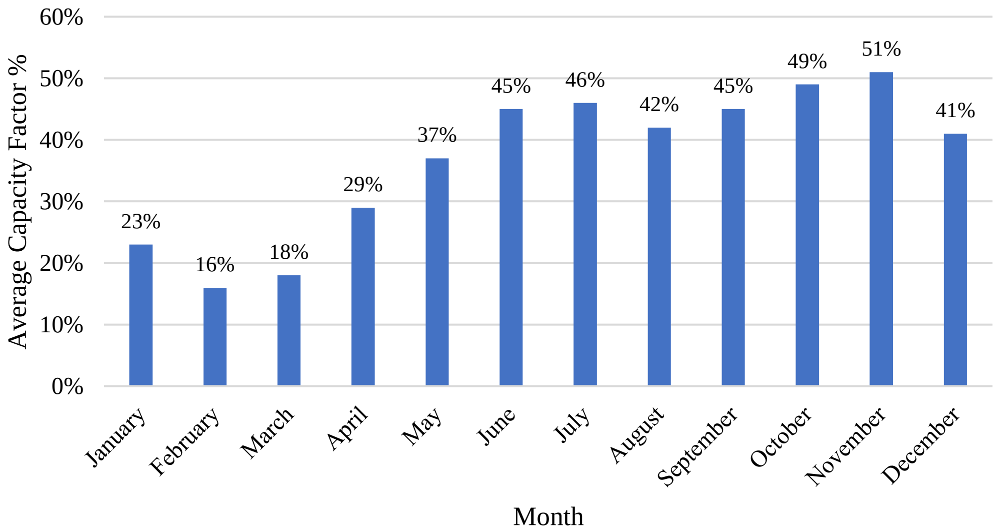

Figure 3.3: Average monthly capacity factor profile for mini hydro power plants

Source: CEB LTGEP 2018-2037

Wind power generation shows both daily and seasonal variations. Simulated chronological 30 minute interval power output profiles of committed 100 MW wind farm in Mannar was used to capture these variations. The power output profile was prorated to match with the total installed capacity of wind power plants assuming that the same plant factor and wind resource variation pattern for all wind power plants in Sri Lanka. Capacity factor profile used for wind generators is shown in Figure 3.4.

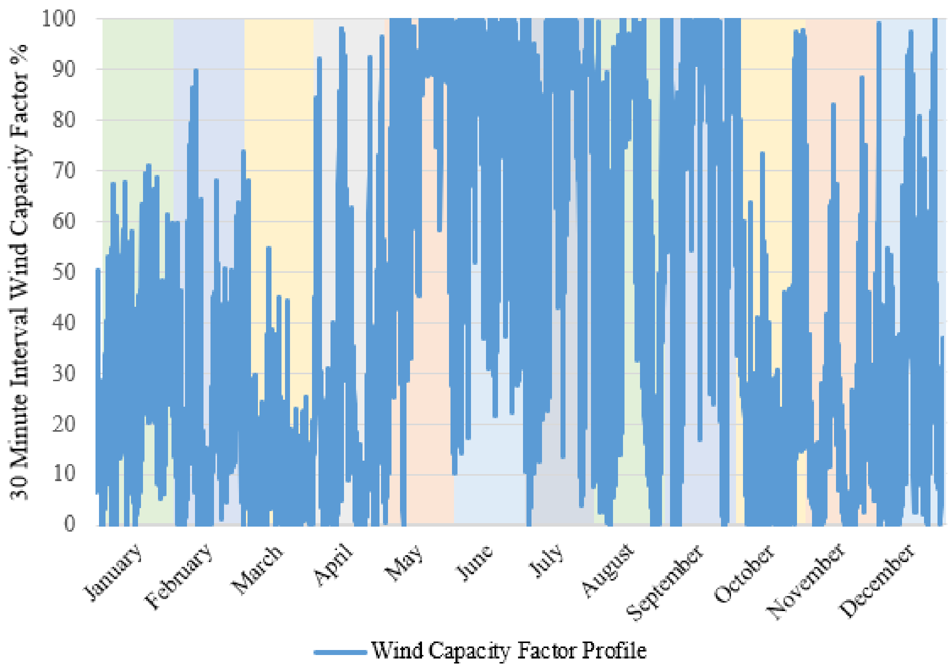

Figure 3.4: Annual capacity factor profile of wind generators

Annual installed capacities of biomass, mini hydro and wind power plants are given in Annex B.

Solar irradiance varies rapidly due to cloud movements and consequently the power output of solar PV systems varies rapidly. In addition, power output of solar PV systems shows a daily and seasonal variation due to the changes in the relative position of the sun. All these variations depend on the installed location of the solar PV system. Sri Lanka is located within the equatorial belt, a region where solar resource is available through the year and therefore, solar PV systems installed in Sri Lanka can reach high plant factors [20].

In order to capture daily and seasonal variations of power output of solar PV systems, a chronological generation profile is required. SAM developed by NREL contains solar resource data for nine (9) locations (Anuradhapura, Batticaloa, Katunayake, Ratmalana, Hambantota, Kankasanturai, Nuwara Eliya, Puttalam, and

Trincomalee) in Sri Lanka, which have been generated using satellite-based measurements. A 100 MW (AC) solar PV system was modelled in SAM, and the average profile of simulated annual power output profiles of all the nine locations was used as the solar PV capacity factor profile in the dispatch model.

Figure 3.5 depicts the monthly energy availability variation of a solar PV system located in Sri Lanka. Maximum and minimum amounts of energy occur in March and December, respectively.

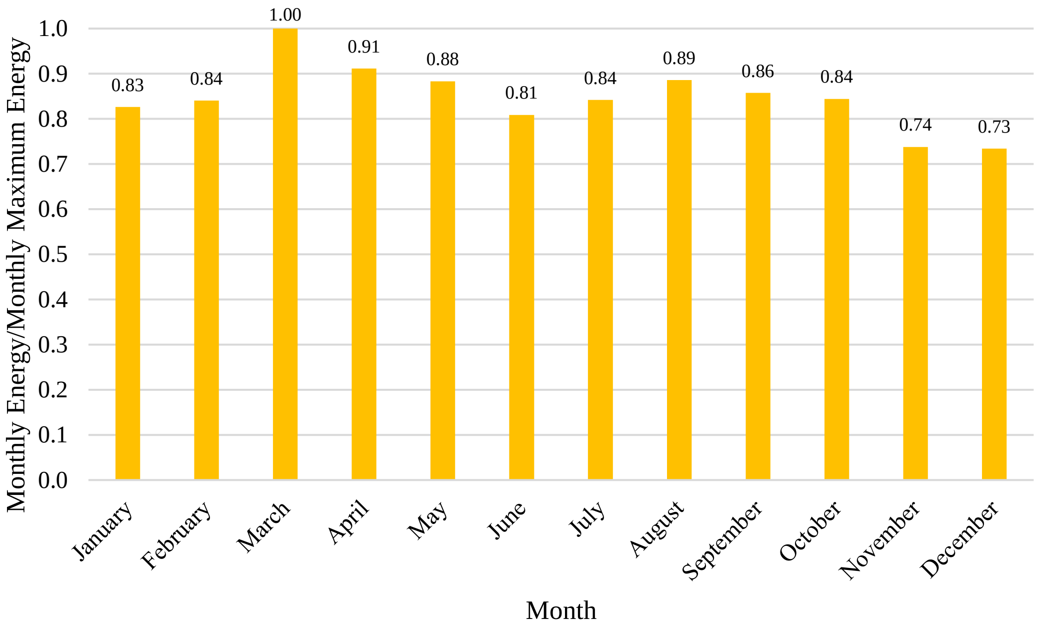

Figure 3.5: Monthly variation of average energy availability of a solar PV system in Sri Lanka

3.3.3 Reserve Provisions

Power output of solar PV systems can vary rapidly with cloud movements. The maximum variation in the power output in 5 minutes can be as high as 70% of the installed capacity [21]. When the capacity supplied from solar PV systems is a significant portion of the demand, these variations cause an unbalance between generation and demand, and subsequently affect the system frequency [22].

As explained in the section 2.3, maintaining an adequate amount of regulating reserves is sufficient to damp out frequency variations caused by the variability of solar PV electricity generation. In countries where power markets are operational, a clear demarcation between regulating and contingency reserves is available. As Sri Lanka is following the simple merit order principle to dispatch power plants, such a demarcation is not available. Even at a credible contingency event (eg: tripping of the largest generating unit), a load shedding scheme is initiated to maintain the system stability. In this context, it is not reasonable to assume that power systems operators will maintain both regulating and contingency reserves separately to maintain system frequency within the standards.

CEB LTGEP 2018-2037 has considered 5% of the installed capacity of intermittent resource based (solar and wind) generators as the regulating reserve requirement, and the capacity of the largest generating unit as the contingency reserve requirement. Sri Lanka's draft grid code specifies 2.5% as the minimum regulating reserve requirement to address the variability of the load. In this research, maximum of above three (3) types of reserves was considered as the required reserve provision.

Reserve Provision = Maximum {Capacity of the largest operating unit, 5% of the installed capacity of the solar and wind generators, 2.5% of the load)

Capacity of solar PV generators was considered in calculating regulating reserve requirement only during solar resource available hours.

3.3.4 Fuel Types

Sri Lanka imports total fossil fuel requirement for electricity generation. Auto Diesel, coal, fuel oil, naphtha and residual oil are being consumed by existing generators and it is planned to construct power plant which will be operated on natural gas (regasified liquid natural gas) in the near future. Based on the calorific value and content of sulphur, individual power plants consume sub categories of main fuel types. The dispatch model requires heat rate and variable O&M cost of individual power plants; and calorific value, and unit cost of fuel types to calculate variable unit cost of electricity generated by each power plant.

Since this is an economic analysis, present economic costs of fuels were used assuming that they will remain constant throughout the analysing period. Relevant parameters of fuel types are given in Table 3.7.

Table 3.7: Economic cost and calorific value of fuels [5]

Fuel Type	Economic Cost	Calorific Value (kcal/kg)
Auto Diesel	101.5 $/bbl	10,500
Naphtha	79.03 $/bbl	10,880
Fuel Oil (HSFO 180)	85.4 $/bbl	10,300
Fuel Oil (LSFO 180)	85.4 $/bbl	10,300
Residual Oil	85.4 $/bbl	10,300
Natural Gas	10 $/MMBtu	13,000
Coal (6,300 kcal/kg)	75.9 $/MT	6,300
Coal (5,900 kcal/kg)	69.8 $/MT	5,900

bbl = barrel, kcal= kilo calories, kg= kilogram, MMBtu = million British thermal units, MT = metric tons

Source: CEB LTGEP 2018-2037

3.4 Economic Benefits Evaluation Model

Concept of limitation of resources, makes the requirement of use of decision making parameters such as Net Present Value (NPV), Internal Rate of Return (IRR) and Benefits to Costs Ratio (BCR) to decide on an investment. When calculated using economic costs and benefits, those parameters can be used as tools to make decisions at national level. A spreadsheet based EBEM was developed to convert financial costs and benefits related solar PV capacity additions into economic domain, and to calculate the present value of net benefits of each solar PV penetration level.

Present value of net benefits of each solar PV penetration level should be calculated by comparing the costs and benefits of each solar PV penetration level with a common scenario, to select the solar PV penetration level with the maximum present value of net benefits. A 0% solar PV penetration level where no solar PV capacity is added after 2020, was defined for this purpose.

3.4.1 Economic Costs

In this research three (3) types of costs which are: i) capital cost; ii) fixed O&M cost; and iii) network augmentation cost related to solar PV capacity additions were considered.

Financial costs of solar PV systems have shown a rapid reduction and that has increased the financial viability of investing on solar PV systems. Financial cost of GML solar PV systems is 15% - 20% higher than the cost of rooftop solar PV systems due to additional costs of land acquisition and mounting structures. LKR 140,000 per kW and LKR 165,000 per kW were identified as the average capital costs of rooftop and GML solar PV systems in 2017 respectively.

In order to convert financial capital costs into economic capital costs, financial costs of rooftop solar PV systems and GML solar PV systems, were divided into cost components and categories, as shown in Table 3.8 and Table 3.9 respectively.

Table 3.8: Cost breakdown of rooftop solar PV systems

Cost Component	**Cost Share**	**Cost Category %**						
		Goods & Services		**Labour**				
		Tradeable	**Non-Tradeable**	**Foreign Skilled**	**Local Skilled**	**Unskilled**	**Land**	**Transfers**
Solar Panels	18%	100%	0%	0%	0%	0%	0%	0%
Inverter	10%	100%	0%	0%	0%	0%	0%	0%
Electrical BoS	8%	100%	0%	0%	0%	0%	0%	0%
Mechanical BoS	4%	100%	0%	0%	0%	0%	0%	0%
Installation	10%	20%	0%	0%	80%	0%	0%	0%
Land	0%	0%	0%	0%	0%	0%	100%	0%
Transport	11%	50%	0%	0%	50%	0%	0%	0%
Interconnection	2%	0%	0%	0%	0%	0%	0%	100%
Marketing	13%	0%	0%	0%	0%	0%	0%	100%
Overhead	24%	0%	0%	0%	0%	0%	0%	100%
Taxes	0%	0%	0%	0%	0%	0%	0%	100%

Table 3.9: Cost breakdown of ground mounted large solar PV systems

Cost Item	Cost Share	Cost Category %						
		Goods & Services		Labour			Land	Transfers
		Tradeable	Non-Tradeable	Foreign Skilled	Local Skilled	Unskilled		
Solar Panels	40%	100%	0%	0%	0%	0%	0%	0%
Inverter	5%	100%	0%	0%	0%	0%	0%	0%
Electrical BoS	7%	100%	0%	0%	0%	0%	0%	0%
Mechanical BoS	10%	100%	0%	0%	0%	0%	0%	0%
Installation	8%	20%	0%	20%	60%	0%	0%	0%
Land	3%	0%	0%	0%	0%	0%	100%	0%
Shipping	2%	50%	0%	0%	50%	0%	0%	0%
Interconnection	5%	50%	0%	0%	30%	0%	0%	20%
Marketing	0%	0%	0%	0%	0%	0%	0%	100%
Overhead	20%	0%	0%	0%	0%	0%	0%	100%
Taxes	0%	0%	0%	0%	0%	0%	0%	100%

Conversion factors given in Table 3.10 were applied to each cost category to convert financial costs into economic costs.

Table 3.10: Conversion factors used in the economic benefits evaluation model

Cost Category	Conversion Factor
Traded Goods (Standard Conversion Factor)	0.93
Non-Traded Goods	1.00
Foreign Skilled Labour	1.00
Local Skilled Labour	1.00
Unskilled Labour (Shadow Wage Rate Factor)	0.40
Land	1.00
Transfers	0.00

Standard Conversion Factor (SCF) is the reciprocal of the Shadow Exchange Rate Factor (SERF) which was calculated using (2) [10] and figures given in Table 3.11.

$$\text{SERF}= \frac{(M+T_m-S_m) + (X-T_x+S_x)}{M+X} \quad - (2)$$

Where;

M = Total value of imports

X = Total value of exports

Tm = Total taxes on imports

Tx = Total taxes on exports

S_m = Total subsidies on imports

S_x = Total subsidies on exports

Table 3.11: Calculation of standard conversion factor

	2015	**2016**	**2017**	**Average**
Imports (LKR million)	2,574,024	2,824,640	3,198,611	2,865,758
Exports (LKR million)	1,428,050	1,501,136	22,913,120	8,614,102
All Taxes on Imports (LKR million)	787,899	831,310	913,770	844,326
All Taxes on Export (LKR million)	-	-	-	-
Shadow Exchange Rate Factor (SERF)	1.20	1.19	2.37	1.07
Standard Conversion Factor (SCF)	0.84	0.84	0.84	0.84

Note: Data on subsidies are not available.

Shadow Wage Rate Factor (SWRF) was calculated using (3) [10] and relevant figures are given in Table 3.12.

$$\text{SWRF}= \frac{\text{Minimum Wage Paid in the Country}}{\text{Actual Wage Paid for Unskilled Labor in Solar PV Projects}} \quad - (3)$$

Table 3.12: Calculation of Shadow Wage Rate Factor

Minimum wage (LKR/day)	400
Actual wage (LKR/day)	1,000
Shadow Wage Rate Factor (SWRF)	0.40

NREL forecast a reduction of 40% of capital cost of solar PV systems by 2030 when compared with the costs in 2017 [7]. Although the forecast is for residential solar PV systems, the same forecast was applied to both rooftop and GML solar PV systems. Constant unit capital costs were used after 2030. Economic unit capital cost forecast of rooftop and GML solar PV systems is depicted in Figure 3.6.

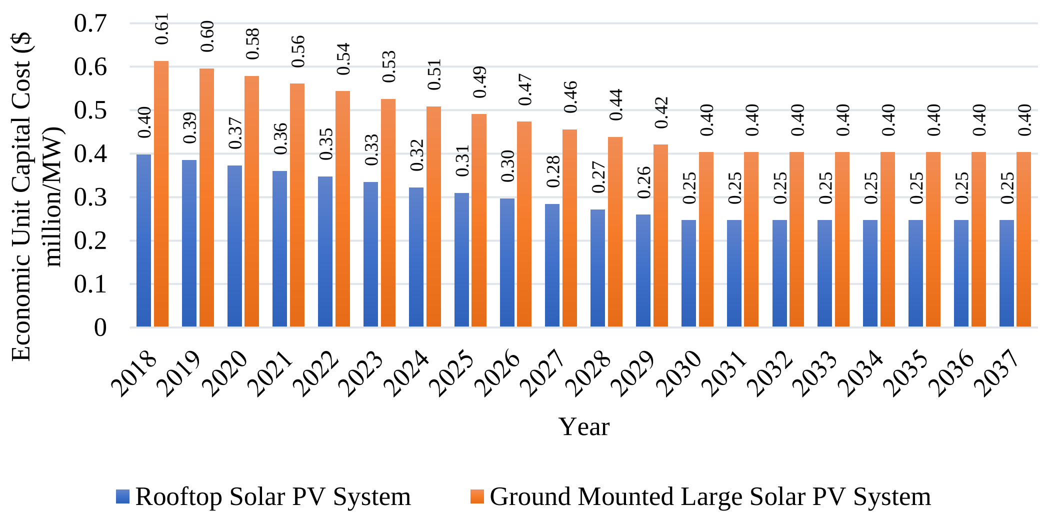

Figure 3.6: Economic unit capital cost forecast of solar PV systems

Increase in cost of land can affect the decrease in unit capital cost of GML solar PV systems. Developer's select areas where cost of land is low for GML solar PV systems and therefore, it was assumed that increase in cost of land doesn't make a significant impact on the unit cost of GML solar PV systems.

Table 3.13 provides solar PV capacity addition forecast breakdown up to 2020.

Table 3.13: Solar PV capacity addition forecast breakdown

Year	**Rooftop Solar PV Capacity (MW) (A)**	**Ground Mounted Large Solar PV Capacity (MW) (B)**	**A:B**
2016	32	1	96:4
2017	99	31	76:24
2018	170	51	76:24
2019	220	101	68:32
2020	270	151	64:36

Ratio between capacities of rooftop and GML solar PV systems is on the decline. With the plans of the government to build GML solar PV power plants with higher capacities, the ratio can be further decreased. Ratios between capacities of rooftop and GML solar PV systems under different solar PV penetration levels which were considered in the base case of this research are given in Table 3.14.

Table 3.14: Capacity share between rooftop and ground mounted large solar PV systems

Solar PV Penetration Level	**Capacity (% of the Total Solar PV Capacity)**	
	Rooftop Solar PV	**Ground Mounted Large Solar PV**
15%	65%	35%
20%	60%	40%
25%	55%	45%
30%	50%	50%
35%	45%	55%
40%	40%	60%
45%	35%	65%
50%	30%	70%

Economic fixed O&M costs were assumed to be 0.5% and 1% of the economic capital cost of rooftop and GML solar PV systems, respectively.

As discussed in 2.4, after connecting a certain rooftop solar PV capacity, the distribution network should be augmented to absorb more rooftop solar PV capacity without violating the operating criteria. Investments required for these augmentations should be considered as an additional economic cost. Studies have not been conducted to identify the actual threshold solar PV capacities, available network augmentation options, and related economic costs. In order to capture this additional cost in this research, it was assumed that 2% of the economic capital cost of rooftop solar PV systems as the network augmentation cost.

3.4.2 Economic Benefits

As discussed in the section 3.3, reduction in costs of fossil fuel imports and variable O&M costs of conventional thermal power plants are the economic benefits considered in this research. The dispatch model provides the total cost of fossil fuel and the total variable O&M cost under each solar PV penetration level. The EBEM calculates the difference of costs between each solar PV penetration level and the 0% solar PV penetration level. A conversion factor of 0.8 was used to convert financial variable O&M costs into economic costs.

3.4.3 Other Parameters in EBEM

In EBEM, present value of net benefits of 20 years (2018-2037) was calculated using a 10% discount rate. An exchange rate of 182 LKR/$ was used for currency conversions.

CHAPTER 4

OPTIMUM SOLAR PV CAPACITY ADDITION PLAN

This chapter discusses the outputs of the dispatch model and the EBEM.

4.1 Results of the Dispatch Model

4.1.1 Impact of Solar PV Penetration on Fuel Consumption

Hydro, coal and natural gas will be the dominant sources of electricity generation and the share of other fuels will be gradually reduced to negligible levels according to the base case of the CEB LTGEP 2018-2037. Therefore, detailed assessment is limited to hydro, coal and natural gas based electricity generation.

Figure 4.1 and Figure 4.2 depict the variation of the consumption of coal and natural gas with increasing solar PV penetration levels respectively.

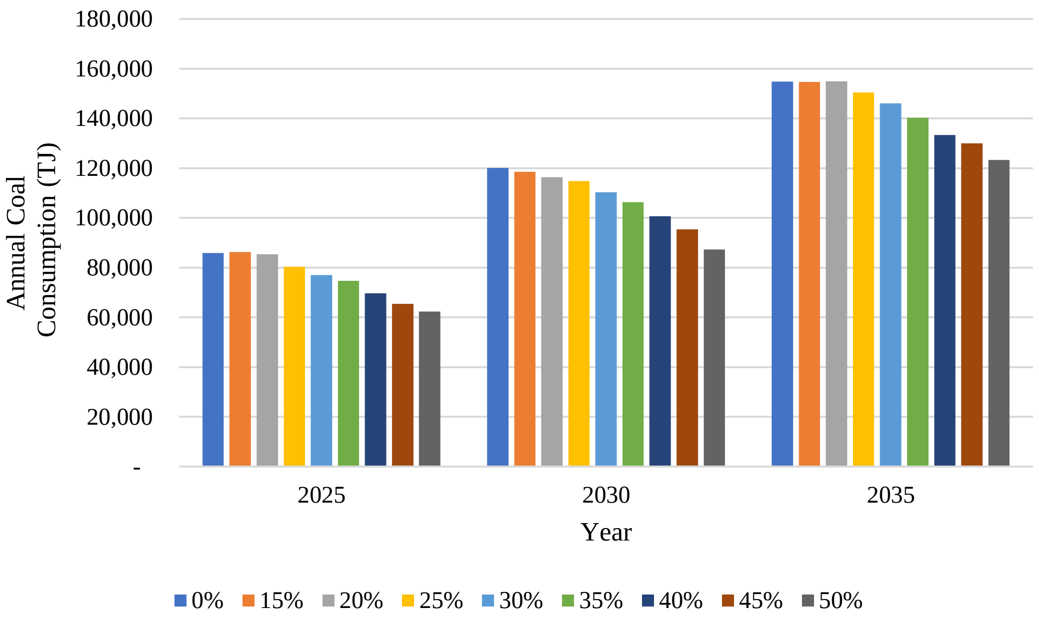

Figure 4.1: Variation of annual coal consumption under different solar PV penetration levels

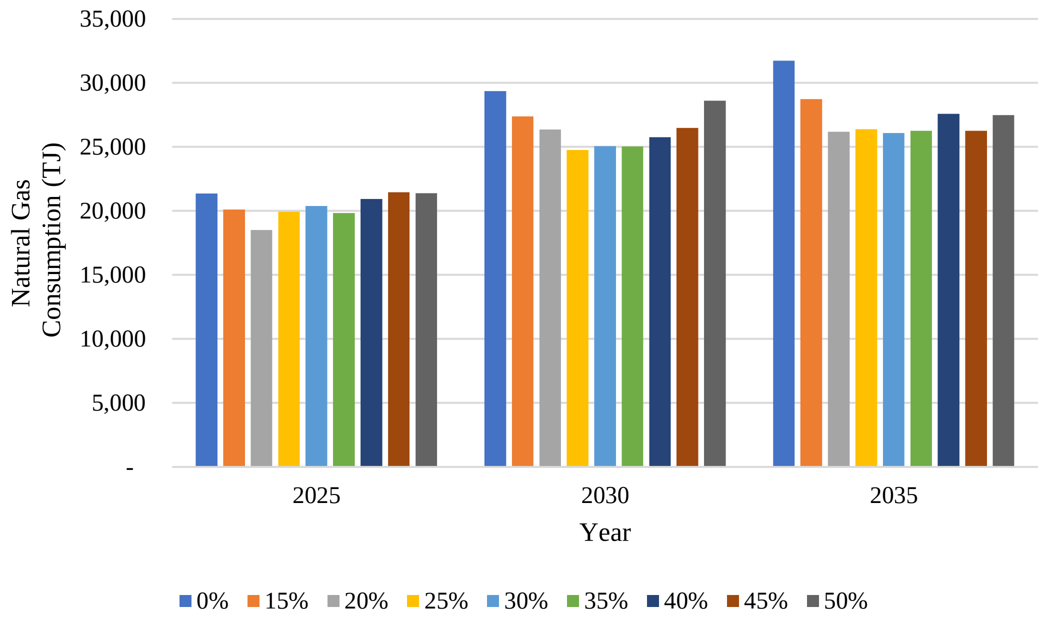

Figure 4.2: Variation of annual natural gas consumption under different solar PV penetration levels

A distinction between the patterns of the variations in coal and natural gas consumption can be observed. Coal consumption depicts a continuous reduction when solar PV penetration level is increased more than a triggering level. An annual variation in this triggering solar PV penetration level was observed. Both day peak demand and available capacities of different types of generators affect this triggering level.

Natural gas consumption has decreased with the increase in solar PV penetration level and reached a minimum level. Further increase in solar PV penetration level has caused an increase in natural gas consumption. This behaviour shows a correlation with the variation in coal consumption. Figure 4.3 and Figure 4.4 depicts the variation in coal and natural gas consumption under different solar PV penetration levels as a portion of the coal and natural gas consumption at the 0% solar PV penetration level in 2025 and 2035 respectively.

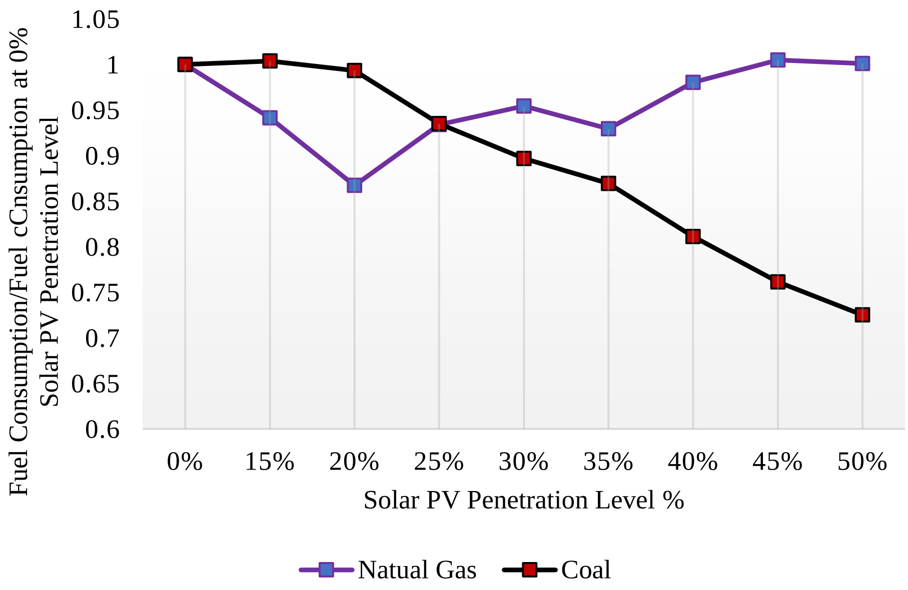

Figure 4.3: Correlation between coal and natural gas consumption in year 2025

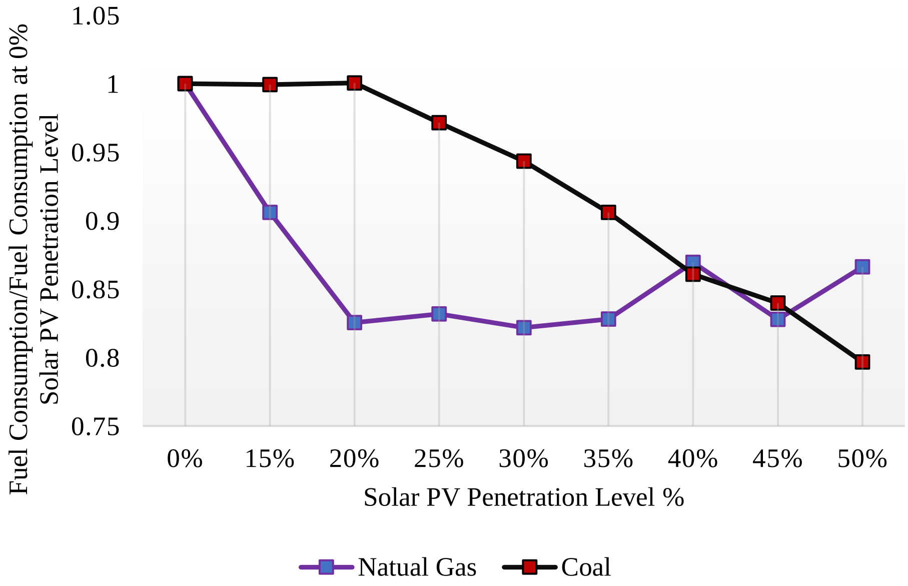

Figure 4.4: Correlation between coal and natural gas consumption in year 2035

Reduction in natural gas consumption has reached a minimum and then increased with the triggering of reduction in coal consumption. The analysis was further extended (section 4.1.2 and section 4.1.3) to find the reason for this behaviour using daily generation profiles. Scheduled and forced outages of generators can provide misleading results, if the analysis is limited to a randomly selected day, and therefore, an average generation profile was prepared using daily generation profiles of every day in the year.

4.1.2 Impact of Solar PV Penetration on Hydro Power Generation

Figure 4.5 depicts the variation in daily average hydro power generation profiles under several solar PV penetration levels in 2025.

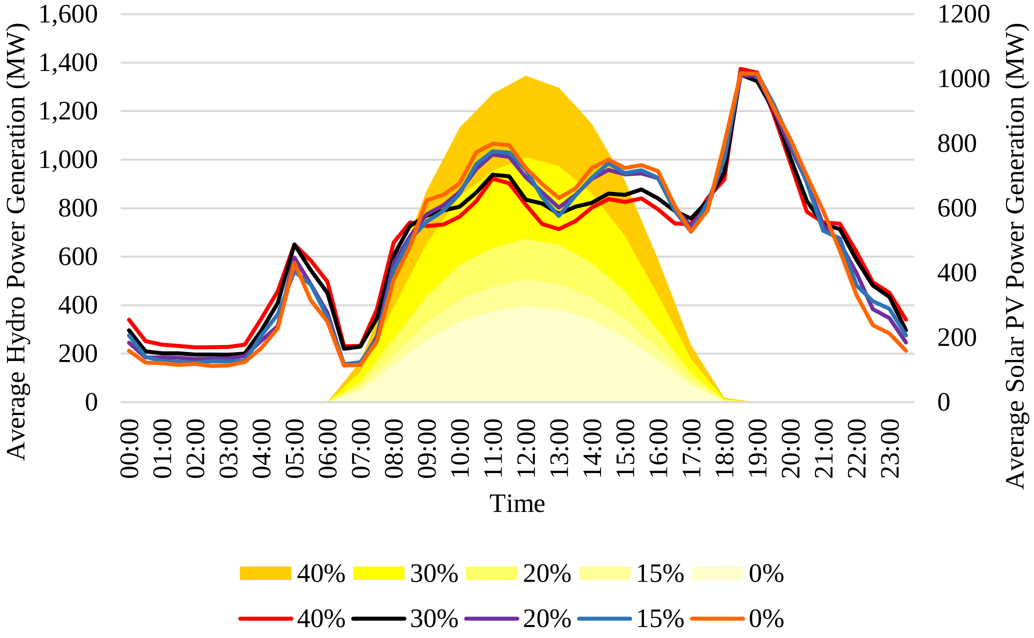

Figure 4.5: Variation in daily average hydro power generation profiles under different solar PV penetration levels in 2025

Note: Line and area charts are related to hydro and solar PV power generation, respectively.

When solar PV penetration level is increased, power output of hydro power plants decreases in intervals where solar PV power is available and increases in the off peak periods. Since hydro generators were modelled as energy constrained generators, monthly energy supply remains constant under all solar PV penetration levels.

If a longer interval is selected to constrain electricity generation of hydro power plants, flexibility of hydro generation can be increased and it will positively affect the increase in solar PV penetration level.

Figure 4.6 depicts the variation in daily average power generation profiles of natural gas based generators under several solar PV penetration levels in 2025.

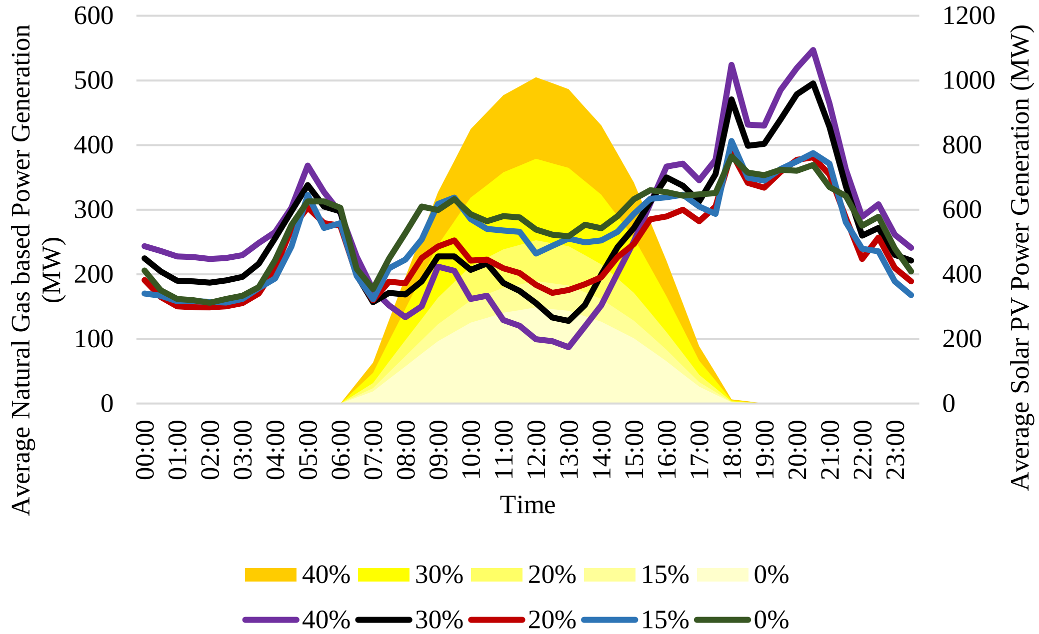

Figure 4.6: Variation in daily average power generation profiles of natural gas based generators under different solar PV penetration levels in 2025

Note: Line and area charts are related to natural gas and solar PV power generation respectively.

Similar to hydro power generation, natural gas based power generation has decreased when solar PV power generation is available and increased in both off peak and peak periods. Since natural gas based generators were modelled as unconstrained generators, a separate justification should be available for the increase in power output in off peak and peak durations.

4.1.3 Relationship Among Impacts on Coal, Natural Gas and Hydro Power Generation

Figure 4.7 depicts the variation in daily average power generation profiles of coal based generators under several solar PV penetration levels in 2025.

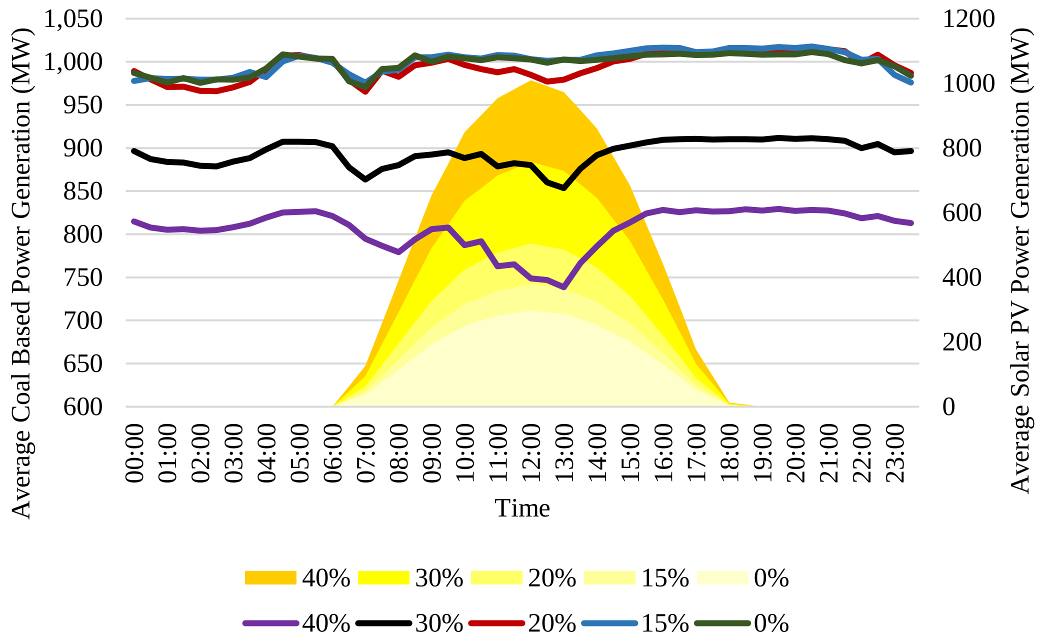

Figure 4.7: Variation in daily average power generation profiles of coal based generators under different solar PV penetration levels in 2025

Note: Line and area charts are related to coal and solar PV power generation respectively.

Coal based power generation shows a completely different behaviour. As discussed in above paragraphs, decrease in coal based power generation has been triggered at 30% solar PV penetration level. Rather than decreasing only at solar PV power generation available interval, coal based power generation shows a decrease throughout the day.

It is observed that, the decrease in coal based power generation in solar PV generation unavailable interval, is higher than the increase in hydro power generation (including pump hydro generation) in the same interval. Natural gas based generators have to increase the power output to reduce this difference and therefore, natural gas consumption has been increased with the increase in solar PV penetration level.

4.1.4 Impact of Solar PV Penetration on Total Fuel Cost

Table 4.1 provides the total annual fuel costs under different solar PV penetration levels.

Table 4.1: Total annual fuel costs under different solar PV penetration levels

Year	**Annual Total Fuel Cost under Different Solar PV Penetration Levels ($ million)**								
	0%	**15%**	**20%**	**25%**	**30%**	**35%**	**40%**	**45%**	**50%**
2018	423	423	423	423	423	423	423	423	423
2019	451	451	451	451	451	451	451	451	451
2020	446	446	446	446	446	446	446	446	446
2021	477	472	472	467	462	459	453	447	443
2022	510	500	499	492	480	468	458	451	446
2023	486	479	469	458	444	436	435	422	413
2024	488	480	462	445	439	430	421	411	404
2025	465	451	434	435	426	414	413	408	401
2026	516	506	490	473	466	463	453	456	453
2027	580	566	545	532	521	503	499	502	500
2028	535	515	510	507	500	497	498	493	488
2029	596	571	551	543	542	532	537	546	533
2030	658	633	613	590	585	574	572	568	577
2031	718	698	669	650	629	622	619	609	612
2032	703	667	648	623	608	601	601	609	590
2033	758	717	697	667	649	636	640	638	635
2034	821	772	749	736	704	685	680	671	668
2035	801	763	727	720	705	694	699	677	675
2036	879	823	814	775	749	739	736	728	720
2037	944	880	862	833	807	777	752	746	753

Figure 4.8 depicts the annual total fuel cost variation in 2025, 2030 and 2035.

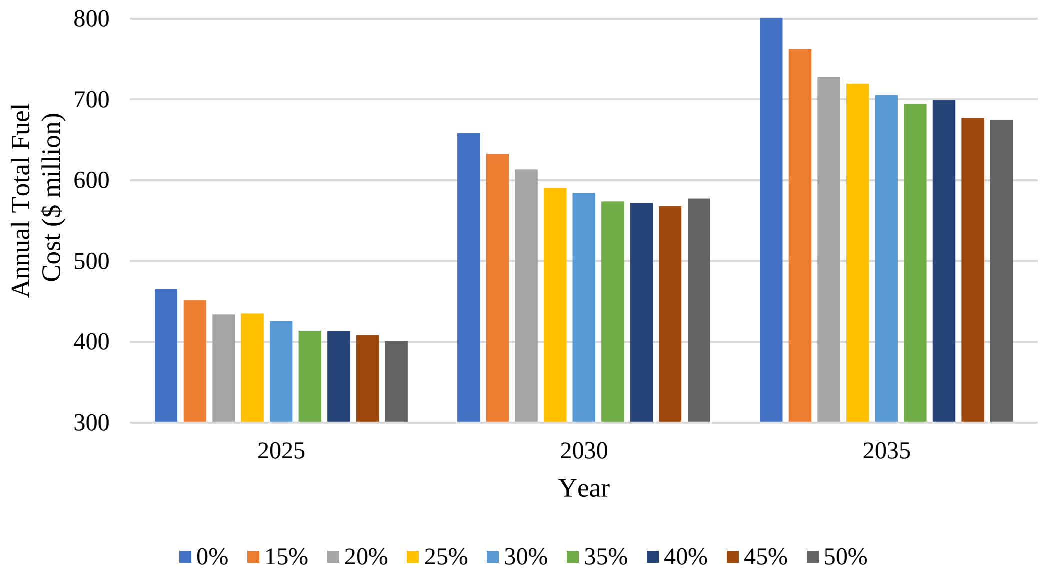

Figure 4.8: Annual variation of total fuel cost

Although an increase in the natural gas consumption is observed, total cost of fuel has decreased when the solar PV penetration level is increased. But the rate of cost reduction has decreased when reaching high solar PV penetration levels. This is clearer when fuel costs related to a single year is analysed as shown in Figure 4.9.

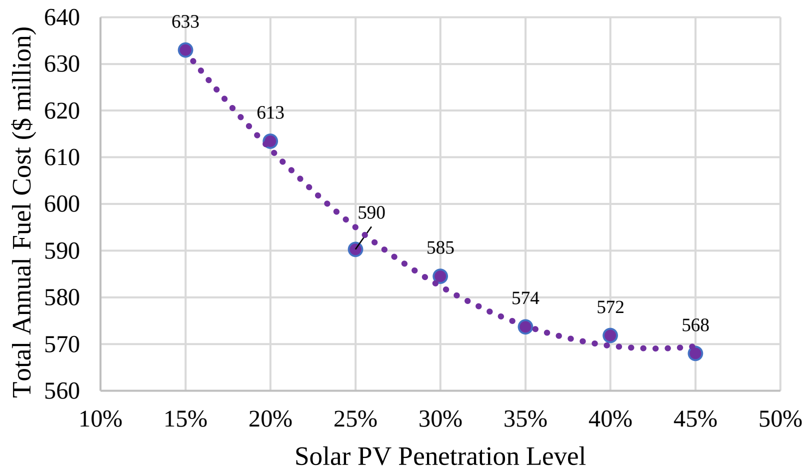

Figure 4.9: Total annual fuel costs under different solar PV penetration levels in 2025

At low solar PV penetration levels, electricity generated by solar PV systems displaces the electricity generated using high cost fuels such as natural gas. Displacement of electricity generated using coal which is a low cost fuel starts after the triggering solar PV penetration level. Additionally, an increase in natural gas consumption is also observed after the triggering solar PV penetration level. The rate of decrease in total annual fuel cost when reaching high solar PV penetration level occurs as a result of both reasons.

4.1.5 Impact of Solar PV Penetration on Variable O&M Cost

Table 4.2 provides the total annual variable O&M costs under different solar PV penetration levels.

Table 4.2: Total annual variable O&M costs under different solar PV penetration levels

Year	**Annual Total Variable O&M under Different Solar PV Penetration Levels ($ million)**								
	0%	**15%**	**20%**	**25%**	**30%**	**35%**	**40%**	**45%**	**50%**
2018	54	54	54	54	54	54	54	54	54
2019	52	52	52	52	52	52	52	52	52
2020	33	33	33	33	33	33	33	33	33
2021	35	34	34	34	34	33	33	32	32
2022	37	36	36	35	35	34	33	33	32
2023	42	42	41	40	39	39	38	37	36
2024	49	49	48	47	45	45	43	42	41
2025	58	57	56	54	52	51	48	46	44
2026	64	63	61	59	58	56	54	52	49
2027	68	67	65	63	61	60	58	56	54
2028	81	79	77	75	72	70	66	64	61
2029	85	83	82	79	77	75	72	69	66
2030	90	88	86	84	81	79	77	74	70
2031	95	92	90	88	86	83	81	78	75
2032	106	104	102	100	97	95	92	88	85

Year	Annual Total Variable O&M under Different Solar PV Penetration Levels ($ million)								
	0%	**15%**	**20%**	**25%**	**30%**	**35%**	**40%**	**45%**	**50%**
2033	116	113	111	108	106	104	100	97	93
2034	122	118	116	113	110	108	105	102	98
2035	129	126	124	121	117	114	110	107	103
2036	135	132	128	127	124	120	117	114	110
2037	140	137	133	131	129	126	123	120	115

Figure 4.10 depicts the annual total variable O&M cost variation in 2025, 2030 and 2035.

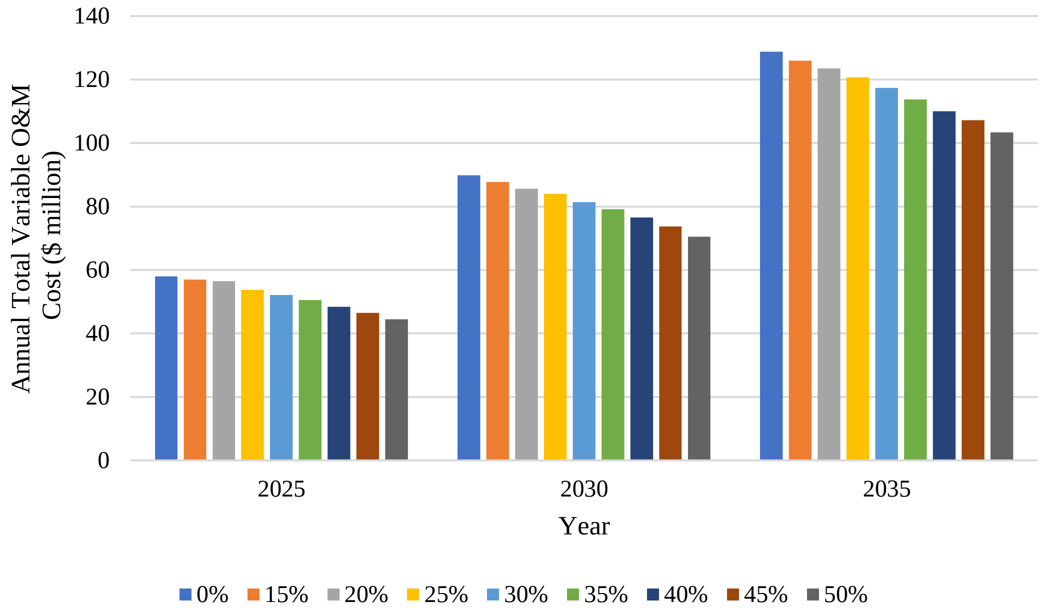

Figure 4.10: Annual total variable O&M cost variation

A continuous reduction in total annual variable O&M costs can be observed with the increase in solar PV penetration level.

4.2 Results of the Economic Benefits Evaluation Model

4.2.1 Optimum Solar PV Penetration Level

Detailed results available in the EBEM related to base case are given in Annex C, and Table 4.3 provides the present value of net benefits under each solar PV penetration level.

Table 4.3: Present values of net benefits of different solar PV penetration levels

Solar PV Penetration Level	Present Value of Net Benefits ($ million)
15%	56.0
20%	84.5
25%	103.8
30%	111.5
35%	106.2
40%	66.4
45%	29.1
50%	-11.9

Results were plotted in a graph as shown in Figure 4.11 and the maximum point was calculated using the equation of the trendline fitted to a polynomial.

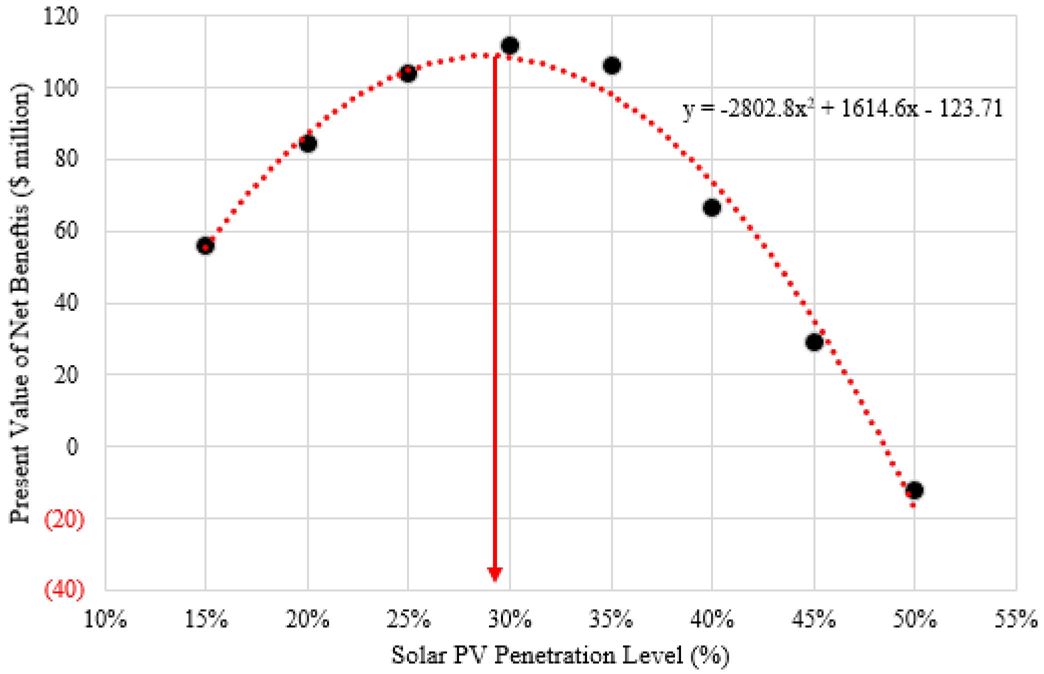

Figure 4.11: Variation of present value of net benefits

When solar PV penetration level is increased, present value of net benefits has also increased and reached a maximum point. After that, present value of net benefits has decreased and at 50% solar PV penetration level, it has become negative. Since present value of net benefits are positive for solar PV penetration levels below and equal to 45%, all those penetration levels are economically viable. But the present value of net benefits is maximized at the solar PV penetration level of 28.8%.

The nearest analysed solar PV penetration level to the optimum solar PV penetration level is 30% and therefore, from this point onwards 30% is referred as the optimum solar PV penetration level.

Detailed costs and benefits related to optimum solar PV penetration level are given in Table 4.4.

Table 4.4: Costs and benefits of the optimum solar PV penetration level

Year	Costs ($ million)			Benefits ($ million)		Net Benefits ($ million)
	Capital Cost	**Fixed O&M Cost**	**Distribution Network Augmentation Cost**	**Fuel Saving**	**Variable O&M Cost Saving**	
2018	0.0	0.0	0.0	0.0	0.0	0.0
2019	0.0	0.0	0.0	0.0	0.0	0.0
2020	0.0	0.0	0.0	0.0	0.0	0.0
2021	-71.4	-0.7	0.0	14.9	0.9	-56.4
2022	-57.4	-1.2	-0.4	29.6	1.7	-27.7
2023	-55.5	-1.6	-0.4	42.2	2.5	-12.9
2024	-53.5	-2.0	-0.4	48.4	3.3	-4.3
2025	-52.8	-2.5	-0.4	39.5	4.7	-11.5
2026	-23.9	-2.7	-0.2	50.1	4.9	28.3
2027	-24.4	-2.9	-0.2	59.1	5.6	37.3
2028	-24.8	-3.1	-0.2	35.1	6.6	13.6
2029	-24.8	-3.3	-0.2	54.4	6.5	32.6
2030	-25.3	-3.5	-0.2	73.6	6.8	51.4
2031	-20.8	-3.6	-0.2	89.3	7.3	72.0
2032	-21.4	-3.8	-0.2	94.6	7.1	76.2
2033	-21.7	-4.0	-0.2	109.5	8.5	92.1
2034	-22.4	-4.2	-0.2	116.5	9.1	98.8
2035	-23.7	-4.4	-0.2	95.7	9.1	76.6
2036	-24.7	-4.6	-0.2	130.3	8.9	109.7
2037	-25.6	-4.8	-0.2	137.0	9.0	115.5
					NPV ($ million)	**111.5**

The same data set has been depicted in Figure 4.12.

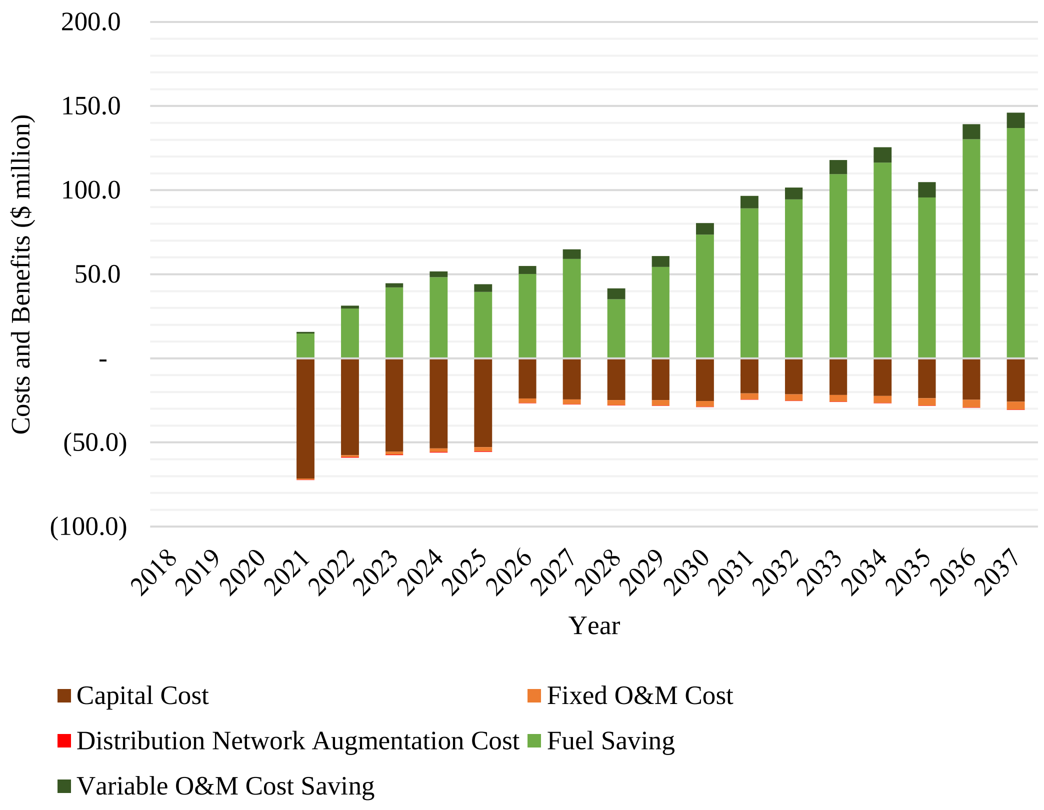

Figure 4.12: Costs and benefits of the optimum solar PV penetration level

Note: From 2018 to 2020 already committed solar PV systems will be built and therefore, costs and benefits for those years hasn't shown in the chart.

4.2.2 Sensitivity Analysis on Optimum Solar PV Penetration Level

Sensitivity studies were carried out to study the impact of variation of the cost related parameters on the optimum solar PV penetration level.

Results related to variation in the unit capital costs are given in Table 4.5 and depicted in Figure 4.13.

Table 4.5: Sensitivity study – Unit capital cost

	Sensitivities				
Variation of Unit Capital Cost (Both rooftop and GML solar PV systems)	-20%	-10%	0% (Base case)	10%	20%
Optimum Solar PV Penetration Level	34%	31%	29%	26%	24%
Variation	18%	8%	0%	-8%	-16%

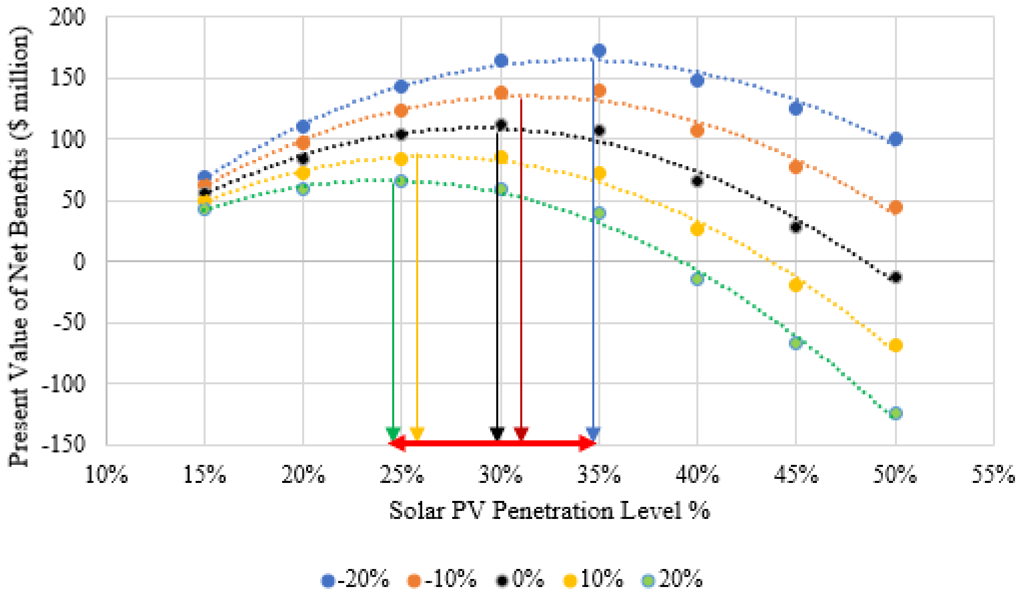

Figure 4.13: Sensitivity study – Unit capital cost

Results related to variation in the capital cost reduction by 2030 are given in Table 4.6 and depicted in Figure 4.14.

Table 4.6: Sensitivity study – Capital cost reduction by 2030

	Sensitivities				
Cost reduction percentage by 2030	0%	20%	40% (Base case)	50%	60%
Optimum Solar PV Penetration Level	23%	26%	29%	30%	32%
Variation	-19%	-10%	0%	5%	10%

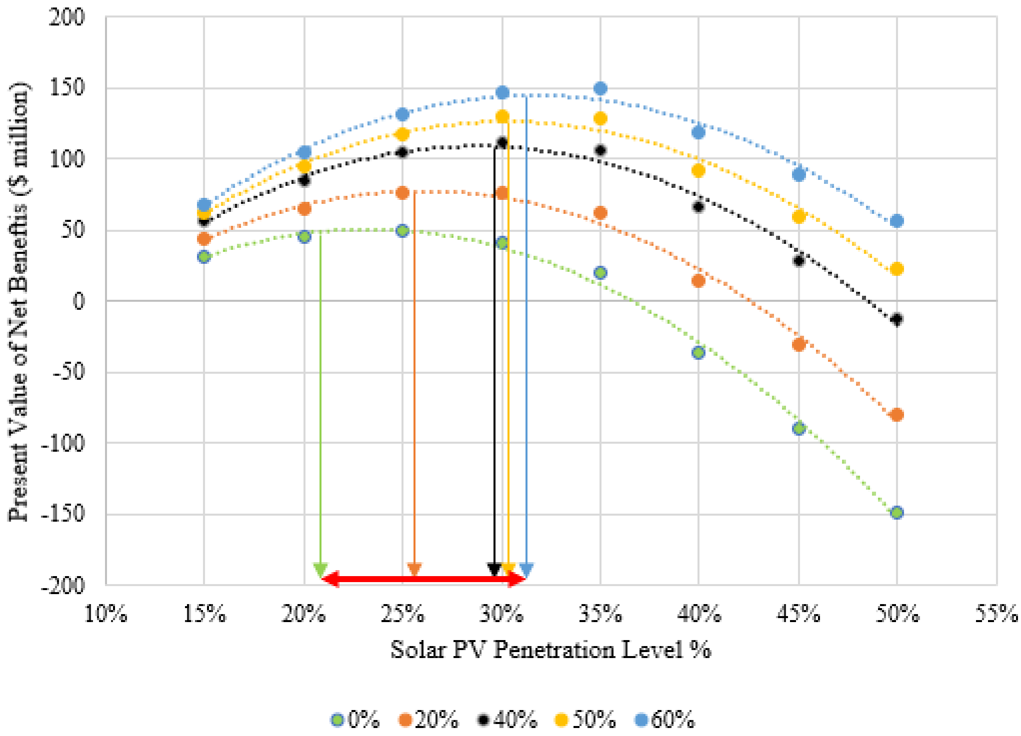

Figure 4.14: Sensitivity study – Capital cost reduction by 2030

Results related to variation in the distribution network augmentation cost percentage are given in Table 4.7 and depicted in Figure 4.15.

Table 4.7: Sensitivity study – Distribution network augmentation cost percentage

	Sensitivities				
Distribution network augmentation cost percentage	0%	1%	2% (Base case)	10%	20%
Optimum Solar PV Penetration Level	28.9%	28.8%	28.8%	28.5%	28.2%
Variation	0%	0%	0%	-1%	-2%

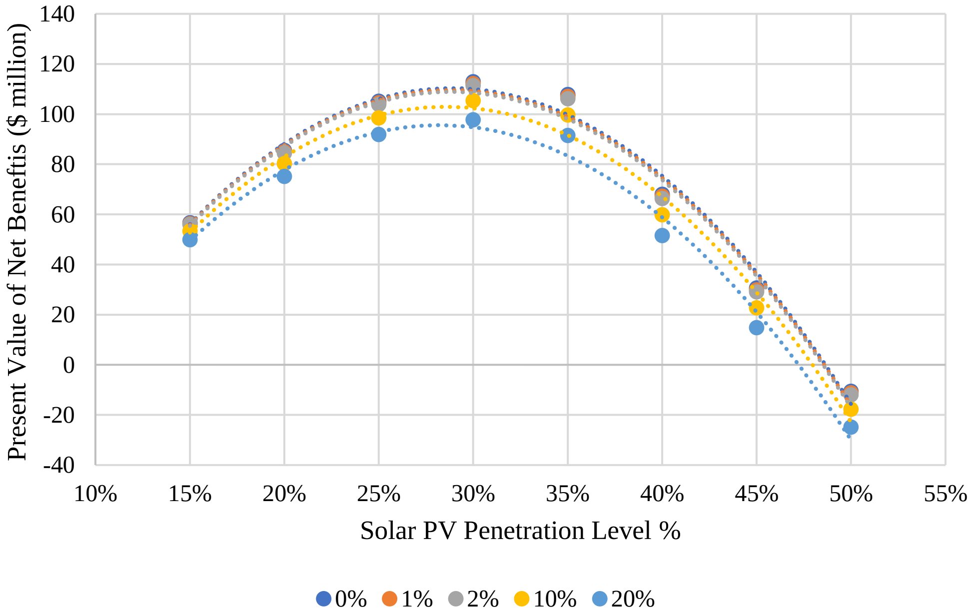

Figure 4.15: Sensitivity study – Distribution network augmentation cost percentage

Results related to variation in the fixed O&M cost percentage are given in Table 4.8 and depicted in Figure 4.16.

Table 4.8: Sensitivity study – Fixed O&M cost percentage

		Sensitivities				
Fixed O&M Cost Percentage	Rooftop	0.5%	1.0%	2.0%	3.0%	4.0%
	GML	1.0%	2.0%	3.0%	4.0%	5.0%
Optimum Solar PV Penetration Level		29%	27%	26%	24%	22%
Variation		0%	-6%	-11%	-17%	-23%

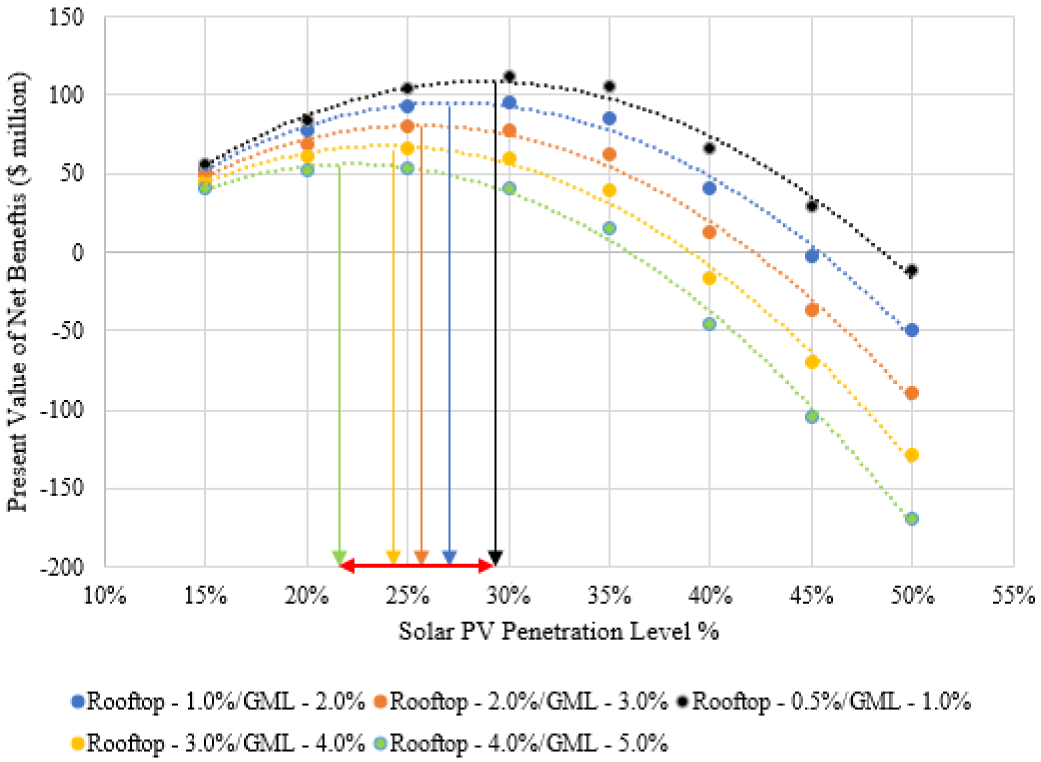

Figure 4.16: Sensitivity study – Fixed O&M cost percentage

Table 4.9 summarizes the results of the sensitivity study.

Table 4.9: Summary of the sensitivity study

Factor	**Sensitivity**
Capital cost	Moderate
Capital cost reduction by 2030	Moderate
Distribution network augmentation cost percentage	Low
Fixed O&M Cost percentage	Moderate

CHAPTER 5

CONCLUSIONS

5.1 Comparison of Results with Policy Targets

In this research present value of net benefits under different solar PV penetration levels were calculated using a dispatch model and an economic benefits evaluation model to identify optimum solar PV penetration level for Sri Lanka.

According to the results of the research, economic benefits are maximized at the solar PV penetration level of 30%. Solar PV capacity addition plan of the optimum solar PV penetration level has been depicted in Figure 5.1.

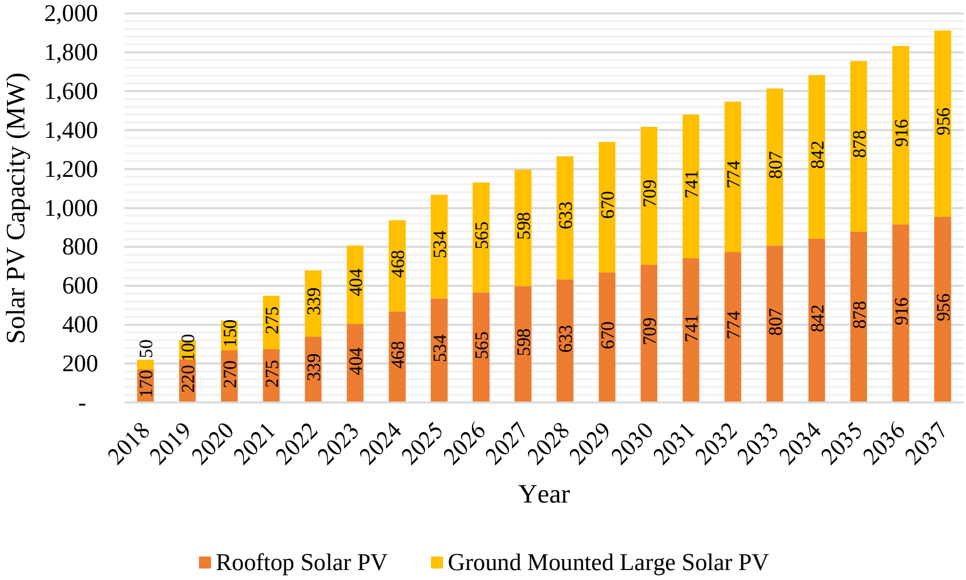

Figure 5.1: Solar PV capacity addition plan under the optimum solar PV penetration level

Table 5.1 compares the results of the research with the targets set in various documents which have been discussed in section 1.2.

Table 5.1: Comparison of the results with the targets of other studies

Year	Type	Results of the Study	Battle for Solar Program	ADB/UNDP Study	CEB LTGEP 2018-2037
2020	Rooftop	270 MW	200 MW	-	-
	GML	150 MW	-	-	-
	Total	420 MW	-	392 MW	410 MW
2025	Rooftop	534 MW	1000 MW	-	-
	GML	534 MW	-	-	-
	Total	1,068 MW	-	900 MW	685 MW
2030	Rooftop	709 MW	-	-	-
	GML	709 MW	-	-	-
	Total	1,417 MW	-	-	1,009 MW
2035	Rooftop	878 MW	-	-	-
	GML	878 MW	-	-	-
	Total	1,756 MW	-	-	1,283 MW

According to the short-term solar PV capacity addition forecast, rooftop solar PV capacity will exceed the target set for 2020 by the Battle for Solar programme. The same programme has set a target to install 1,000 MW of rooftop solar PV capacity by 2025. The analysis indicates that the optimum rooftop solar PV capacity for 2025 is 534 MW. But the optimum total solar PV capacity for 2025 is approximately 1,000 MW. Results of the collaborated study by ADB and UNDP for 2020 and 2025, approximately match with the results of this research. Solar PV capacities which are available in the base case of CEB LTGEP 2018-2037 is lower than the capacities of the optimum capacity addition plan derived in this research.

5.2 Limitations of the Research and Possible Improvements

The main assumption in this research is that capacity addition plan of other generators remains constant under all analysed solar PV penetration levels. This should be further studied using a long term generation expansion planning tool considering relevant constraints.

Increase in solar PV penetration level causes a decrease in system inertia, and it affects the frequency response of the system under disturbances. A low inertia can cause frequency instability issues. In this research system stability under analysed solar PV penetration levels was not studied. Feasibility of each solar PV penetration level should be studied through network stability studies.

In this research an assumed cost for distribution network augmentation was used. A detailed study should be conducted by applying the findings of the research carried out related to distribution level issues associated with integration of rooftop solar PV systems to find the feeder wise threshold rooftop solar PV penetration levels. The study should be further extended to recommend network augmentation options suitable for Sri Lankan distribution network with associated costs to absorb more rooftop solar PV capacity.

Utility scale batteries are emerging as a solution to the issues which are associated with the intermittent nature of the power generation of the solar PV systems [23]. Research are being carried out to increase the capacity and efficiency of the batteries while reducing the cost. This research has not covered the impact of integrating batteries to the Sri Lankan power system, which should be studied in detail covering both technical and economic aspects.

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ANNEX A: TECHNICAL PARAMETERS OF POWER PLANTS

Table A.1: Technical parameters of thermal and hydro power plants

Power Plant Name	Fuel Type	Maximum Unit Capacity (MW)	Minimum Stable Level (MW)	Heat Rate (GJ/MWh)	Variable O&M Charge ($/MWh)	Auxiliary Consumption (%)	Fixed Charge ($/kW/year)	Maintenance Rate (%)	Forced Outage Rate (%)	Mean Time to Repair (Hours)
Barge Mounted Plant	Fuel Oil (HSFO 180)	15	15	9.247	11.03	18	64.8	15.8	4.9	1,680
Kelanithissa Combined Cycle	Naphtha	165	102	7.74	3.01	2.65	24.72	8.2	8.4	72
Kelanithissa GT (New)	Auto Diesel	115	79	11.966	5.56	1.74	2.4	9.6	34.3	72
Kelanithissa GT (Old)	Auto Diesel	16.3	16.3	16.82	0.72	18.5	40.2	14.2	29	720
Lakvijaya Coal - Unit 1	Coal (6300 kcal/kg)	300	200	10.41	3.15	10	20.4	14.2	14	72
Lakvijaya Coal - Unit 2	Coal (6300 kcal/kg)	300	200	9.94	3.15	10	20.4	14.2	7.7	72
Lakvijaya Coal - Unit 3	Coal (6300 kcal/kg)	300	200	9.94	3.15	10	20.4	13.699	11.8	1,248
Northern Power	Fuel Oil (HSFO 180)	36	30	9.2759	26.47	16.6	15.24	13.69	8	72

Power Plant Name	Fuel Type	Maximum Unit Capacity (MW)	Minimum Stable Level (MW)	Heat Rate (GJ/MWh)	Variable O&M Charge ($/MWh)	Auxiliary Consumption (%)	Fixed Charge ($/kW/year)	Maintenance Rate (%)	Forced Outage Rate (%)	Mean Time to Repair (Hours)
Sapugaskanda (Station A)	Residual Oil	20	17.4	9.3972	6.34	13	112.2	12.9	11.1	840
Sapugaskanda (Station B)	Residual Oil	10	8.7	8.615	1.88	13	102.72	8.2	7.7	24
Sojitz Kelanithissa Combined Cycle	Auto Diesel	172	106	7.9537	1.15	5.14	12.84	10.4	8	1,248
Uthuru Janani	Fuel Oil (HSFO 180)	8	8	8.937	9.21	18	23.16	16.4	22.9	1,248
Yugadanavi Combined Cycle	Fuel Oil (LSFO 180)	300	186	9.4	12.94	2.65	26.4	16.4	8	168
150 MW Reciprocating Engines	Fuel Oil (HSFO 180)	15.78	1.5	9.25	6.34	5	28.56	-	-	720
300 MW Combined Cycle Power Plant	Natural Gas	300	186	9.4	4.31	2.65	26.4	-	-	1,080
300 MW Coal Power Plant	Coal (5900 kcal/kg)	300	150	8.09604	5.82	10	53.64	-	-	24
35 MW Gas Turbine	Auto Diesel	35.71	10.5	12.8	5.22	2	8.28	-	-	720
600 MW Supercritical Coal Power Plant	Coal (5900 kcal/kg)	600	300	7.66	5.82	6	57.48	-	-	-
Pump Hydro Power Plant	Hydro	200	-	-	-	-	-	-	-	-
Bowatenna	Hydro	40	2	-	-	-	-	8.2	5	1,200
Broadlands	Hydro	17.5	2	-	-	-	-	8.2	5	72

Power Plant Name	Fuel Type	Maximum Unit Capacity (MW)	Minimum Stable Level (MW)	Heat Rate (GJ/MWh)	Variable O&M Charge ($/MWh)	Auxiliary Consumption (%)	Fixed Charge ($/kW/year)	Maintenance Rate (%)	Forced Outage Rate (%)	Mean Time to Repair (Hours)
Canyon	Hydro	30	1.5	-	-	-	-	8.2	8	1,200
Gin Ganga	Hydro	10	2.00	-	-	-	-	8.2	8	72
Iginiyagala - 1	Hydro	2.47	0.12	-	-	-	-	8.2	8	1,128
Iginiyagala - 2	Hydro	3.15	0.15	-	-	-	-	8.2	8	72
Kotmale	Hydro	67	3.35	-	-	-	-	8	8	720
Kukule	Hydro	37.5	1.87	-	-	-	-	12.3	3	72
Moragahakanda	Hydro	2.5	0	-	-	-	-	12.3	3	72
Moragolla	Hydro	15.1	2	-	-	-	-	12.3	3	912
New Laxapana	Hydro	58	2.9	-	-	-	-	8.2	8	72
Nilambe	Hydro	1.6	0.08	-	-	-	-	8.2	8	1,440
Old Laxapana Stage 1	Hydro	9.6	0.48	-	-	-	-	8.2	8	72
Old Laxapana Stage 2	Hydro	12.5	0.62	-	-	-	-	8.2	8	1,440
Polpitiya	Hydro	37.5	1.87	-	-	-	-	8	8	72
Randenigala	Hydro	61.3	3.06	-	-	-	-	8.2	8	1,440
Rantambe	Hydro	25	1.25	-	-	-	-	8.2	8	72
Samanalawewa	Hydro	60	3	-	-	-	-	8.2	3	1,440
Seethawaka	Hydro	10	2	-	-	-	-	8	3	72

Power Plant Name	Fuel Type	Maximum Unit Capacity (MW)	Minimum Stable Level (MW)	Heat Rate (GJ/MWh)	Variable O&M Charge ($/MWh)	Auxiliary Consumption (%)	Fixed Charge ($/kW/year)	Maintenance Rate (%)	Forced Outage Rate (%)	Mean Time to Repair (Hours)
Thalpitigala	Hydro	7.5	2	-	-	-	-	8.2	3	1,440
Udawalawa	Hydro	2	0.1	-	-	-	-	8.2	8	72
Ukuwela	Hydro	20	1	-	-	-	-	8.2	1.7	720
Uma Oya	Hydro	61	2	-	-	-	-	8	8	24
Upper Kotmale	Hydro	75	3.75	-	-	-	-	12.3	8	720
Victoria	Hydro	70	0	-	-	-	-	12.3	-	24
Wimalasurendra	Hydro	25	1.25	-	-	-	-	12.3	-	720

Note: Fuel type of both Kelanithissa combined cycle and Sojitz combined cycle power plants will be switched to natural gas in 2023.

Table A.2: Number of units of generators

Power Plant Name	Number of Units																			
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Barge Mounted Plant	4	4	4	4	4	4	4	0	0	0	0	0	0	0	0	0	0	0	0	0
Kelanithissa Combined Cycle	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Power Plant Name	Number of Units																			
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Kelanithissa GT (New)	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Kelanithissa GT (Old)	4	4	4	4	4	4	4	4	4	4	4	4	4	4	0	0	0	0	0	0
Lakvijaya Coal - Unit 1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Lakvijaya Coal - Unit 2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Lakvijaya Coal - Unit 3	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Northern Power	6	6	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Sapugaskanda (Station A)	4	4	4	4	4	4	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Sapugaskanda (Station B)	8	8	8	8	8	4	4	0	0	0	0	0	0	0	0	0	0	0	0	0
Sojitz Kelanithissa Combined Cycle	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Uthuru Janani	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Yugadanavi Combined Cycle	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
15 MW Receprocating Engines	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21
35 MW Gas Turbine	0	2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
300 MW Coal Power Plant	0	0	0	0	0	1	2	3	3	3	3	3	3	3	3	3	3	3	3	3
600 MW Supercritical Coal Power Plant	0	0	0	0	0	0	0	0	0	0	1	1	1	2	2	2	2	3	3	3

Power Plant Name	Number of Units																			
	2018	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
300 MW Combined Cycle Power Plant	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	3	3	3	4	4
Bowatenna	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Broadlands	0	0	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Canyon	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Gin Ganga	0	0	0	0	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Iginiyagala - 1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Moragahakanda	1	1	2	2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Kotmale	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Kukule	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Moragolla	0	0	0	0	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
New Laxapana	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Nilambe	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Old Laxapana Stage 1	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Old Laxapana Stage 2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Polpitiya	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Randenigala	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Rantambe	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2

Power Plant Name	Number of Units																			
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Samanalawewa	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Seethawaka	0	0	0	0	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Thalpitigala	0	0	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Udawalawa	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Ukuwela	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Uma Oya	0	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Upper Kotmale	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Victoria	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Wimalasurendra	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2

ANNEX B: ANNUAL INSTALLED CAPACITIES OF RENEWABLE ENERGY POWER PLANTS

Table B.1: Installed capacities of renewable energy power plants

Year	Installed Capacity (MW)		
	Wind	Mini hydro	Biomass
2018	143	379	36
2019	193	394	41
2020	413	409	46
2021	488	419	51
2022	538	429	56
2023	598	439	61
2024	643	449	66
2025	728	459	71
2026	728	469	76
2027	753	479	81
2028	798	489	86
2029	823	499	91
2030	893	509	96
2031	933	519	101
2032	973	529	101
2033	1,043	539	106
2034	1,113	549	106
2035	1,183	559	111
2036	1,278	569	111
2037	1,348	579	116

ANNEX C: DETAILED RESULTS OF THE ECONOMIC BENEFITS EVALUATION MODEL RELATED TO BASE CASE

Total Installed Solar PV Capacity (MW)																				
	2018	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
0%	220	320	420	420	420	420	420	420	420	420	420	420	420	420	420	420	420	420	420	420
15%	220	320	420	442	464	486	508	534	565	598	633	669	708	740	773	807	841	878	916	955
20%	220	320	420	478	536	594	652	712	753	797	844	893	945	987	1,031	1,076	1,122	1,170	1,221	1,274
25%	220	320	420	514	608	702	796	890	942	996	1,055	1,116	1,181	1,234	1,289	1,345	1,403	1,463	1,526	1,593
30%	220	320	420	549	678	807	936	1,068	1,130	1,196	1,266	1,339	1,417	1,481	1,547	1,614	1,683	1,756	1,832	1,911
35%	220	320	420	585	750	915	1,080	1,246	1,318	1,395	1,477	1,563	1,654	1,728	1,804	1,883	1,964	2,048	2,137	2,230
40%	220	320	420	620	820	1,020	1,220	1,424	1,507	1,595	1,688	1,786	1,890	1,975	2,062	2,152	2,244	2,341	2,442	2,548
45%	220	320	420	656	892	1,128	1,364	1,602	1,695	1,794	1,899	2,009	2,126	2,222	2,320	2,421	2,525	2,634	2,748	2,867
50%	220	320	420	692	964	1,236	1,508	1,780	1,884	1,993	2,110	2,232	2,363	2,469	2,578	2,690	2,806	2,927	3,053	3,186

Capacity Share (MW) - Rooftop																				
	2018	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
15%	-	-	-	65%	65%	65%	65%	65%	65%	65%	65%	65%	65%	65%	65%	65%	65%	65%	65%	65%
20%	-	-	-	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%
25%	-	-	-	55%	55%	55%	55%	55%	55%	55%	55%	55%	55%	55%	55%	55%	55%	55%	55%	55%
30%	-	-	-	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%
35%	-	-	-	45%	45%	45%	45%	45%	45%	45%	45%	45%	45%	45%	45%	45%	45%	45%	45%	45%
40%	-	-	-	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%
45%	-	-	-	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%

50%	-	-	-	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%
Capacity Share (MW) - Ground Mounted																				
	2018	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
15%	-	-	-	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%
20%	-	-	-	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%
25%	-	-	-	45%	45%	45%	45%	45%	45%	45%	45%	45%	45%	45%	45%	45%	45%	45%	45%	45%
30%	-	-	-	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%
35%	-	-	-	55%	55%	55%	55%	55%	55%	55%	55%	55%	55%	55%	55%	55%	55%	55%	55%	55%
40%	-	-	-	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%
45%	-	-	-	65%	65%	65%	65%	65%	65%	65%	65%	65%	65%	65%	65%	65%	65%	65%	65%	65%
50%	-	-	-	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%
Total Installed Rooftop Solar PV Capacity (MW)																				
	2018	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
0%	170	220	270	270	270	270	270	270	270	270	270	270	270	270	270	270	270	270	270	270
15%	170	220	270	287	302	316	330	347	367	389	411	435	460	481	502	525	547	571	595	621
20%	170	220	270	287	322	356	391	427	452	478	506	536	567	592	619	646	673	702	733	764
25%	170	220	270	283	334	386	438	490	518	548	580	614	650	679	709	740	772	805	839	876
30%	170	220	270	275	339	404	468	534	565	598	633	670	709	741	774	807	842	878	916	956
35%	170	220	270	263	338	412	486	561	593	628	665	703	744	778	812	847	884	922	962	1,004
40%	170	220	270	248	328	408	488	570	603	638	675	714	756	790	825	861	898	936	977	1,019
45%	170	220	270	230	312	395	477	561	593	628	665	703	744	778	812	847	884	922	962	1,003
50%	170	220	270	208	289	371	452	534	565	598	633	670	709	741	773	807	842	878	916	956
Total Installed Ground Mounted Solar PV Capacity (MW)																				

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
0%	50	100	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150
15%	50	100	150	155	162	170	178	187	198	209	222	234	248	259	271	282	294	307	321	334
20%	50	100	150	191	214	238	261	285	301	319	338	357	378	395	412	430	449	468	488	510
25%	50	100	150	231	274	316	358	401	424	448	475	502	531	555	580	605	631	658	687	717
30%	50	100	150	275	339	404	468	534	565	598	633	670	709	741	774	807	842	878	916	956
35%	50	100	150	322	413	503	594	685	725	767	812	860	910	950	992	1,036	1,080	1,126	1,175	1,227
40%	50	100	150	372	492	612	732	854	904	957	1,013	1,072	1,134	1,185	1,237	1,291	1,346	1,405	1,465	1,529
45%	50	100	150	426	580	733	887	1,041	1,102	1,166	1,234	1,306	1,382	1,444	1,508	1,574	1,641	1,712	1,786	1,864
50%	50	100	150	484	675	865	1,056	1,246	1,319	1,395	1,477	1,562	1,654	1,728	1,805	1,883	1,964	2,049	2,137	2,230
Incremental Rooftop Solar PV Capacity (MW)																				
	2018	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
0%	70	50	50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
15%	70	50	50	17	14	14	14	17	20	21	23	23	25	21	21	22	22	24	25	25
20%	70	50	50	17	35	35	35	36	25	26	28	29	31	25	26	27	28	29	31	32
25%	70	50	50	13	52	52	52	52	29	30	32	34	36	29	30	31	32	33	35	37
30%	70	50	50	5	65	65	65	66	31	33	35	37	39	32	33	34	35	37	38	40
35%	70	50	50	-7	74	74	74	75	32	35	37	39	41	33	34	36	36	38	40	42
40%	70	50	50	-22	80	80	80	82	33	35	37	39	42	34	35	36	37	39	40	42
45%	70	50	50	-40	83	83	83	83	33	35	37	39	41	34	34	35	36	38	40	42
50%	70	50	50	-62	82	82	82	82	31	33	35	37	39	32	33	34	35	36	38	40
Incremental Rooftop Solar PV Capacity (MW)																				
	2018	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
0%	20	50	50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

15%	20	50	50	5	8	8	8	9	11	12	12	13	14	11	12	12	12	13	13	14
20%	20	50	50	41	23	23	23	24	16	18	19	20	21	17	18	18	18	19	20	21
25%	20	50	50	81	42	42	42	42	23	24	27	27	29	24	25	25	26	27	28	30
30%	20	50	50	125	65	65	65	66	31	33	35	37	39	32	33	34	35	37	38	40
35%	20	50	50	172	91	91	91	91	40	42	45	47	50	41	42	43	45	46	49	51
40%	20	50	50	222	120	120	120	122	50	53	56	59	62	51	52	54	55	58	61	64
45%	20	50	50	276	153	153	153	155	60	64	68	72	76	62	64	66	68	71	74	77
50%	20	50	50	334	190	190	190	190	73	76	82	85	92	74	76	78	81	85	88	93
Unit Capital Cost ($ million/MW)																				
	2018	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
Rooftop Solar PV System	0.40	0.39	0.37	0.36	0.35	0.33	0.32	0.31	0.30	0.28	0.27	0.26	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
Ground Mounted Solar PV System	0.61	0.60	0.58	0.56	0.54	0.53	0.51	0.49	0.47	0.46	0.44	0.42	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40
Rooftop Solar PV System Capital Cost ($ Million)																				
	2018	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
0%	27.8	19.3	18.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
15%	27.8	19.3	18.6	6.2	5.0	4.8	4.6	5.2	6.0	6.1	6.2	6.1	6.2	5.1	5.3	5.4	5.4	5.9	6.1	6.2
20%	27.8	19.3	18.6	6.0	12.1	11.6	11.2	11.1	7.3	7.5	7.7	7.6	7.7	6.2	6.5	6.6	6.8	7.1	7.5	7.8
25%	27.8	19.3	18.6	4.6	18.0	17.3	16.7	16.0	8.5	8.4	8.8	8.7	8.8	7.2	7.5	7.6	7.9	8.1	8.5	9.1
30%	27.8	19.3	18.6	1.6	22.4	21.6	20.8	20.4	9.2	9.4	9.5	9.5	9.6	7.9	8.1	8.3	8.5	9.0	9.4	9.7
35%	27.8	19.3	18.6	-2.4	25.8	24.9	23.9	23.1	9.6	9.8	10.0	10.0	10.1	8.2	8.4	8.8	9.0	9.3	9.9	10.3

40%	27.8	19.3	18.6	-7.9	27.8	26.8	25.8	25.2	9.9	10.0	10.1	10.1	10.2	8.4	8.6	8.9	9.1	9.6	9.9	10.4
45%	27.8	19.3	18.6	-14.5	28.7	27.6	26.6	25.8	9.7	9.8	10.0	10.0	10.1	8.3	8.4	8.7	9.0	9.4	9.8	10.3
50%	27.8	19.3	18.6	-22.5	28.3	27.3	26.3	25.2	9.3	9.3	9.5	9.5	9.7	7.8	8.1	8.3	8.6	8.9	9.3	9.8
Ground Mounted Solar PV System Capital Cost ($ Million)																				
	2018	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
0%	12.3	29.8	28.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
15%	12.3	29.8	28.9	2.6	4.2	4.0	3.9	4.5	5.1	5.3	5.4	5.3	5.5	4.5	4.7	4.8	4.8	5.2	5.4	5.5
20%	12.3	29.8	28.9	23.1	12.6	12.2	11.8	11.8	7.8	8.0	8.2	8.2	8.4	6.8	7.1	7.3	7.4	7.7	8.2	8.5
25%	12.3	29.8	28.9	45.6	23.0	22.2	21.5	20.8	11.1	11.1	11.6	11.5	11.8	9.6	10.0	10.2	10.5	10.9	11.4	12.1
30%	12.3	29.8	28.9	69.8	35.0	33.9	32.8	32.4	14.7	15.0	15.3	15.3	15.7	12.9	13.3	13.5	13.9	14.7	15.3	15.9
35%	12.3	29.8	28.9	96.3	49.3	47.7	46.1	44.8	18.7	19.3	19.8	19.9	20.2	16.4	16.8	17.5	18.0	18.6	19.7	20.6
40%	12.3	29.8	28.9	124.5	65.2	63.1	61.0	60.0	23.6	24.1	24.4	24.7	25.1	20.6	21.0	21.8	22.2	23.5	24.4	25.6
45%	12.3	29.8	28.9	155.0	83.3	80.6	77.9	75.9	28.6	29.3	29.9	30.1	30.6	25.1	25.7	26.5	27.2	28.6	29.9	31.2
50%	12.3	29.8	28.9	187.5	103.4	100.1	96.7	93.4	34.4	34.8	35.9	35.9	37.0	29.9	30.7	31.6	32.7	34.1	35.5	37.5
Total Capital Cost ($ million)																				
	2018	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
0%	40.1	49.0	47.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
15%	40.1	49.0	47.5	8.9	9.1	8.8	8.5	9.7	11.1	11.4	11.5	11.4	11.7	9.6	9.9	10.2	10.2	11.1	11.4	11.7
20%	40.1	49.0	47.5	29.1	24.7	23.8	23.0	22.9	15.1	15.5	15.9	15.9	16.1	13.0	13.6	13.9	14.2	14.8	15.8	16.4
25%	40.1	49.0	47.5	50.2	40.9	39.5	38.1	36.7	19.6	19.5	20.4	20.2	20.6	16.8	17.4	17.7	18.4	19.0	20.0	21.2
30%	40.1	49.0	47.5	71.4	57.4	55.5	53.5	52.8	23.9	24.4	24.8	24.8	25.3	20.8	21.4	21.7	22.4	23.7	24.7	25.6
35%	40.1	49.0	47.5	93.9	75.1	72.6	70.0	67.9	28.3	29.1	29.8	29.9	30.3	24.6	25.3	26.3	26.9	27.9	29.6	30.9
40%	40.1	49.0	47.5	116.5	93.0	89.8	86.7	85.3	33.4	34.1	34.5	34.9	35.4	28.9	29.6	30.6	31.3	33.0	34.4	36.1
45%	40.1	49.0	47.5	140.4	112.0	108.3	104.5	101.7	38.3	39.2	39.9	40.0	40.7	33.4	34.1	35.2	36.2	37.9	39.7	41.4

50%	40.1	49.0	47.5	165.0	131.8	127.4	123.0	118.7	43.7	44.0	45.4	45.4	46.6	37.7	38.8	39.9	41.3	43.1	44.9	47.3
Fixed O&M Cost %																				
	2018	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
Rooftop Solar PV System	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%
Ground Mounted Solar PV System	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%
Rooftop Solar PV - Fixed O&M Cost ($ million)																				
	2018	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
0%	0.3	0.4	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
15%	0.3	0.4	0.5	0.6	0.6	0.6	0.6	0.7	0.7	0.7	0.7	0.8	0.8	0.8	0.9	0.9	0.9	0.9	1.0	1.0
20%	0.3	0.4	0.5	0.6	0.6	0.7	0.7	0.8	0.8	0.9	0.9	0.9	1.0	1.0	1.0	1.1	1.1	1.1	1.2	1.2
25%	0.3	0.4	0.5	0.6	0.6	0.7	0.8	0.9	0.9	1.0	1.0	1.1	1.1	1.1	1.2	1.2	1.3	1.3	1.3	1.4
30%	0.3	0.4	0.5	0.5	0.6	0.8	0.9	1.0	1.0	1.1	1.1	1.1	1.2	1.2	1.3	1.3	1.4	1.4	1.5	1.5
35%	0.3	0.4	0.5	0.5	0.6	0.8	0.9	1.0	1.1	1.1	1.2	1.2	1.3	1.3	1.3	1.4	1.4	1.5	1.5	1.6
40%	0.3	0.4	0.5	0.5	0.6	0.8	0.9	1.0	1.1	1.1	1.2	1.2	1.3	1.3	1.4	1.4	1.4	1.5	1.5	1.6
45%	0.3	0.4	0.5	0.5	0.6	0.7	0.9	1.0	1.0	1.1	1.1	1.2	1.2	1.3	1.3	1.4	1.4	1.5	1.5	1.6
50%	0.3	0.4	0.5	0.4	0.6	0.7	0.8	1.0	1.0	1.0	1.1	1.1	1.2	1.2	1.3	1.3	1.4	1.4	1.4	1.5
Ground Mounted Solar PV - Fixed O&M Cost ($ million)																				
	2018	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
0%	0.3	0.6	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9

15%	0.3	0.6	0.9	0.9	1.0	1.0	1.0	1.1	1.1	1.2	1.2	1.3	1.4	1.4	1.4	1.5	1.5	1.6	1.6	1.7
20%	0.3	0.6	0.9	1.1	1.3	1.4	1.5	1.6	1.7	1.8	1.8	1.9	2.0	2.1	2.2	2.2	2.3	2.4	2.5	2.5
25%	0.3	0.6	0.9	1.3	1.6	1.8	2.0	2.2	2.3	2.4	2.6	2.7	2.8	2.9	3.0	3.1	3.2	3.3	3.4	3.5
30%	0.3	0.6	0.9	1.6	1.9	2.3	2.6	2.9	3.1	3.2	3.4	3.5	3.7	3.8	4.0	4.1	4.2	4.4	4.5	4.7
35%	0.3	0.6	0.9	1.9	2.3	2.8	3.3	3.7	3.9	4.1	4.3	4.5	4.7	4.9	5.0	5.2	5.4	5.6	5.8	6.0
40%	0.3	0.6	0.9	2.1	2.8	3.4	4.0	4.6	4.9	5.1	5.4	5.6	5.9	6.1	6.3	6.5	6.7	6.9	7.2	7.4
45%	0.3	0.6	0.9	2.4	3.3	4.1	4.9	5.6	5.9	6.2	6.5	6.8	7.1	7.4	7.6	7.9	8.2	8.4	8.7	9.0
50%	0.3	0.6	0.9	2.8	3.8	4.8	5.8	6.7	7.0	7.4	7.8	8.1	8.5	8.8	9.1	9.4	9.7	10.1	10.4	10.8
Total- Fixed O&M Cost ($ million)																				
	2018	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
0%	0.6	1.0	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
15%	0.6	1.0	1.4	1.5	1.5	1.6	1.7	1.7	1.8	1.9	2.0	2.1	2.2	2.2	2.3	2.4	2.5	2.5	2.6	2.7
20%	0.6	1.0	1.4	1.7	1.9	2.0	2.2	2.4	2.5	2.6	2.7	2.9	3.0	3.1	3.2	3.3	3.4	3.5	3.6	3.8
25%	0.6	1.0	1.4	1.9	2.2	2.5	2.8	3.1	3.3	3.4	3.6	3.7	3.9	4.0	4.2	4.3	4.5	4.6	4.8	4.9
30%	0.6	1.0	1.4	2.1	2.6	3.0	3.5	3.9	4.1	4.3	4.5	4.7	4.9	5.1	5.2	5.4	5.6	5.8	6.0	6.2
35%	0.6	1.0	1.4	2.4	3.0	3.6	4.2	4.7	5.0	5.2	5.5	5.7	6.0	6.2	6.4	6.6	6.8	7.1	7.3	7.6
40%	0.6	1.0	1.4	2.6	3.4	4.2	4.9	5.6	5.9	6.2	6.5	6.8	7.1	7.4	7.6	7.9	8.1	8.4	8.7	9.0
45%	0.6	1.0	1.4	2.9	3.9	4.8	5.7	6.6	7.0	7.3	7.6	8.0	8.4	8.6	8.9	9.3	9.6	9.9	10.2	10.6
50%	0.6	1.0	1.4	3.2	4.4	5.5	6.6	7.7	8.0	8.4	8.8	9.3	9.7	10.0	10.4	10.7	11.1	11.5	11.9	12.3
Distribution Network Augmentation Cost (%)																				
	2018	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
Rooftop Solar PV System	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%

Ground Mounted Solar PV System	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Rooftop Solar PV System Distribution Network Augmentation Cost ($ million)																				
	2018	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
0%	0.56	0.39	0.37	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
15%	0.56	0.39	0.37	0.12	0.10	0.10	0.09	0.10	0.12	0.12	0.12	0.12	0.12	0.10	0.11	0.11	0.11	0.12	0.12	0.12
20%	0.56	0.39	0.37	0.12	0.24	0.23	0.22	0.22	0.15	0.15	0.15	0.15	0.15	0.12	0.13	0.13	0.14	0.14	0.15	0.16
25%	0.56	0.39	0.37	0.09	0.36	0.35	0.33	0.32	0.17	0.17	0.18	0.17	0.18	0.14	0.15	0.15	0.16	0.16	0.17	0.18
30%	0.56	0.39	0.37	0.03	0.45	0.43	0.42	0.41	0.18	0.19	0.19	0.19	0.19	0.16	0.16	0.17	0.17	0.18	0.19	0.19
35%	0.56	0.39	0.37	-0.05	0.52	0.50	0.48	0.46	0.19	0.20	0.20	0.20	0.20	0.16	0.17	0.18	0.18	0.19	0.20	0.21
40%	0.56	0.39	0.37	-0.16	0.56	0.54	0.52	0.50	0.20	0.20	0.20	0.20	0.20	0.17	0.17	0.18	0.18	0.19	0.20	0.21
45%	0.56	0.39	0.37	-0.29	0.57	0.55	0.53	0.52	0.19	0.20	0.20	0.20	0.20	0.17	0.17	0.17	0.18	0.19	0.20	0.21
50%	0.56	0.39	0.37	-0.45	0.57	0.55	0.53	0.50	0.19	0.19	0.19	0.19	0.19	0.16	0.16	0.17	0.17	0.18	0.19	0.20
Fuel Cost ($ million)																				
	2018	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
0%	423.4	451.2	445.9	476.7	510.1	486.2	487.6	465.1	516.3	580.5	534.6	596.4	658.2	717.8	702.8	758.4	820.5	801.0	878.8	944.2
15%	423.4	451.2	445.9	472.2	500.5	479.4	479.7	451.4	506.2	566.1	515.1	570.7	633.0	697.9	666.6	717.2	772.2	762.5	823.2	879.7
20%	423.4	451.2	445.9	472.0	499.2	468.6	461.9	433.8	490.1	545.4	510.2	551.0	613.5	668.7	647.8	697.3	749.2	727.4	814.3	862.0
25%	423.4	451.2	445.9	467.0	491.7	457.5	445.5	435.2	473.3	531.9	506.8	543.0	590.3	649.5	623.5	667.2	735.7	719.6	775.4	832.7
30%	423.4	451.2	445.9	461.8	480.5	444.1	439.2	425.6	466.2	521.3	499.6	542.0	584.5	628.5	608.2	648.9	704.0	705.4	748.5	807.2
35%	423.4	451.2	445.9	459.2	468.0	436.1	429.7	413.8	463.0	503.3	496.6	531.9	573.7	622.0	600.9	635.7	684.9	694.5	738.6	777.2
40%	423.4	451.2	445.9	452.5	457.8	435.1	421.3	413.4	453.1	499.5	498.0	537.3	571.8	618.9	600.8	640.3	680.2	698.8	736.1	751.7

45%	423.4	451.2	445.9	447.0	450.7	421.7	410.9	408.1	456.5	502.0	493.1	546.0	568.0	609.0	609.4	638.4	670.7	677.3	727.5	746.3
50%	423.4	451.2	445.9	443.2	445.6	412.7	404.0	401.0	452.9	500.3	488.3	533.1	577.3	612.4	589.6	634.7	668.3	674.6	719.6	752.9
Variable O&M Cost - Financial ($ million)																				
	2018	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
0%	54.1	51.9	32.8	34.7	36.9	42.3	49.3	58.0	63.7	68.4	80.6	85.4	89.8	94.9	106.1	116.4	121.7	128.8	135.1	139.9
15%	54.1	51.9	32.8	34.4	36.3	42.0	48.9	56.9	62.5	67.1	79.3	83.4	87.7	92.1	104.5	113.1	117.9	125.9	132.0	136.7
20%	54.1	51.9	32.8	34.2	36.0	41.2	47.7	56.5	60.8	65.0	76.8	81.6	85.6	90.2	102.1	110.5	116.2	123.5	128.0	133.5
25%	54.1	51.9	32.8	33.9	35.4	40.2	46.8	53.7	59.4	63.2	74.6	79.3	84.0	88.1	99.7	107.7	113.2	120.7	126.6	131.0
30%	54.1	51.9	32.8	33.6	34.7	39.3	45.2	52.2	57.6	61.4	72.4	77.4	81.3	85.7	97.3	105.7	110.4	117.4	124.0	128.6
35%	54.1	51.9	32.8	33.2	33.8	38.6	44.8	50.5	55.9	60.0	69.6	75.2	79.2	83.5	95.3	103.5	107.9	113.8	120.3	125.6
40%	54.1	51.9	32.8	32.8	33.0	37.9	43.2	48.4	54.1	58.2	66.3	71.9	76.6	81.0	91.5	99.9	104.9	110.0	116.8	122.6
45%	54.1	51.9	32.8	32.4	32.5	36.9	42.3	46.5	51.6	56.0	63.8	68.5	73.7	78.4	87.6	96.6	101.7	107.1	113.7	119.8
50%	54.1	51.9	32.8	32.1	32.2	36.2	41.0	44.5	49.3	53.7	60.9	66.0	70.4	74.8	85.3	93.0	98.1	103.4	109.8	114.9
Variable O&M Cost - Economical($ million)																				
	2018	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
0%	43.3	41.5	26.3	27.7	29.5	33.9	39.4	46.4	51.0	54.7	64.5	68.4	71.8	75.9	84.9	93.1	97.3	103.0	108.1	111.9
15%	43.3	41.5	26.3	27.6	29.1	33.6	39.1	45.6	50.0	53.6	63.4	66.7	70.2	73.7	83.6	90.4	94.3	100.7	105.6	109.4
20%	43.3	41.5	26.3	27.4	28.8	33.0	38.2	45.2	48.6	52.0	61.5	65.3	68.5	72.2	81.7	88.4	93.0	98.8	102.4	106.8
25%	43.3	41.5	26.3	27.1	28.3	32.2	37.5	43.0	47.5	50.6	59.7	63.4	67.2	70.5	79.8	86.2	90.5	96.6	101.3	104.8
30%	43.3	41.5	26.3	26.9	27.8	31.4	36.1	41.7	46.1	49.1	57.9	61.9	65.1	68.6	77.8	84.6	88.3	93.9	99.2	102.8
35%	43.3	41.5	26.3	26.6	27.1	30.8	35.8	40.4	44.7	48.0	55.7	60.2	63.3	66.8	76.3	82.8	86.3	91.0	96.2	100.4
40%	43.3	41.5	26.3	26.3	26.4	30.3	34.6	38.7	43.3	46.5	53.0	57.5	61.3	64.8	73.2	79.9	84.0	88.0	93.4	98.0
45%	43.3	41.5	26.3	25.9	26.0	29.5	33.9	37.2	41.3	44.8	51.0	54.8	59.0	62.7	70.1	77.3	81.4	85.7	90.9	95.9
50%	43.3	41.5	26.3	25.7	25.7	28.9	32.8	35.6	39.4	42.9	48.7	52.8	56.4	59.9	68.3	74.4	78.5	82.7	87.8	91.9

Net Benefits ($ million)																				
	2018	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
15%	0.0	0.0	0.0	-4.3	0.7	-2.0	-0.6	4.3	-0.6	3.5	8.4	15.2	14.3	11.6	26.6	32.6	39.9	28.4	45.3	53.9
20%	0.0	0.0	0.0	-24.5	-13.8	-6.1	2.9	8.4	12.2	20.9	10.1	30.9	30.3	38.1	42.7	49.9	59.3	60.8	52.1	68.5
25%	0.0	0.0	0.0	-40.4	-22.6	-10.6	4.2	-5.5	24.9	31.1	9.9	35.6	49.3	54.1	64.1	77.4	70.0	65.6	86.7	93.7
30%	0.0	0.0	0.0	-56.4	-27.7	-12.9	-4.3	-11.5	28.3	37.3	13.6	32.6	51.4	72.0	76.2	92.1	98.8	76.6	109.7	115.5
35%	0.0	0.0	0.0	-76.1	-32.6	-22.0	-11.8	-14.5	27.5	50.8	12.8	38.3	58.0	75.4	80.1	101.4	114.1	84.8	116.4	141.2
40%	0.0	0.0	0.0	-91.9	-40.1	-38.5	-19.6	-30.6	32.8	50.2	8.4	29.5	55.6	74.9	77.6	94.1	115.4	77.0	115.5	162.5
45%	0.0	0.0	0.0	-110.1	-52.2	-43.3	-27.1	-41.2	25.6	43.2	8.7	17.2	55.1	81.2	66.4	92.8	121.3	94.5	119.7	163.2
50%	0.0	0.0	0.0	-130.7	-67.0	-53.5	-38.4	-50.6	24.5	40.8	9.1	25.5	41.3	75.0	81.9	93.2	119.9	93.5	124.0	152.9