FINAL REPORT

ON

"Study and Analysis of Optimal Distributed Generation for Access to Grid Electricity for All in Five Years with Participation from Local-level Government"

Submitted To:

National Planning Commission

Singhadurbar, Kathmandu

Submitted By:

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LIST OF ACRONYMS

AC	Alternating Current
ADB	Asian Development Bank
AEPC	Alternative Energy Promotion Center
AGE4ALL	Access to Grid Electricity for ALL
BAT	Best Available Technology
BS	*Bikram Sambat*
CBS	Central Bureau of Statistics
CUF	Capacity Utilization Factor
CUEG	Community Electrification Users Group
DC	Direct Current
DG	Distributed Generation
DHM	Department of Hydrology and Meteorology
DOED	Department of Electricity Development
DSCR	Debt Service Coverage Ratio
EIRR	Economic Internal Rate of Return
GDC	Geographic and Demographic Center
GHG	Green House Gasses
GIS	Geographical Information System
GON	Government Of Nepal
ICT	Information and Communication Technology
INPS	Integrated Nepal Power System
Kg	Kilogram
kV	KiloVolt
kW	KiloWatt
kWh	Kilowatt Hour
kWp	KiloWatt Peak
LBOE	Levelized Benefit of Electricity
LCOE	Levelized Cost of Electricity
MS	Microsoft
MTF	Multi-Tier Framework
NEA	Nepal Electricity Authority
NEAEC	Nepal Electricity Authority Engineering Company
NPC	National Planning Commission
NPV	Net Present Value
O&M	Operation and Maintenance
PLF	Plant Load Factor
PV	Photovoltaic
PR	Performance Ratio

RE	Renewable Energy
RET	Renewable Energy Technology
ROE	Return on Equity
ROE	Return on Equity
SDG	Sustainable Development Goal
SE4ALL	Sustainable Energy for All
SLD	Single Line Diagram
SSE	Surface meteorology and Solar Energy
SUDIGGA	Sustainable Distributed Generation and Grid Access to All
SWERA	Solar and Wind Energy Resource Assessment
T&D	Transmission & Distribution
TM	Town Municipality
UN	United Nations
VAT	Value Added Tax
VM	Village Municipality
WECS	Water and Energy Commission Secretariat

ACKNOWLEDGEMENT

It is a matter of honor and privilege to carry out this study and design work for the apex planning body of the country, National Planning Commission (NPC). The work entitled “The Study and Analysis of Optimal Distributed Generation for Access to Grid Electricity for All in Five Years with Participation from Local Level Governments” is an opportunity to contribute towards nation-building from the energy sector.

We are grateful to Honorable Vice Chairperson of NPC, Dr. Swornim Wagle and Honorable Member of NPC, Dr. Arbind Mishra for keeping faith with a start-up company that had only the ideas and a conviction of thought, and a commitment to fulfill obligations with all efforts at its command. A philosophy and a concept born from the experiences in the remote micro-hydro and isolated small hydro-power plants of Nepal, and from the insights gained from the efforts of interconnecting micro-hydro plants in a mini-grid as well as connecting to National grid, and having closely felt the pain of the prolonged wait of the rural Nepal for electricity in modern times, all of this had gone into proposing the study concept to National Planning Commission which ultimately conceived the present Project. We are so much more grateful to Dr Wagle and Dr Mishra in seeing the merit of this proposal and finally adopting and implementing the study.

Continued support during the exploratory research and study as well as design phase from honorable Dr. Arbind Mishra has been invaluable to our whole team. We are also very thankful to the energy program directors and high officials of NPC who supported us all through the study and believed in the outcome that was to be.

We would like to thank the experts from energy sector who provided during a workshop interaction very important critique to the methodologies of identifying the hydro and solar projects in distributed manner. Valuable support from Nepal Electricity Authority (NEA) was also made available to us towards data collection regarding the distribution lines and substations as well as providing expert manpower to support our efforts. Alternative Energy Promotion Center (AEPC) also provided very valuable support during the field consultations as well as providing expertise in the solar projects design. We acknowledge with thanks the contribution from Mr Sunil Kumar Dhungel, NEA, and Mr Jiwan K Mallik, AEPC, as well as the expert comments from officials from Ministry of Energy, and Water and Energy Commission Secretariat (WECS).

We cannot remain without acknowledging with thanks the diligent efforts put by our own team, namely, Deepak Das Tamrakar, Khimananda Kandel, Gopal Basnet, Sitaram Neupane, Bhaskar Kafle and the Hydropower Team, Abhishek Yadav, Dipesh Shrestha and the Solar Team, Kalidas Neupane and the Biomass Team, Prajjwal Khadka, Baburaja Maharjan and the Electrical Team and the entire office support team in helping to accomplish this objective. Special thanks are also due to Abhyaan company which joined hands with our effort in hydro-project identification in Nepalese rivers by developing a web-based application that will help engineers in this sector all over Nepal. We acknowledge the efforts of Dr Netra Timilsena in preparing R-based open source application that again helps to find river discharges based on DHM data. We also would like to

express many thanks to Khimananda Kandel for developing a complete spread-sheet based application that helps prepare a desk-study report from a given set of inputs; the result of such an application made the compilation of such vast projects possible in a short period. We would also like to thank Abhishek Yadav for developing the Financial and Economic Models that enabled us to select the most financially attractive projects, calculate necessary investments and government viability gap funding (VGF), and determine the economic implications of different energy development scenarios.

Furthermore, we sincerely hope that the present study will meet NPC's objective for "Optimal Distributed Generation for Access to Grid Electricity for All in five years with participation from Local Level Government".

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1 EXECUTIVE SUMMARY

1.1 INTRODUCTION

This Final report presents the findings of the "Study and Analysis of Optimal Distributed Generation for Access to Grid Electricity for All in Five Years with Participation from Local-level Government" project. This project studies the optimal Distributed Generation (DG) development in tandem with an optimized Transmission and Distribution (T&D) network extension pathway to provide access to electricity in all 753 municipalities of Nepal. Access to electricity has manifold economic benefits. Electricity reduces human drudgery, enhances comfort, and enables safer and cleaner environment. It boosts productivity and economic activity, creates jobs, and facilitates delivery of education, health and government services. It is thus natural that the United Nations (UN) led Sustainable Energy for All (SE4ALL) initiative seeks to ensure such universal access to modern energy services and a similar Sustainable Development Goal 7 (SDG7) seeks to ensure access to affordable, reliable, sustainable and modern energy for everyone by 2030. In a similar spirit and approach, National Planning Commission of Nepal has identified Sustainable Distributed Generation and Grid Access to All (SUDIGGAA) as the path towards achieving SE4ALL and SDG7.

The traditional approach to electricity generation has been to generate power through large central power plants and transmit this power to different load centers through the use of T&D network also known as the national grid. This approach often results in low cost of electricity generation; however, by the time this electricity reaches the end users located far away, the cost increases because of the additional costs and power losses incurred by the T&D network. Distributed Generation (DG) is an approach that employs small-scale technologies to produce electricity close to the end users of power. DG technologies often consist of modular renewable energy generators, which have a number of benefits such as lowering the cost of electricity, and increasing the reliability and security of power supply with fewer social and environmental consequences. Moreover, on-grid DG sources can use islanding techniques to serve the local distribution network even when the central grid is offline due to outages or load shedding.

Energy services are critical ingredients of socioeconomic development. Therefore, GoN can deliver large economic benefits to the local population as well as kick-start the local economy by expanding the T&D network till the geo-emographic center of each municipality . This exgtension works, although capital intensive, will also increase the sustainability of Distributed Generation (DG) plants. The Government, by appropriately subsidizing the development of Distributed Generation (DG) resources, can make it attractive for investment by local bodies and cooperatives who are eligible for government grant, The central grid can enable higher level of power and energy consumption by the local economy, which could qualify as the highest level of household electricity access according to the Multi-tier Framework (MTF). T&D network extension, which entails development of T&D lines, hubs, and substations to reach the Geographic and Demographic Centre (GDC) of Municipalities, alongside the development of DG projects, can decrease T&D losses and increase the reliability of the power system. The GDC locates the point within a Municipality that is the best location to build a Substation to service all customers within the Municipality cost-effectively.

This concept of 'Sustainable Distributed Generation and Grid Access to All' (SuDiGGAA) can act as a guiding principle for local governments to optimally utilize subsidies and scarce resources. SUDIGGAA has the potential to be a catalyst to electrify all municipalities within the municipality and economically exploit the local energy resources. SUDIGGAA has many other benefits. Hydropower DG plants can reduce Capital and Operational expenditure of Transmission and Distribution networks. Solar PV plants provide reactive support to the grid and decrease reactive losses. They can service local loads and further reduce transmission losses of the grid. Additionally, Solar energy provides the energy mix in the national grid which increases energy security while providing complementarity to seasonal variation of hydro-power generation. Moreover, DG development and T&D extension can have ripple economic effect through forward and backward economic linkages.

The concept of Distributed Generation (DG) in each municipality advocates the Bottom-Up approach of Grid-expansion planning. By identifying the best source of energy available locally considering the local population distribution and means of production, it also ensures participation of the local government decision making. While the identified generation project needs to be within an economic distance from the designated location for an interconnecting substation, it also provides the vector for Grid Expansion from the local end.

From a preliminary examination of the renewable energy resources available for electricity generation in the municipalities, it is evident that most of them have one or more renewable sources such as mini-hydro, solar, wind, or biomass available for development within their area, provided that the grid is available to balance the power by exporting the surplus and importing the deficit energy. Therefore, DG development can be integrated with the Top-Down approach of T&D network extension from existing reaches of national grid to all the DG sources. This combination of Top-Down and Bottom-Up approaches will enable the expanding network to reach to all the municipalities of Nepal as well as provide the local means of income through Distributed Generation while comparatively reducing the demand on the central grid to completely supply all these areas.

With this in mind, the overall objectives of this study were to:

- Study all the 753 Municipalities and identify the optimum extension path of the T&D network to increase access to energy as well as integrate the proposed DG plants
- Find small-scale renewable sources of electricity generation in these municipalities that can be developed and operated in a sustainable manner with access to the grid
- Explore the economic and financial aspects of DG development and Grid extension including Viability Gap Funding (VGF) determination

- Prepare a Workable Plan for Sustainable Distributed Generation for Grid Access to All (SUDIGGAA)

The overall methodology is illustrated in Figure below.

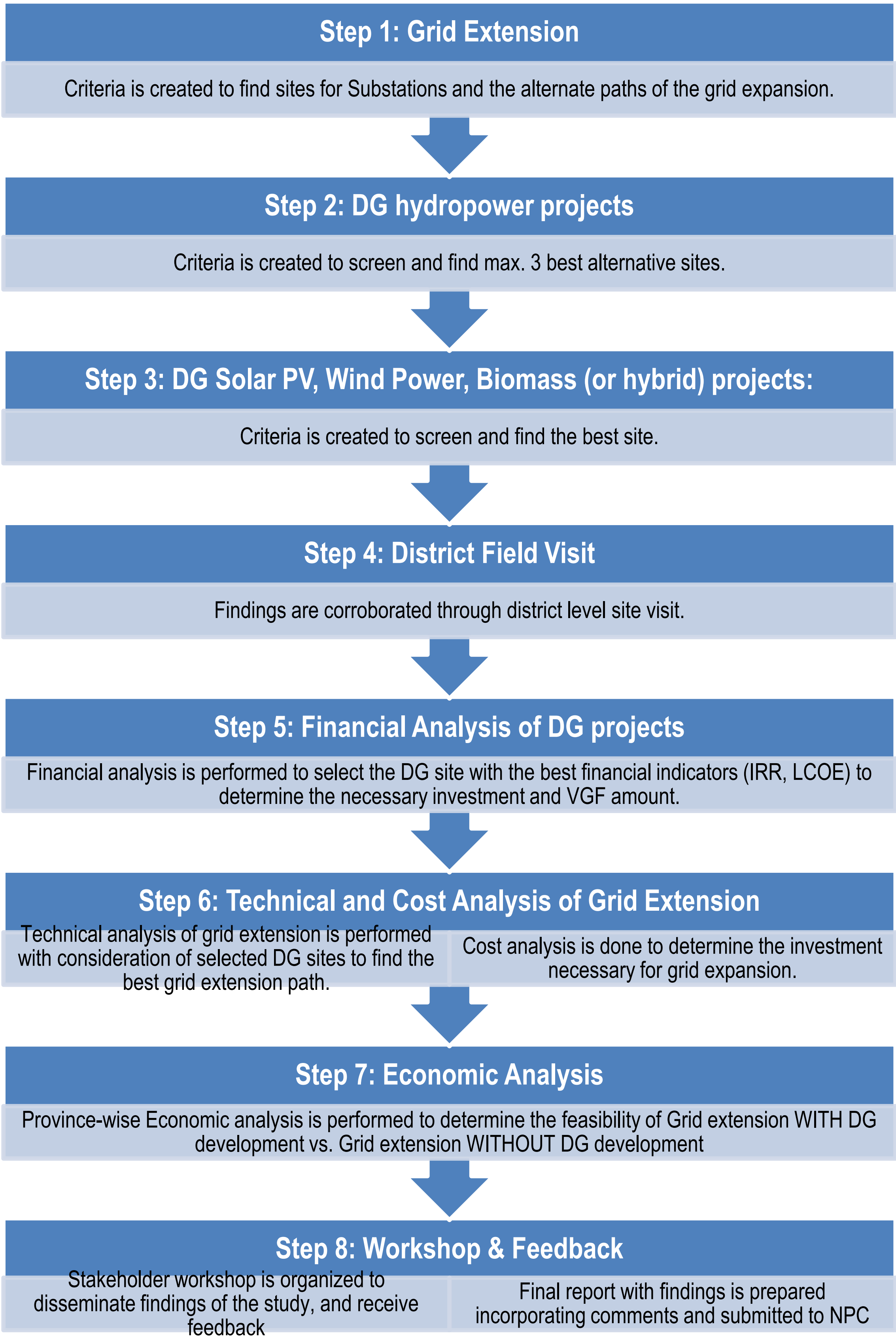

Figure 1 : Overall methodology of the project

1.2 FINDINGS

1.2.1 Hydropower

The study shows that there is a potential of hydropower ranging from 500 kW to 1000 kW in 277 Local Bodies with total identified sites (maximum 3 no. of sites taken in this study) are 456. Total power potential is found to be 383.56 MW. The hydrological analysis shows that the discharge is relatively higher in the eastern region and goes on decreasing in western region. The study has been limited in the exploration of hydropower to a range of project size larger than 500kW from sustainability criteria and up to 1000kW from the local government's executive jurisdiction criteria.

The present study is made based on the available data, information and analysis tools for finding the discharge. Topographical maps and digital maps are used for finding the measurement. So, flow verification of the identified sites have been proposed and need to carry out different stages of consulting study before the implementation of the projects. Moreover, the analysis for hydropower does not consider the cost of land, which might be significant in some areas. The present study also needs to be verified geologically and some sites might be rejected with geological requirements.

Table A: Province wise Summary of Identified Hydropower Sites

S.N.	Province	No. of Local Bodies	No. of Sites Identified	Power (MW)
1	Province 1	56	84	66.11
2	Province 2	-	-	-
3	Province 3	53	81	64.44
4	Province 4	29	54	45.14
5	Province 5	23	38	26.995
6	Province 6	60	102	94.759
7	Province 7	56	97	86.119
Total		**277**	**456**	**383.56**

1.2.1.1 Financial Analysis of Hydropower at different Costs

Financial Analysis is performed for 1 MW Hydropower Plant to get a better understanding of financial indicators and VGF required for a range of Capital Costs with the same revenue of NPR 6/kWh NEA PPA Rate with 8 simple escalations of 3% each. NPR 6/kWH is the annual average tariff at the beginning of operation considering the present dry season, six months, tariff of NR 8.40 and the wet season, six months, tariff of NR 4.80 for a Q65 design criteria. The range of costs have been selected to represent the minimum and maximum cost of the Hydropower Projects selected through this study. The results are presented in Table B.

Table B : Financial Analysis of Hydropower (1000 kW) at different Costs

COST / OUTPUT	Cost I	Cost II	Cost III	Cost IV	Cost V	Cost VI	Cost VII
	Capital Cost* [NPR/ kW] = 162,528	**Capital Cost [NPR/ kW] = 200,000**	**Capital Cost [NPR/ kW] = 235,000**	**Capital Cost [NPR/ kW] = 300,000**	**Capital Cost [NPR/ kW] = 400,000**	**Capital Cost [NPR/ kW] = 500,000**	**Capital Cost [NPR/ kW] = 579,475**
LCOE [NPR/kWh]	3.95	4.86	5.71	7.29	9.72	12.15	14.09
LBOE [NPR/kWh]	7	7	7	7	7	7	7
ROE [%]	30.85%	20.93%	15.07%	8.33%	2.30%	-1.65%	-4.11%
NPV [NPR-Million]	136.78	93.29	52.66	-22.77	-138.84	-254.91	-347.15
Cost Benefit Ratio	3.81	2.55	1.75	0.75	-0.16	-0.70	-1.00
Pay Back Period [Years]	3.75	6.15	9.56	14.70	21.02	>25	>25
VGF required per kW [NPR/ kW]**	None	None	0	79,000	201,000	323,000	420,000
First Year PPA Rate* required [NPR/ kWh]**	4.16	5.12	6.00	7.67	10.22	12.77	14.81

NOTES:

* O&M Costs changes as well because Yearly O&M Costs is calculated as 3% of Capital Cost

** To achieve at least 15% ROE (criteria for financial viability)

*** With 8 simple escalations of 3% each to achieve 15% ROE in case of No VGF provided

As can be seen from the Table B, for the case of 1 MW Hydropower Plant with 65% PLF, the range of Capital Cost per kW has significant effects on the financial attractiveness of the project. For Capital Costs from NPR 162,528 to 235,000 per kW (Costs I, II & III), the ROE is above 15% and no VGF is required at the current PPA Rate (NPR 6/ kWh). For projects with Capital Costs from NPR 235,000 to 300,000 per kW (Cost IV), the VGF required is less than NPR

80,000/kW. Beyond Capital Costs of NPR 317,000/kW (Cost V, VI, VII), the VGF required increases beyond 100,000/kW.

1.2.2 Solar

1.2.2.1 Solar PV With Battery

Table C : Sensitivity Analysis of Scenario A (1 MWac Solar PV With 500 kWh Battery Backup)

CASE / OUTPUT	Base Case	Case I	Case II	Case III	Case IV	Case V
	Capital Cost* [NPR/ kW] = 164,661	**Capital Cost [NPR/ kW] = 140,000**	**Capital Cost [NPR/ kW] = 120,000**	**Capital Cost [NPR/ kW] = 100,000**	**Capital Cost [NPR/ kW] = 80,000**	**Capital Cost [NPR/ kW] = 60,000**
LCOE [NPR/kWh]	14.02	11.93	10.25	8.56	6.87	5.18
LBOE [NPR/kWh]	6.98	6.98	6.98	6.98	6.98	6.98
ROE [%]	-3.22%	-0.84%	1.60%	4.86%	9.67%	18.25%
NPV [NPR-Million]	-89.38	-63.67	-42.81	-21.95	-1.09	19.75
Cost Benefit Ratio	-0.81	-0.52	-0.19	0.27	0.95	2.10
Pay Back Period [Years]	>25 years	>25 years	22.07	17.81	13.96	6.88
VGF required per kW [NPR/ kW]**	110,000	83,000	61,000	38,000	16,000	None
First Year PPA Rate* required [NPR/ kWh]**	14.85	12.63	10.86	9.04	7.27	5.47

NOTES:

* O&M Costs decrease as well because Yearly O&M Costs is calculated as 1.5% of Capital Cost

** To achieve at least 15% ROE (criteria for financial viability)

*** With 8 simple escalations of 3% each to achieve 15% ROE in case of No VGF provided

For the Base Case of 1 MWac Solar Plant with 500 kWh Battery Storage, the LCOE is quite high at NPR 11.96, 12.16, 12.56, 13.25, and 14.02 per kWh for Region E, F, D, C, A and B respectively. Highest LCOE is for Region B (East Hills) due to lowest CUF of 17.00% for this region and lowest LCOE is for Region E (Remote West Hills) followed by Region F (Very Remote West Hills). The high CUF of Regions E and F compensates for the higher Capital Costs of these regions (due to higher transport costs) to result in most cost effective solutions in these regions. Nonetheless, the Viability Gap Funding (VGF) required for each Region is high around NPR 100,000/kWac. Without VGF, the NEA PPA Rate with 8 no. of 3% escalations required for 15% ROE would be around NPR 14.85/ kWh. Further, if only 200 kWh of battery storage is considered for Region A, the Capital Costs will decrease to around NPR 140,000/kWac, which will result in lower VGF of NPR 83,000/kWac.

Sensitivity Analysis shows that if the Capital Costs decrease to NPR 120,000/ kWac within 5 years, the LCOE for Region A (East Terai) will decrease from NPR 14.02 to 10.25 per kWh with ROE of 1.60%, which will require lesser Viability Gap Funding (VGF) of NPR 61,000 per kW. If the Capital Costs of Solar PV with 500 kWh Battery Storage decrease to the range of NPR 60,000 per kWac within 5 to 10 years, the Plant will require no VGF as the LCOE will decrease to about NPR 5.18/ kWh and the LBOE of NPR 6.98/kWh (i.e. NEA PPA Rate of NPR 6/kWh with 8 no. of 3% escalations) will be enough to generate ROE of 18%. However, such drastic decrease in costs for Solar PV with Battery Storage is not possible immediately. Nonetheless, advancements in bi-directional inverter and battery technology could result in lower Capital Costs over time.

1.2.2.2 Solar PV without Battery

Table D : Sensitivity Analysis of Scenario B (1 MWac Solar PV Without Battery Backup)

CASE / OUTPUT	Base Case	Case I	Case II	Case III
	Capital Cost* [NPR/ kW] = 120,211	**Capital Cost [NPR/ kW] = 100,000**	**Capital Cost [NPR/ kW] = 80,000**	**Capital Cost [NPR/ kW] = 60,000**
LCOE [NPR/kWh]	10.15	8.44	6.75	5.06
LBOE [NPR/kWh]	6.98	6.98	6.98	6.98
ROE [%]	1.90%	5.23%	10.10%	18.70%
NPV [NPR-Million]	-41.59	-20.52	0.335	21.19

Cost Benefit Ratio	-0.15	0.32	1.01	2.18
Pay Back Period [Years]	21.53	17.26	13.44	6.88
VGF required per kW [NPR/ kW]**	60,000	36,000	15,000	None
First Year PPA Rate* required [NPR/ kWh]**	10.79	8.96	7.18	5.39

NOTES:

* O&M Costs decrease as well because Yearly O&M Costs is calculated as 1.5% of Capital Cost

** To achieve 15% ROE at the given PPA Rate

*** With 8 simple escalations of 3% each to achieve 15% ROE in case of No VGF provided

For the Base Case of alternative Scenario in which 1 MWac Solar Plant without Battery Storage is considered, the LCOE of Region A (East Terai) decreases substantially from NPR 14.02 to NPR 10.15 per kWh. Nonetheless, the Viability Gap Funding (VGF) of NPR 60,000/kWac is still necessary for ensuring 15% ROE. Without VGF, the NEA PPA Rate with 8 no. of 3% escalations required for 15% ROE would be around NPR 10.79/ kWh.

Sensitivity Analysis shows that if the Capital Costs of Solar PV without any battery decreases to NPR 100,000/ kWac within a few years, the LCOE for Region A will decrease from NPR 10.15 to 8.44 per kWh with ROE of 5.23%, which will require lesser Viability Gap Funding (VGF) of NPR 36,000 per kW. If the Capital Costs of Solar PV without Battery Storage decrease to the range of NPR 60,000 per kWac within 5 years, the Plant will require no VGF as the LCOE will decrease to about NPR 5.06/ kWh and the LBOE of NPR 6.98/kWh (i.e. NEA PPA Rate of NPR 6/kWh with 8 no. of 3% escalations) will be enough to generate ROE of 18%. However, such drastic decrease in costs for Solar PV is not possible immediately. Apart from the decrease in costs in the international market, the Capital Cost can be decreased through substantial policy interventions such as additional exemptions on tax, custom duty and excise duty.

Nonetheless, within the scope of this study, it would be unfair to compare Solar PV without any battery storage to Hydropower and Biomass technologies, as the Solar PV would not be able to supply any electricity during nights in the event the central grid is down, thus compromising on the aspect of reliability of supply. Nonetheless, Solar PV with Battery could be developed in two phases, such that Solar PV Plant without Battery but with adequate space for adding batteries and inverters later is developed in the first phase, and additional Inverter and Battery necessary is added in the subsequent phases. This will help to break the Total Investments and VGF into multiple phases while providing the flexibility of achieving increasing level of reliability from the project over time.

1.2.3 Grid Extension

1.2.3.1 Number and Type of Substations and T&D Lines

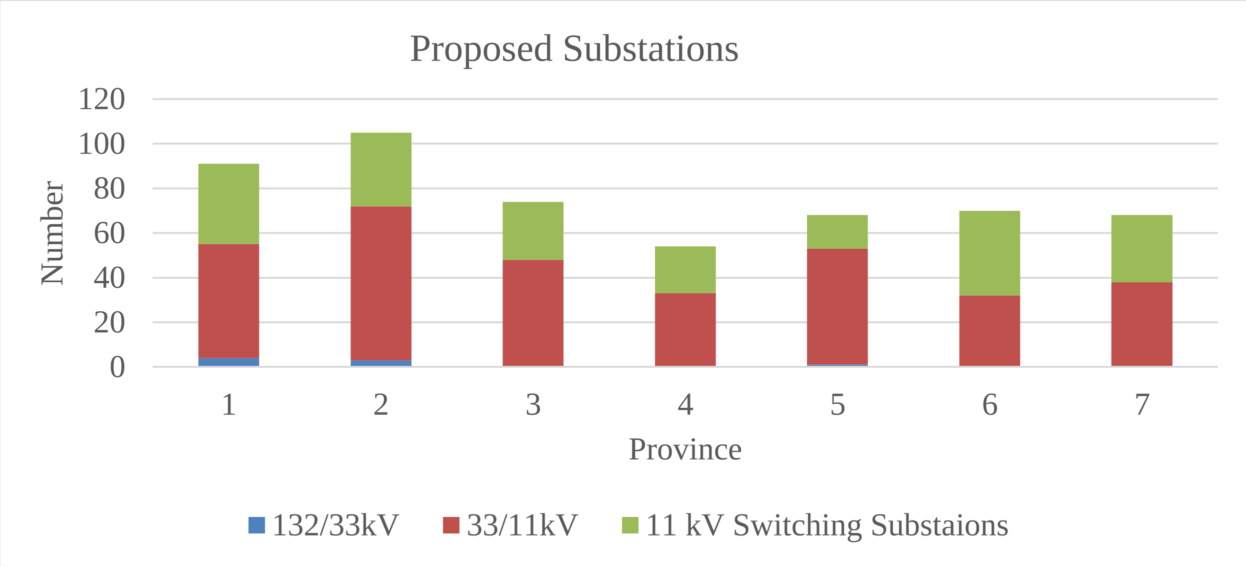

Figure 2 : Number of Proposed Substations

Figure above shows the number of Substations required by Substation type for each Province. It was found that generally the number of 33/11 kV SS were highest for each province, followed by 11 kV Switching SS and 132/33 kV Substations. This was expected as 33/11 kV Substation was proposed for each Municipality as a development hub, followed by 11 kV for primary distribution. In case the 33 kV double circuit lines were not enough to handle the load, 132 kV substations were proposed. 132 kV Substations were only proposed in Provinces where NEA has insufficient number of Substations.

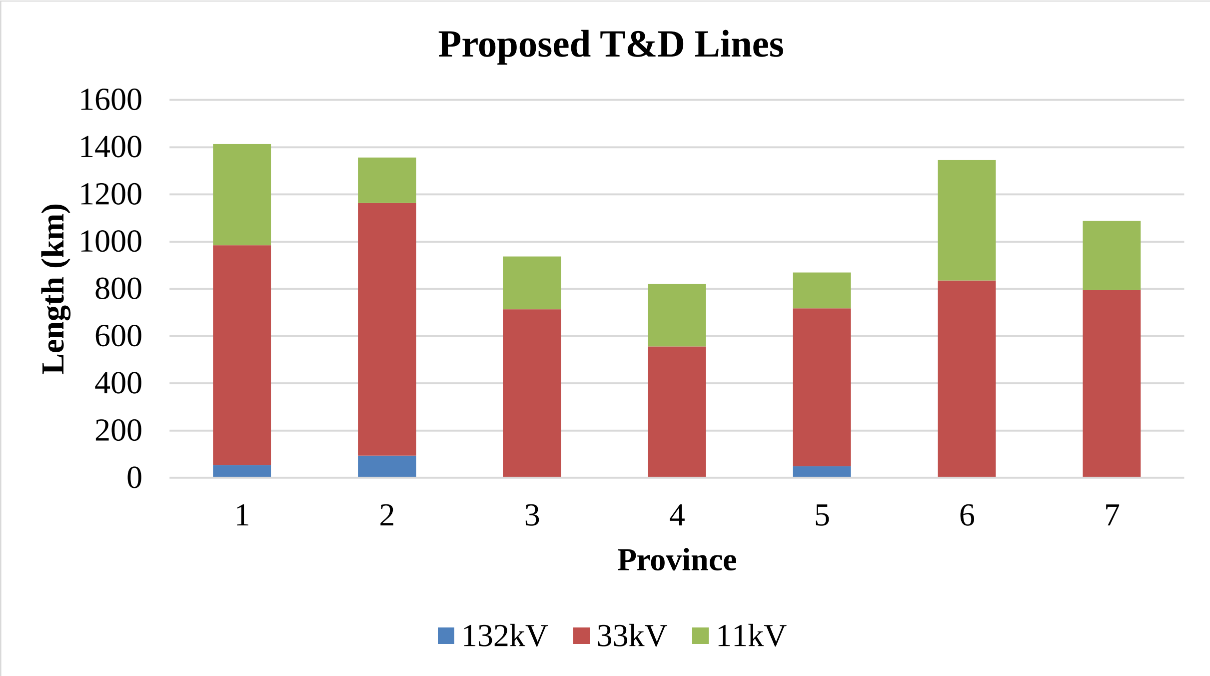

Figure 3 : Length of Proposed T&D Line Extension

Figure above shows the length of T&D network extension required by Line Voltage for each Province. It was found that the length of the 33 kV lines were highest for each province, followed by 11 kV lines and 132 kV lines. In Province 2, the length of 33 kV lines was highest among the Provinces because there were a large number of high load centers compared to other Provinces,thus requiring longer lengths of higher current carrying capacity 33 kV Lines.

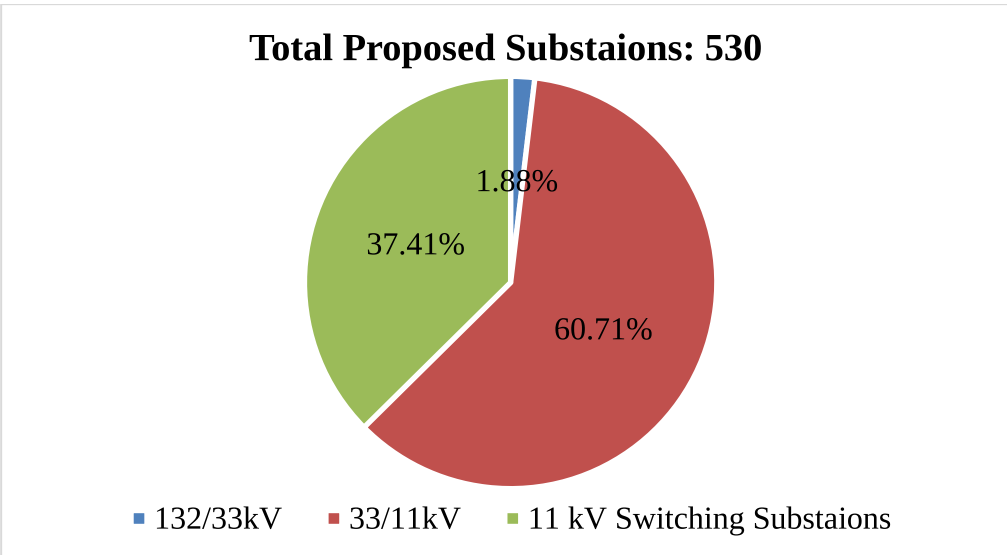

Figure 4 : Total Proposed Substation : 530

Overall, highest number of 33/11 kV Substations were proposed, followed by 11 kV Substations for primary distribution. The share of 132 kV substations were the lowest as they were considered only when 33/11 kV Substations were insufficient.

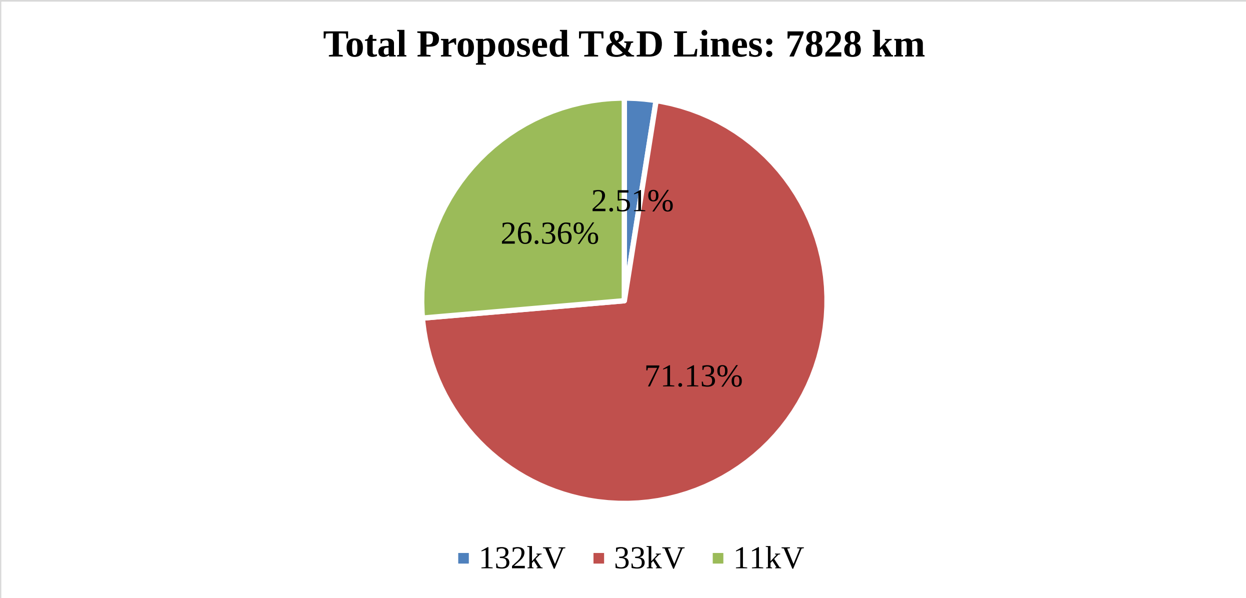

Figure 5 : Total Proposed T&D Lines

Overall, it was found that the length of the proposed 33 kV lines were highest, followed by 11 kV lines and 132 kV lines. 33 kV lines were highest because they were found to be most suitable to service the load centers. 132 kV lines were the lowest as they were only considered when even double circuit 33 kV lines were insufficient.

1.2.3.2 Cost of Substation and T&D Lines

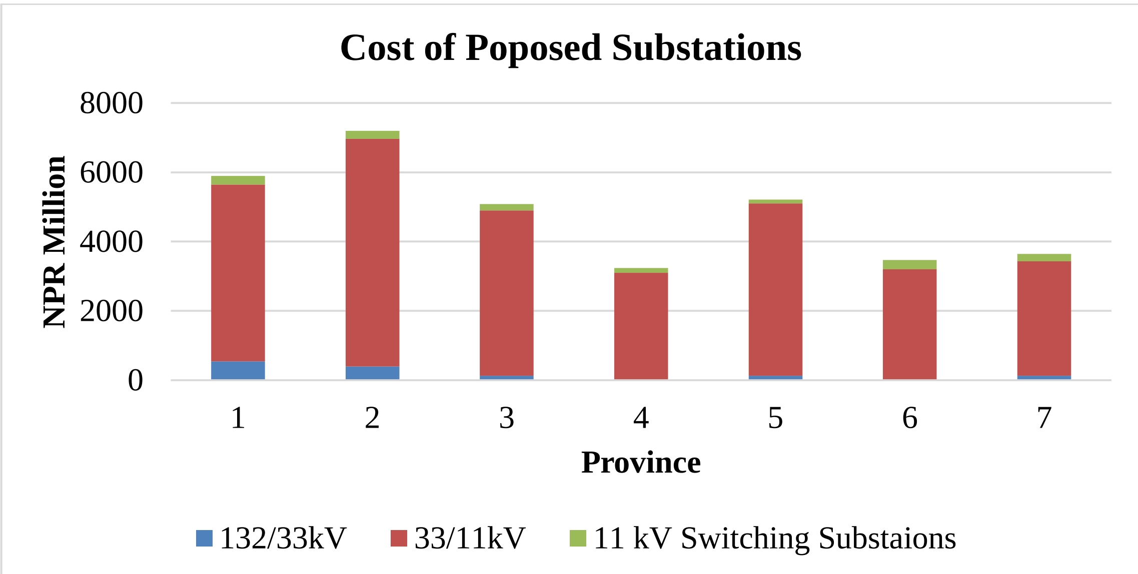

Figure 6 : Cost of Proposed Substations

Figure above shows that the Cost of 33/11 kV Substations were highest for each Province due to their greater share.

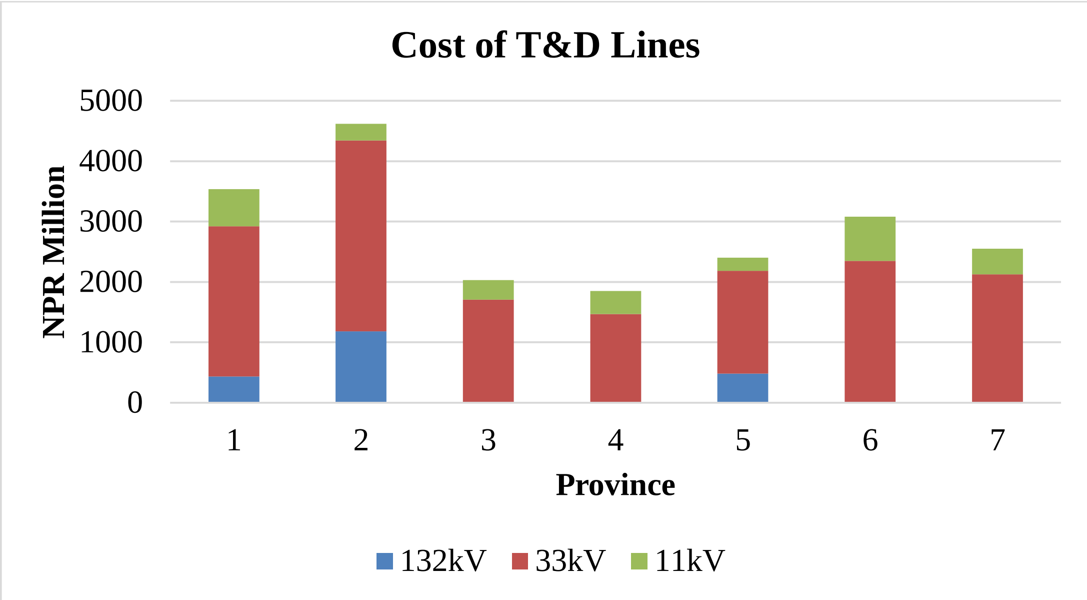

Figure 7 : Cost of Proposed T&D Lines

The cost of 33 kV lines were highest for each Province due to their greater share. In Province 2, the cost of 33 kV lines was highest among the Provinces because of larger length line required to service greater number of high load centers compared to other Provinces.

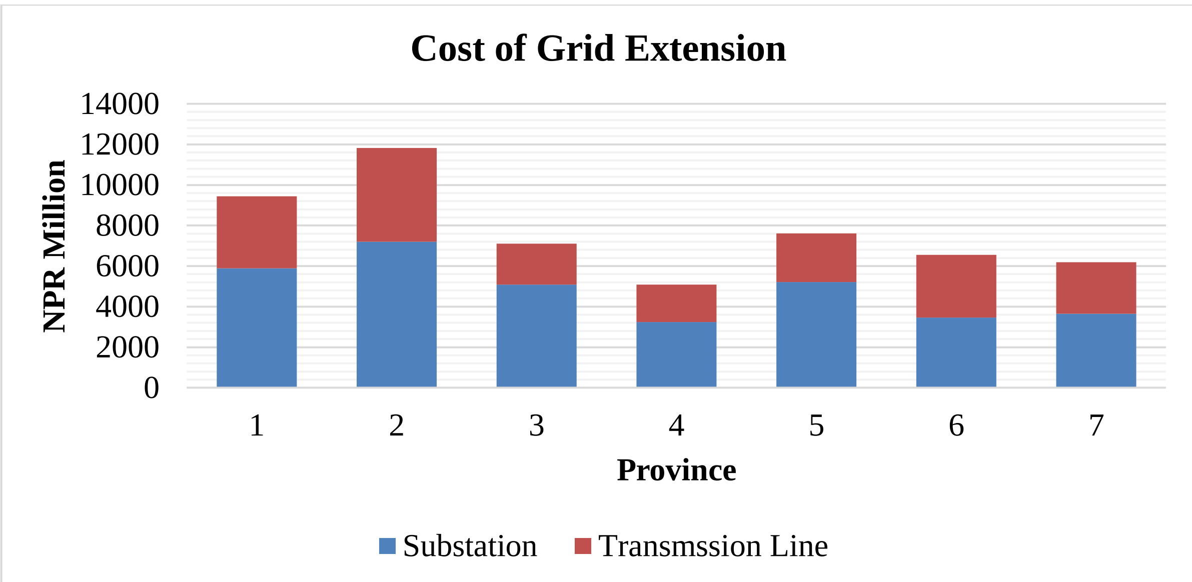

Figure 8 : Cost of Grid Extension

Figure above shows the Cost of T&D network extension (Million NPR) required for Substation and T&D lines for each Province. It was found that the overall cost was highest for Province 2 due to larger length of 33 kV lines required. Moreover, the cost of Substations was higher than that of T&D lines for each Province.

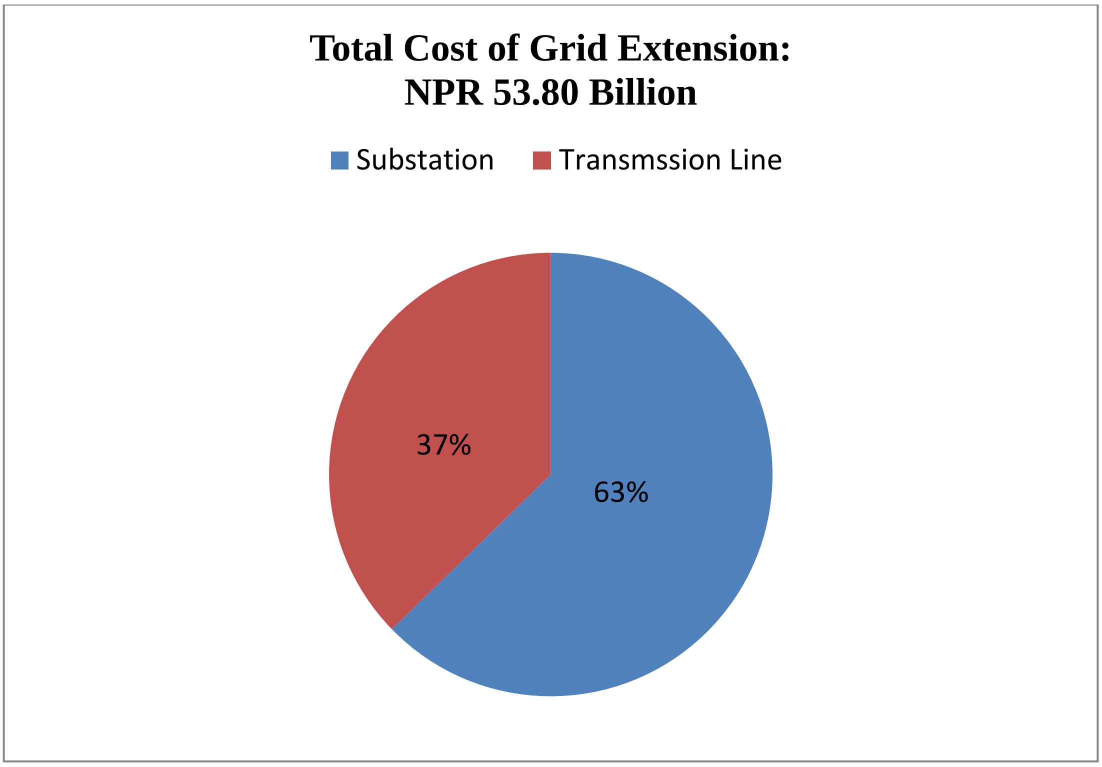

Figure 9 : Total Cost of Grid Extension

Overall, the total cost of Grid Extension was NPR 53.8 Billion, of which Substations accounted for almost 63% of the total cost due to high cost of Transformers and associated equipment used in a Substation.

1.2.4 Financial Analysis of DG Projects:

1.2.4.1 Levelized Cost and Benefit of Electricity

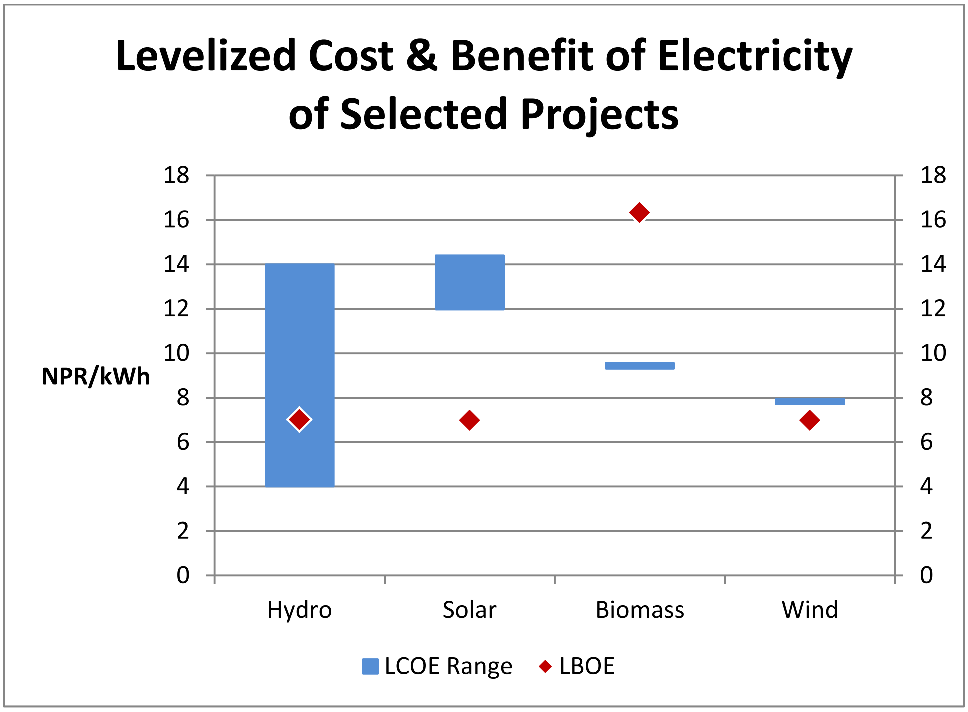

Figure 10 : Levelized cost and benefit of electricity of selectedDG projects

Financial analysis considered unique local characteristics such as hydrology, road access, capacity utilization factor, transport costs, etc.; therefore each Municipality had its own unique result. It was seen that Biomass had a Levelized cost of electricity (LCOE) of approx. NPR 9.56/ kWh and Levelized benefit of electricity (LBOE) of approx. NPR 16.32/ kWh and ROE of 29%. High plant load factor, income from sale of electricity to NEA and additional income from sale of fertilizer byproduct results in a very attractiveROE for Biomass. Nonetheless, due to scarcity of well-established waste collection system, and pilot projects for testing business models; the second ranked DG project may have to be reconsidered. For Hydropower, the selected projects had LCOE in the range of NPR 4/kWh to NPR 14/kWh, and LBOE of NPR 7/kWh. For Solar PV project with Battery, the selected projects had LCOE in the range of NPR 11.96/kWh to NPR 14.40/kWh, and LBOE of NPR 6.98/kWh. For Wind power, the LCOE was only calculated for 3 sites with on-site wind speed data (Avg. annual wind speed at 10 m height = 3.35 m to 6.5 m). It was found that the LCOE was NPR 7.95/ kWh and LBOE was NPR 6.98/kWh. The LBOE was around NPR 7/kWh for Solar PV, Wind and Hydroower as it was calculated based on the NPR 6/kWh Average NEA Tariff and 3% escalation for 8 years. For Solar, theROE ranged from -3.6 to -0.8 % and for Wind Power it was around 6%. As none of the solar or wind project could deliver ROE of 15% or greater, Viability Gap Funding (VGF) was considered for all of these projects. For Hydropower, the ROE ranged from -4 to 30%. Only those Hydropower projects with ROE less than 15% were considered for VGF. The high capital costs and low capacity utilization factor of Solar PV in comparison to other technologies resulted in the lowest range of ROE.

1.2.4.2 Number of Projects and Installed Capacity

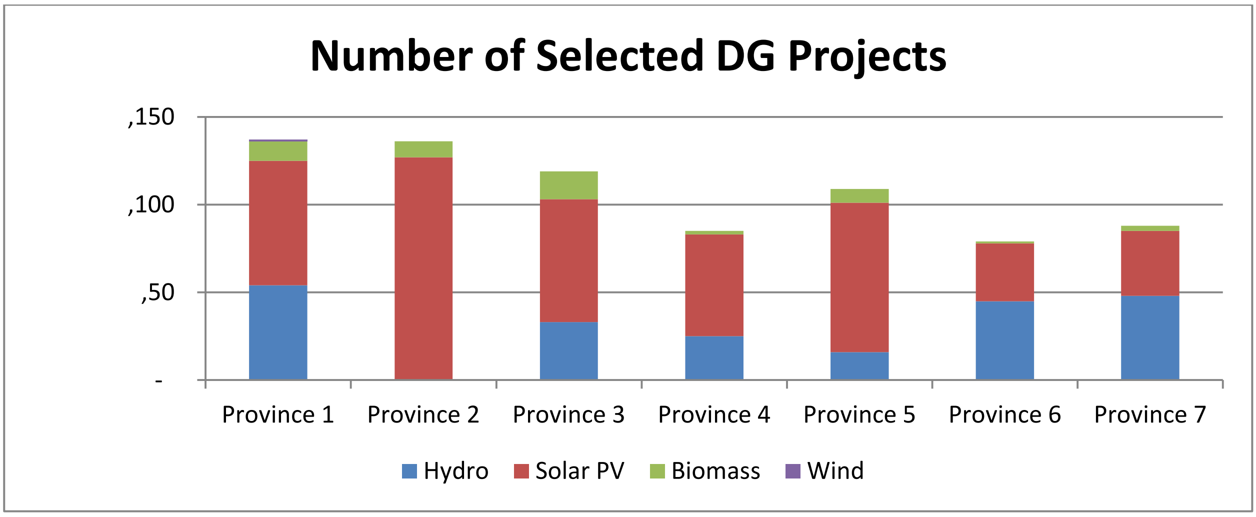

Figure 11 : Number of selected DG Projects

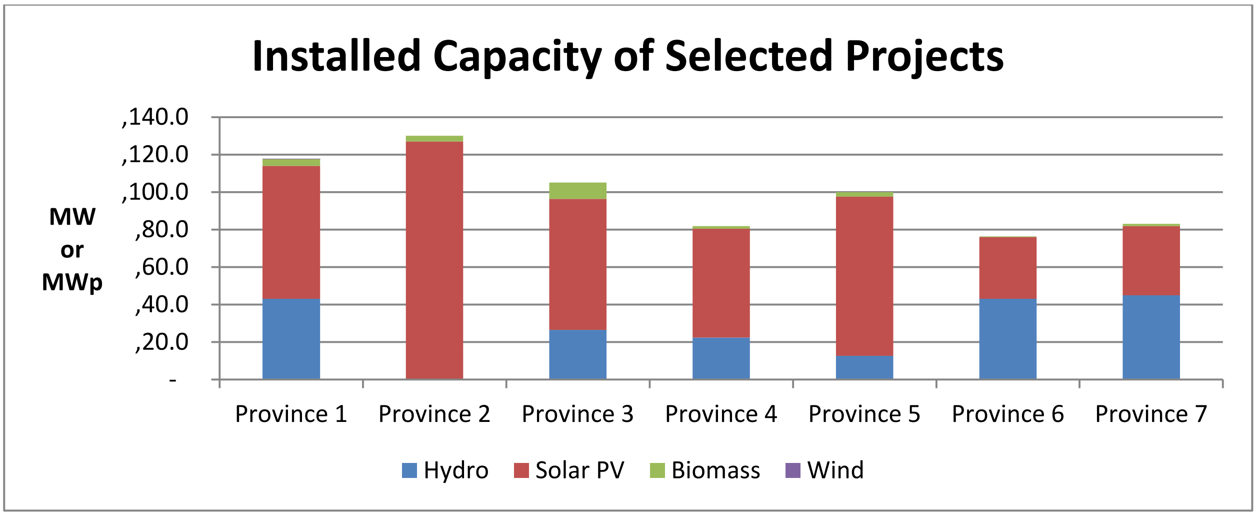

Figure 12 : Installed capacity of selected DG projects

Based on the findings of the Financial Analysis, 54 Hydropower sites with total installed capacity of 43 MW (which was the highest number of Hydropower sites selected in a Province), 71 Solar PV sites with total installed capacity of 71 MWp, 11 Biomass sites with total installed capacity of 3.5 MW and 1 Wind power site with total installed capacity of 0.2 MW were selected In Province 1. In Province 2, 0 Hydropower sites, 127 Solar PV sites with total installed capacity of 127 MWp, 9 Biomass sites with total installed capacity of 3 MW and 0 Wind power sites were selected. In Province 3, 33 Hydropower sites with total installed capacity of 26.4 MW, 70 Solar PV sites with total installed capacity of 70 MWp, 16 Biomass sites with total installed capacity of 8.7 MW and 0 Wind power sites were selected.

In Province 4, 25 Hydropower sites with total installed capacity of 22.4 MW, 58 Solar PV sites with total installed capacity of 58 MWp, 2 Biomass sites with total installed capacity of 1.5 MW and 0 Wind power sites were selected. In Province 5, 16 Hydropower sites with total installed capacity of 12.6 MW, 85 Solar PV sites with total installed capacity of 85 MWp, 8 Biomass sites with total installed capacity of 2.3 MW and 0 Wind power sites were selected. In Province 6, 45 Hydropower sites with total installed capacity of 43.1 MW, 33 Solar PV sites with total installed capacity of 33 MWp, 1 Biomass sites with total installed capacity of 0.3 MW and 0 Wind power sites were selected. In Province 7, 48 Hydropower sites with total installed capacity of 44.9 MW (which was the highest installed capacity for Hydropower selected in a Province), 37 Solar PV sites with total installed capacity of 37 MW, 3 Biomass sites with total installed capacity of 1.1 MW and 0 Wind power sites were selected.

Overall, 221 Hydropower sites with total installed capacity of 192.6 MW, 481 Solar PV sites with total installed capacity of 481 MWp, 50 Biomass sites with total installed capacity of 20.4 MW and 1 Wind power site with installed capacity of 0.2 MW were selected in the whole country.

1.2.4.3 Investment and Viability Gap Funding (VGF)

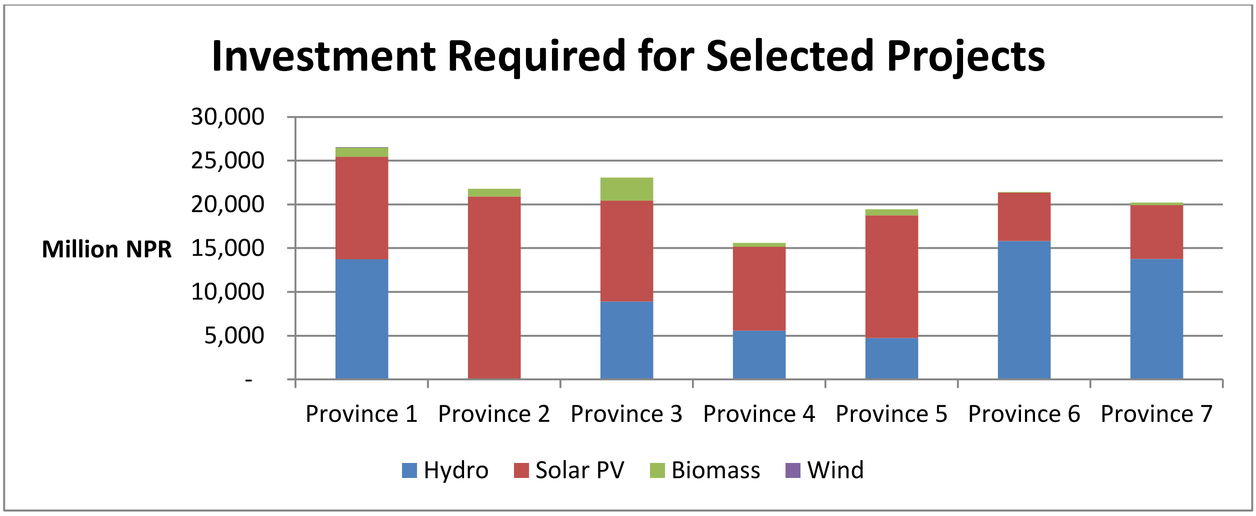

Figure 13 : Investment required for selected DG projects

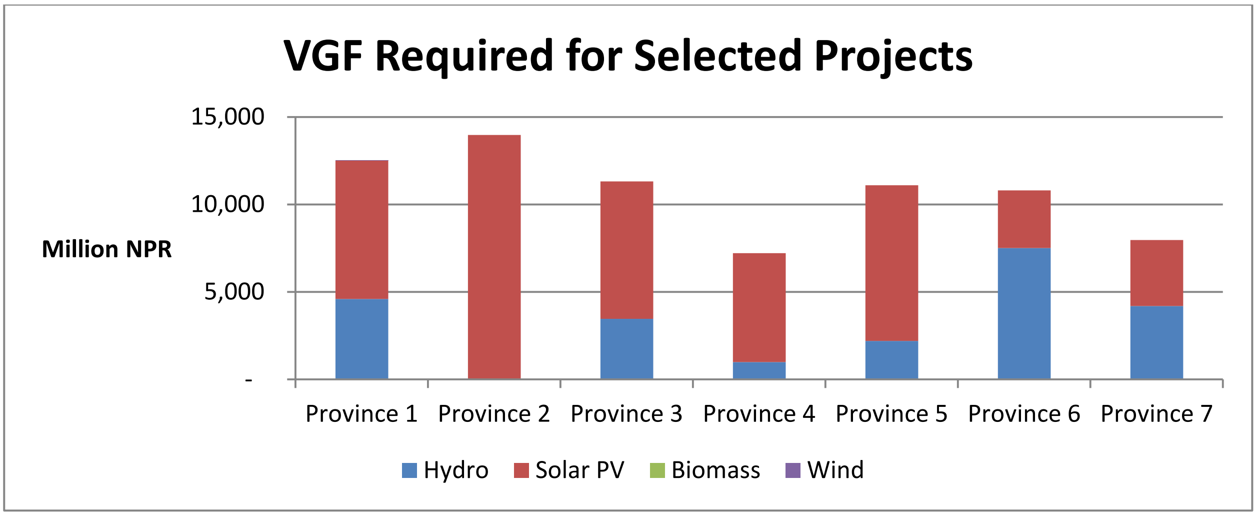

Figure 14 : Viability Gap Funding (VGF) required for selected DG projects

For Province 1, the Total Investment required for Hydropower was NPR 13.74 billion, for Solar was NPR 11.71 billion, for Biomass was NPR 1.06 billion and for Wind was NPR 40 million. Similarly, the Total Viability Gap Funding (VGF) required for Hydropower was NPR 4.5 billion, for Solar was NPR 7.9 billion and for Wind was NPR 12 million. Since Biomass projects had an ROE above 15%, no VGF was required. For Province 2, the Total Investment required for Solar was NPR 20.91 billion, and for Biomass was NPR 893 million. Similarly, the Total VGF required for Solar was NPR 13.9 billion. For Province 3, the Total Investment required for Hydropower was NPR 8.89 billion, for Solar was NPR 11.55 billion, and for Biomass was NPR 2.6 billion. Similarly, the Total VGF required for Hydropower was NPR 3.4 billion, and for Solar was NPR 7.8 billion.

For Province 4, the total Investment required for Hydropower was NPR 5.56 billion, for Solar was NPR 9.58 billion, and for Biomass was NPR 450 million. Similarly, the Total VGF required for Hydropower was NPR 987 million, and for Solar was NPR 6.2 billion. In Province 5, the Total Investment required for Hydropower was NPR 4.73 billion, for Solar was NPR 14.02 billion, and for Biomass was NPR 695 million. Similarly, the Total VGF required for Hydropower was NPR 2.1 billion, and for Solar was NPR 8.8 billion. For Province 6, the Total Investment required for Hydropower was NPR 15.84 billion, for Solar was NPR 5.5 billion, and for Biomass was NPR 97 million. Similarly, the Total VGF required for Hydropower was NPR 7.5 billion, and for Solar was NPR 3.2 billion. In Province 7, the Total Investment required for Hydropower was NPR 13.78 billion, for Solar was NPR 6.1 billion, and for Biomass was NPR 317 million. Similarly, the Total VGF required for Hydropower was NPR 4.1 billion, and for Solar was NPR 3.7 billion.

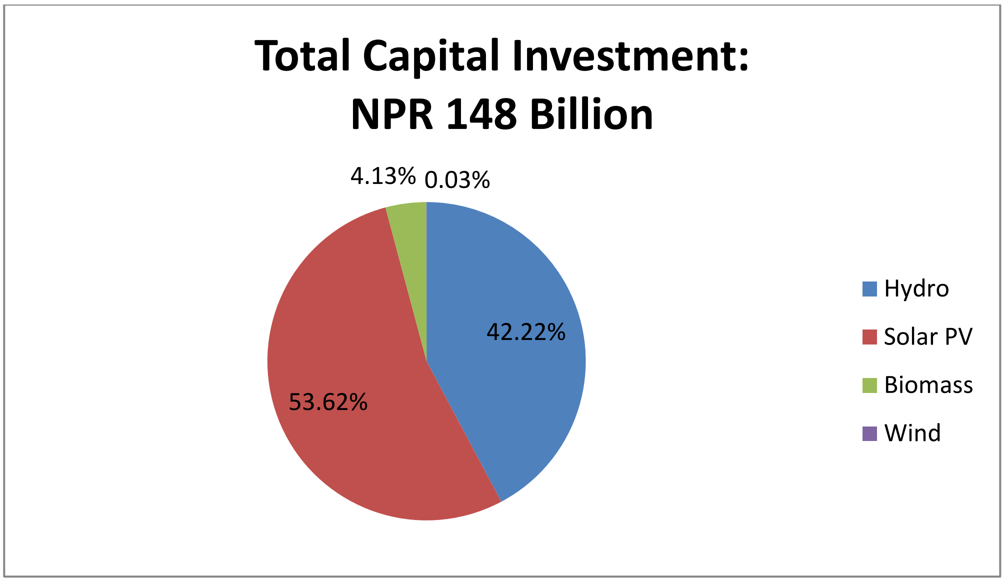

Figure 15 : Total capital investment of DG Projects

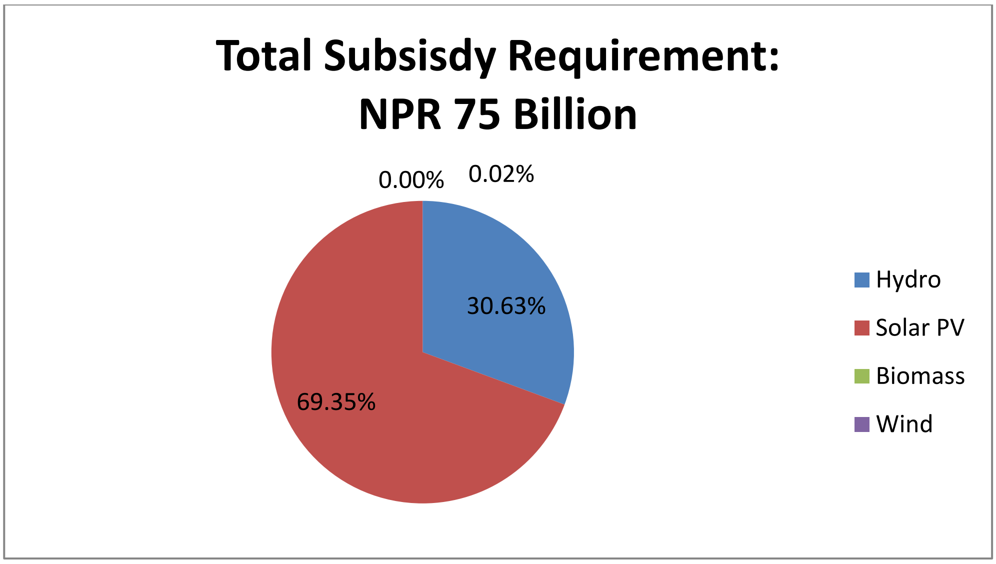

Figure 16: Total Viability Gap Funding (VGF) requirement for DG Projects

Overall, the Total Investment required for Hydropower was NPR 62.54 billion, for Solar was NPR 79.42 billion, and for Biomass was NPR 6.12 billion, and for Wind was NPR 40 million; thus, the Total Investment necessary for whole country was NPR 148.13 billion. The Total VGF required for Hydropower was NPR 22.9 billion, for Solar was NPR 51.9 billion, and for Wind was NPR 12 million; thus, the Total VGF necessary for whole country was NPR 74.88 billion.

1.2.4.4 Average Investment and VGF

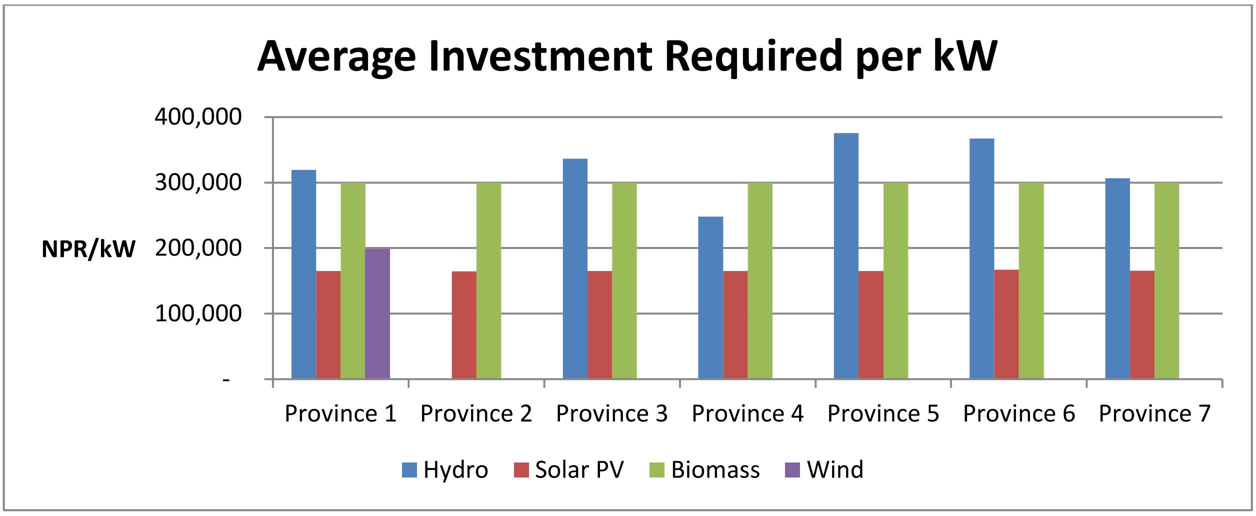

Figure 17 : Average investment required per kW

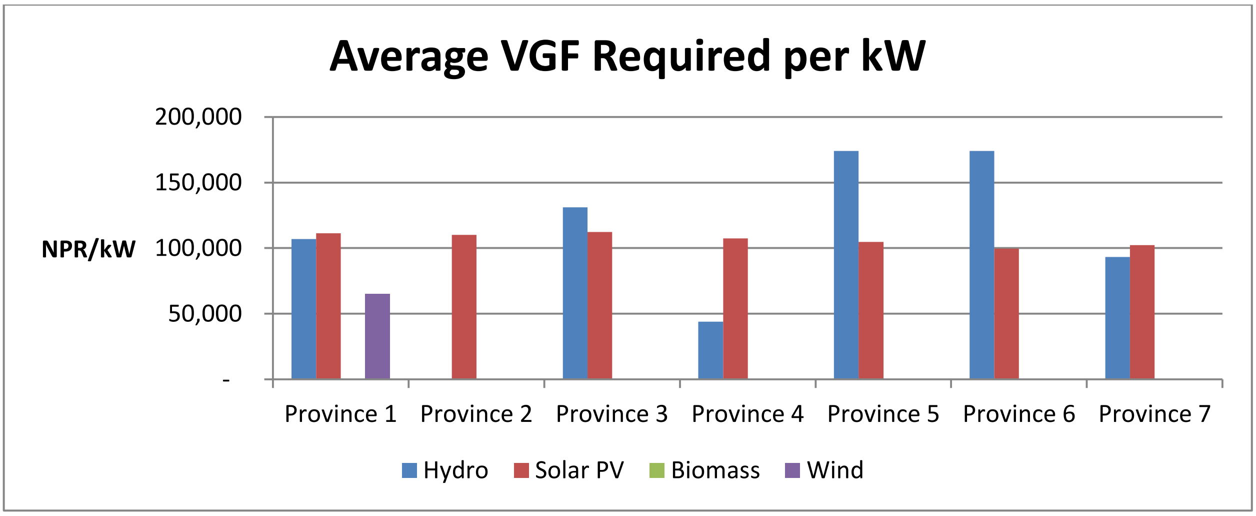

Figure 18 : Average VGF required per kW

In Province 1, on average the Investment required per kW for Hydro was NPR 319,347/ kW, for Solar was NPR 164,963/kW, for Biomass was NPR 300,000/kW and for Wind was NPR 198,250/kW. On average, the VGF required per kW for Hydropower was NPR 106,838/kW, for Solar was NPR 111,394/kW and for Wind was NPR 60,000/kW. In Province 2, on average the Investment required per kW for Solar was NPR 164,661/kW, and for Biomass was NPR 300,000/kW. On average, the VGF required per kW for Solar was NPR 110,000/kW. The highest number and installed capacity of Solar PV sites in the country were selected in Province 2 due to absence of any Hydropower sites. In Province 3, on average the Investment required per kW for Hydro was NPR 336,219/ kW, for Solar was NPR 165,135/kW, and for Biomass was NPR

300,000/kW. On average, the VGF required per kW for Hydropower was NPR 131,032/kW, and for Solar was NPR 112,186/kW. The highest number of Biomass project sites in the country were selected in Province 3.

In Province 4, on average the Investment required per kW for Hydro was NPR 248,127/ kW, which was the lowest in the country for Hydropower, for Solar was NPR 165,268/kW, and for Biomass was NPR 300,000/kW. On average, the VGF required per kW for Hydropower was NPR 44,036/kW, which was the lowest in the country for Hydropower, and for Solar was NPR 107,414/kW. In Province 5, on average the Investment required per kW for Hydro was NPR 375,604/ kW, which was the highest in the country for Hydropower, for Solar was NPR 164,945/kW, and for Biomass was NPR 300,000/kW. On average, the VGF required per kW for Hydropower was NPR 174,074/kW, which was the highest in the country for Hydropower, and for Solar was NPR 104,659/kW. The second highest number of Solar sites and second lowest number of Hydropower sites in the country were selected in Province 5.In Province 6, on average the Investment required per kW for Hydro was NPR 366,889/ kW, for Solar was NPR 167,044/kW, and for Biomass was NPR 300,000/kW. On average, the VGF required per kW for Hydropower was NPR 173,985/kW, and for Solar was NPR 99,727/kW which was the lowest in the country for Solar.In Province 7, on average the Investment required per kW for Hydro was NPR 306,787/ kW, for Solar was NPR 165,575/kW, and for Biomass was NPR 300,000/kW. On average, the VGF required per kW for Hydropower was NPR 93,216/kW, and for Solar was NPR 102,216/kW.

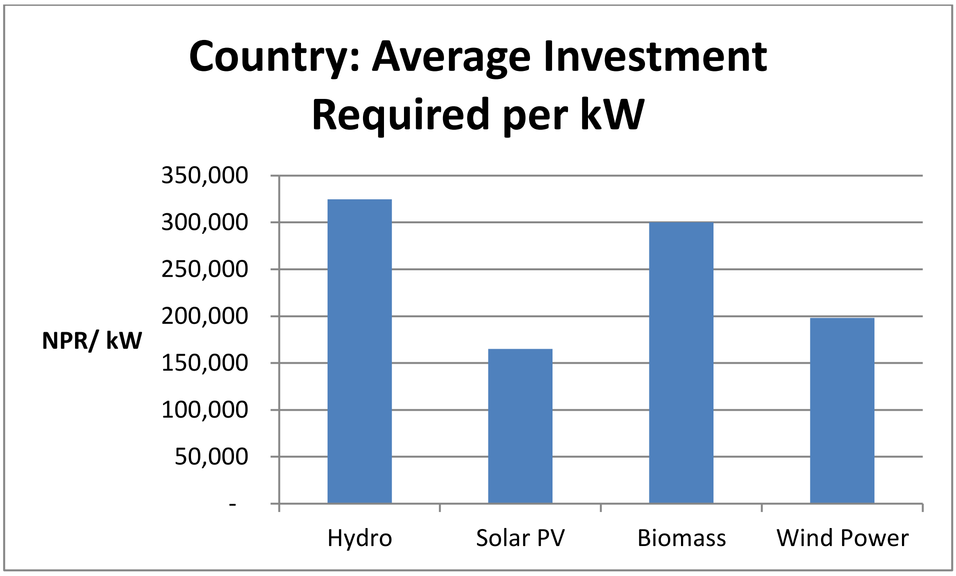

Figure 19 : Average investment required per kW for different types

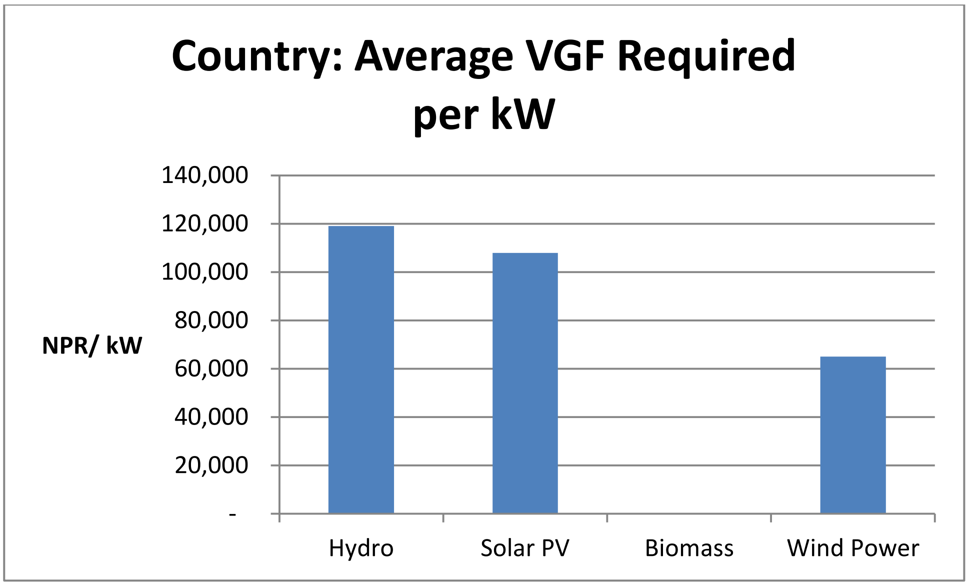

Figure 20 : Average VGF required per kW for different types

For the country, on average the Investment required per kW for Hydro was NPR 324,772/ kW, for Solar was NPR 165,132/kW, and for Biomass was NPR 300,000/kW. On average, the VGF required per kW for Hydropower was NPR 119,110/kW, and for Solar was NPR 107,965/kW.

1.2.4.5 Alternative Cases – Investment and VGF

Table E: Summary of Best DG Projects Selected (Province-wise and Country Total) for Alternative Scenario – Solar PV with 200 kWh battery storage

PROVINCE:	1	2	3	4	5	6	7	Country Total
Investment for Hydro (M-NPR)	13,746	-	8,891	5,563	4,733	15,824	13,784	**62,541**
Investment for Solar PV (M-NPR)	10,334	18,452	10,199	8,458	12,371	4,864	5,405	**70,084**
Investment for Biomass (M-NPR)	1,063	893	2,607	450	695	97	317	**6,122**
Investment for Wind (M-NPR)	40	-	-	-	-	-	-	**40**
Province Total (M-NPR)	**25,183**	**19,345**	**21,697**	**14,471**	**17,799**	**20,785**	**19,507**	**138,787**

PROVINCE:	1	2	3	4	5	6	7	Country Total

VGF for Hydro (M-NPR)	4,599	-	3,465	987	2,194	7,504	4,188	**22,937**
VGF for Solar PV (M-NPR)	6,112	10,795	6,068	4,814	6,874	2,543	2,922	**40,129**
VGF for Biomass (M-NPR)	-	-	-	-	-	-	-	**-**
VGF for Wind (M-NPR)	13	-	-	-	-	-		**13**
Province Total (M-NPR)	**10,724**	**10,795**	**9,533**	**5,801**	**9,068**	**10,047**	**7,110**	**63,079**

Table F: Summary of Best DG Projects Selected (Province-wise and Country Total) for Alternative Scenario – Solar PV without Battery

PROVINCE:	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**Country Total**
Investment for Hydro (M-NPR)	13,746	-	8,891	5,563	4,733	15,824	13,784	**62,541**
Investment for Solar PV (M-NPR)	8,518	15,209	8,407	6,972	10,196	4,009	4,455	**57,766**
Investment for Biomass (M-NPR)	1,063	893	2,607	450	695	97	317	**6,122**
Investment for Wind (M-NPR)	40	-	-	-	-	-	-	**40**
Province Total (M-NPR)	**23,367**	**16,102**	**19,905**	**12,985**	**15,624**	**19,930**	**18,557**	**126,469**

PROVINCE:	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**Country Total**
VGF for Hydro (M-NPR)	4,599	-	3,465	987	2,194	7,504	4,188	**22,937**
VGF for Solar PV (M-NPR)	4,314	7,620	4,283	3,398	4,852	1,795	2,063	**28,326**
VGF for Biomass (M-NPR)	-	-	-	-	-	-	-	**-**
VGF for Wind (M-NPR)	13	-	-	-	-	-		**13**
Province Total (M-NPR)	**8,926**	**7,620**	**7,748**	**4,385**	**7,046**	**9,299**	**6,251**	**51,276**

The Tables above show that changes in Total Investment and VGF required for Alternative Scenarios of Solar PV with 200 kWh battery and NO battery storage respectively. As can be seen from the tables, the Total Investment decreases significantly from NPR 148 Billion for

Base Case of Solar PV with 500 kWh battery to NPR 138 Billion and NPR 126 Billion for Alternative Scenarios of Solar PV with 200 kWh battery and NO battery storage respectively. Similarly the Total Viability Gap Funding (VGF) decreases significantly from NPR 74 Billion for Base Case of Solar PV with 500 kWh battery to NPR 63 Billion and NPR 51 Billion for Alternative Scenarios of Solar PV with 200 kWh battery and NO battery storage respectively. On average, the VGF required per kW for Solar with 200 kWh was approx. NPR 85,000 and for Solar with NO battery storage was approx. NPR 60,000. Nonetheless, these scenarios with less or no battery storage would comprise on the aspect of electricity reliability in case the central grid is down during the evening or nights.

1.2.5 Recommendations and Conclusion:

1.2.5.1 Economic Analysis

Economic Analysis is undertaken for two representative models of dispersed generation (Province 1) and high load density (Province 2) and comparison is made between economic scenario of each Province for Grid Extension with and without DG. Scenario A considers Grid Extension with DG, which includes Capital and O&M costs of selected DG plants, T&D Network expansion and necessary Central Hydro plants to completely supply the load. For this scenario, Transmission & Distribution Network Loss is considered as 9%. Scenario B considers Grid Extension without DG, which includes Capital and O&M costs of T&D Network expansion and Central Hydro plants that can supply same level energy as the previous scenario. For this scenario, Transmission & Distribution Network Loss is considered as 18%. Social/Economic Discount Rate (SDR) is assumed to be 2%, which is calculated by averaging the interest on Treasury-bills (364 days) over a period of 4 years (15 data points) as published by Nepal Rastriya Bank (Quarterly Economic Bulletin, July 2017) and adding 0.7% for market distortion. Economic analysis is performed for project lifetime of 25 years.

Table G: Results of Economic Analysis and Sensitivity Analysis

Scenario / Economic Indicators	Province 1		Province 2	
	Scenario A: Grid Extension with DG	**Scenario B: Grid Extension without DG**	**Scenario A: Grid Extension with DG**	**Scenario B: Grid Extension without DG**
	Network Loss = 9%	Network Loss = 18%	Network Loss = 9%	Network Loss = 18%
Base Case: SDR = 2%				
NPV (NPR- Billion)	736	671	940	861
EIRR	39.33%	39.36%	42.54%	43.03%
PBP (years)	2.54	2.53	2.35	2.32
Case I: SDR = 5%				
NPV (NPR- Billion)	642	456	643	589
Case II: SDR = 8%				
NPV (NPR- Billion)	352	321	455	418

Province 1

In Province 1, 54 Hydropower sites with total installed capacity of 43 MW (which was the highest number of Hydropower sites selected in a Province), 71 Solar PV sites with total installed capacity of 71 MWp, 11 Biomass sites with total installed capacity of 3.5 MW and 1 Wind power site with total installed capacity of 0.2 MW were selected through financial analysis.

As shown in Table G for the Base Case (SDR = 2%) of Province 1, the Net Present Value (NPV) is highest for Scenario A: Grid Extension with DG at NPR 736 billion. Scenario B: Grid Extension without DG yields lower NPV of NPR 671 billion. Similarly, both Scenarios have similar Economic Internal Rate of Return (EIRR) of approximately 39% and Pay Back Period (PBP) of approx. 2.5 years. As Economic evaluation considers the NPV while ranking projects, i.e. the net value added to the economy, Grid Extension with DG is recommended for Province 1.

Sensitivity Analysis at higher SDR of 5% (Case I) shows that that NPV decreases to NPR 642 billion for Scenario A and to NPR 456 billion for Scenario B; nonetheless, the net economic value added is still higher for Scenario A. Similarly, Sensitivity Analysis at highest SDR of 8% (Case II) shows that that NPV decreases to NPR 352 billion for Scenario A and to NPR 321 billion for Scenario B; nonetheless, the net economic value added is still higher for Scenario A. Also, preliminary analysis shows that the results of economic analysis for Provinces 3, 4, 5, 6 & 7 would be similar to that of Province 1 (due to similar load and generation profile).

Province 2

In Province 2, no hydropower sites were found. 127 Solar PV sites with total installed capacity of 127 MWp, and 9 Biomass sites with total installed capacity of 3 MW were selected through financial analysis. The highest number and installed capacity of Solar PV sites in the country were selected in Province 2 due to absence of any Hydropower potential. Also, the load was the highest for Province 2 due to high population density. As can be seen from the Table G for the Base Case (SDR = 2%) of Province 2, the NPV is highest for Scenario A: Grid Extension with DG at NPR 940 billion. Scenario B: Grid Extension without DG yields lower NPV of NPR 861 billion. Similarly, both Scenarios have similar EIRR of approximately 43% and Pay Back Period (PBP) of approx. 2.3 years. As Economic evaluation considers the NPV while ranking projects, i.e. the net value added to the economy, Grid Extension with DG is recommended for Province 2 as well.

Sensitivity Analysis at higher SDR of 5% (Case I) shows that that NPV decreases to NPR 643 billion for Scenario A and to NPR 589 billion for Scenario B; nonetheless, the net economic value added is still higher for Scenario A. Similarly, Sensitivity Analysis at highest SDR of 8% (Case II) shows that that NPV decreases to NPR 455 billion for Scenario A and to NPR 418 billion for Scenario B; nonetheless, the net economic value added is still higher for Scenario A.

The economic model captures the following elements: (i) Reduction of Capital and Operational expenditure of Transmission and Distribution networks (Grid Extension) due to active and reactive power support by DG plants (ii) Reduction of Network Losses due to DG plants servicing local loads and improvement in grid voltage and performance, and (iii) Economic benefits from fuel replacement and willingness to pay according to the electrification status of the Municipality.

However, due to limitations of time and scarcity of published local research, additional economic benefits of Grid Extension with DG such as (i) fewer social and environmental consequences over large central plants, and (ii) ripple economic effect through forward and backward economic linkages that can kick-start the local economy could not be captured in the model. If they were to be considered, the NPV and EIRR of Scenario A: Grid Extension with DG would be higher for all Provinces.

Further, economic costs of GHG emissions over the project lifetime is not considered. Over the project lifetime, GHG emissions of hydropower would be slightly higher (diesel usage over longer construction period and low-level emissions from submerged plants) than Solar PV, but both of these renewable technologies would have minimal GHG emissions when compared to fossil fuel plants such as coal or gas fired plants. Benefits of GHG mitigation are also not considered in the model; the NPV and EIRR would increase for both Scenarios if they were to be considered.

1.2.5.2 Implementation Modality

There are few underlying concepts in the proposed solution, namely, investment in distributed generation projects in all municipalities as a means of increasing local economic growth in one side, and expansion of national grid through sub-transmission and distribution lines to all of the municipalities in the other. The underlying concepts include improving local capability in institutional management and distributing VGF for equitable development. The implementation modality needs to address all these four underlying concepts.

The two technical sides of the Concept for Implementation

The fundamental concept of Bi-directional planning and implementation for Sustainable Distributed Generation and Grid Access to All (SUDIGGA) is that it has to work on both sides of the power system: at the local levels, locating a substation that best serves the local distribution network plan and constructing generation projects to feed the network and at the central grid side, constructing radial network expansion targeted and homing towards the substations at the local municipalities.

Distributed Generation projects

There are 221 Hydropower projects, 481 Solar PV projects and 50 Biomass to electricity projects, and 1 Wind power project recommended to be constructed. The generation projects development cycle necessarily contains following phases:

a) Feasibility Study and Detail Engineering Study
b) Financing of the project construction and concluding operational issues such as power sale
c) Formation of implementing agencies for local ownership of the generation projects, government agency for assisting the local governments to set-up the local vehicles,

oversee the engineering of the projects and facilitate the equity, debt and VGF financing

d) Contract management, construction management, and generation upon commissioning

e) Operationalization of the plant operation agency and expansion of Low voltage distribution network to consumers

Expansion of Grid – Sub-transmission and distribution line and substation projects

There are 196 km of 132 kV sub-transmission lines, 8 number of 132/33 kV substation with 188MVA of transformer capacity, 5568 kms of 33 kV distribution lines, 323 Nos of 33/11 kV substations and 2063 kms of 11 kV lines with 199 Nos of 11kV switching stations for interconnection of generation projects and distribution feeders. These grid expansion projects require step-wise implementation.

Step-wise Expansion

Step-wise implementation is necessitated by the sequential nature of the expansion works as well as the need of temporally distributing the huge costs of expansion. The network expansion will start from the existing and under-construction substations of Nepal Electricity Authority. The outward expansion in first stage will consist of sub-transmission lines and 33 kV lines with substations at the end of the radial lines. The phasing may be in three or more stages. The costs of different stages of phased expansion is given in table below with details of the substation and Lines.

Table H: Implementation Activities

Phase	Duration (yrs.)	No. of 132/33 kV Substations	No. of 33/11 Substations	No. of 11 kV switching stations	Length of 132 kV line	Length of 33 kV line	Length of 11 kV line	Estimated Cost (NPR in Million)
1	2.5	5	79	20	100	1540	270	14156.17
2	1(+1.5 overlap)	3	145	79	96.2	1895	843	22320.53
3	1(+2.5 overlap)	0	99	100	0	2133.4	950.9	17326,2
Total	**4.5**	**8**	**323**	**199**	**196.2**	**5568.4**	**2063.9**	**53802**

Time-line

The time-duration for the phased expansion alternatives are given in table above. The timetable covers the different activities required in implementing the expansion work, the detail of the activities are as given below.

a) Feasibility survey of the lines and substations, and detail design including tender document preparation
b) Financing of the expansion project – national budget and investment planning and allocation for the expansion works.
c) Facilitation with the implementing agency Nepal Electricity Authority or its Distribution agencies in the respective provinces in cooperation with the local municipality for eventual modality of operation of distribution network.
d) Contract management and construction supervision by NEA and the operating agency at the level of local municipality
e) Operationalization of the entity responsible for substation and distribution and expansion of Low voltage distribution network to consumers

The sequence of programs as listed above will be rolled out and put in place for each phase of the expansion project. The total time-plan for the above five activities for beginning of first phase to the end of the third phase will be within the five year timeframe as follows:

Table I: Results of Economic Analysis and Sensitivity Analysis

Activity	Description of Work	Remarks
1	Project Verification	Within 12 Months
2	Feasibility and Detail Study	Within 18 Months
3	Financial Arrangement	Within 30 Months
4	Project Construction	Within 54 Months
5	Grid Extension	Within 54 Months
6	Project in Operation	Within 60 Months

Medium voltage transformer stations and Low Voltage distribution Network Expansion

The SDG7 and SE4ALL accomplishment includes the last mile connection to the consumer households. This study does not cover the last mile planning, as it is vast scope of work and such planning and investment decisions are best left to the Local Government bodies. However, it has to be noted here that in order to accomplish the Energy Access for All , planning for the last mile connection, and its financing must begin immediately after the launch of the first phase of the Grid

Expansion, such that there is a seamless connection to the households and supply of electricity at the completion of the Five Year project.

It is understood that Nepal Electricity Authority is undertaking a Distribution Masterplan that includes the Medium Voltage transformer stations, their capacity and aggregated nodes of the low voltage lines. It is also understood that the above Master Plan does not include detail GIS based distribution network planning. It is therefore necessary that next phase of implementation should include GIS mapping of the Medium Voltage transformers and planning of Low Voltage network that is optimized with updated GIS data of population and load demand.

Monitoring of Operation and Maintenance and support system

The operation and maintenance of 11 kV switching substation and feeder lines as well as 33 kV substation and distribution lines can be done by local level agencies as the technology and know-how required is easily available and man-power can be trained. The cost of operation and monitoring increases with the location of the agency being farther from the area. The cost of logistics and additional costs incurred for man-power migration makes such operation not viable for these agencies. Hence, a local entity is preferred.

However, for large events, such as damage to 33kV transformer or circuit breaker or substation control and protection systems, the local entity will require external support. This will be more prominent in remote areas. For this reason, a regional or provincial support cell or entity need to be established to provide such operational support.

The Governance aspects of the Concept for Implementation

The SUDGGAA is feasible only with a meaningful participation from the local government bodies which will ensure sustainability of the project. The Constitution of Nepal 2072 mandates three levels of governance with definite rights and duties of the local bodies, which are empowered to legislate on subjects as listed in the Schedules of the Constitution. The Schedule 6 lists electricity distribution as the jurisdiction of Provincial government while the Schedule 8 lists the renewable generation projects as the jurisdiction of Local government. In recognition of the constitutional mandates, the Implementation Plan will need to enlist support and participation of the respective governments in formulating the projects as well as forming the entities responsible for implementing and operating them.

Agency for the Distributed generation projects

The Distributed generation projects are proposed as joint investment projects, with federal support as grant money for funding the viability gap while the local municipalities and cooperatives and directly Project affected people are supposed to invest the main equity. The capital required for constructing a generation project will be large ranging from NPR 16 Crores (USD 1 million) to NPR 30 Crores (USD 3 million), it is a natural proposition that a separate company shall be formed where the financing requirement after Viability Gap Fund is provided with equity injection (20-30%) from municipality, cooperatives and project affected people, and the remaining 70 to 80% of the finance requirement is secured from low-interest development loans from multi-lateral institutions or the government or by priority sector lending from national finance institutions.

a) Independent Generation Company – An independent public limited company is best suited to run the generation project and associated assets. The generation company may be wholly owned by the local municipality. It may also have alternative equity holding shared with local project-affected community or their cooperatives. This contributes towards more consolidated Sustainability of the generation project with shared and aligned interests of the very localized community.

b) Central utility holding - In the cases of remote municipalities, the operation of the distribution network and providing service to the consumer from an entity based in province capital city has proven to be financially unviable and burdensome for the central utility. In such cases, the central utility is inclined to lease the operation of the network to community electrification users groups (CEUG). There are mixed experiences with CEUG networks over time. Reduction in non-technical losses have been recorded, but reliability and quality of service has not improved.

c) Municipality managed utility ownership – Local ownership may reduce operational costs but a municipality owned and operated utility will be a microcosm of a government with utility at the center, which has been shown to be ineffective and consequently expensive, and hence, disowned by government at central level previously. It is therefore not recommended to keep such generation and distribution assets directly under the municipality.

d) Local Utility Company with combined generation and distribution assets – Presently, the Electricity Act requires that generation, transmission and distribution companies should be separate entities with separate licenses. At the local level, such demarcation is not essential as long as the transmission network is separated. The local generation project with Viability Gap Funding to utilize locally available energy resources is expected to lower the cost of local electricity. A joint utility will be also able to compensate for the high cost of providing distribution services.

   From stakeholders' workshops and discussions with experts, it has emerged that the best format for Ownership of the generation project and consequent development, and operation is a Separate Public Company (Special Purpose Vehicle SPV). The shareholding of such a SPV is recommended to be evenly distributed amongst the municipality to provide the financial strength in case of shortfalls, and cooperatives of the project area and cooperatives of the electricity users and community user groups. Single group ownership still can not be relied upon to function effectively.

   Since the generation project requires grant in terms of viability gap fund, the ownership of the SPV needs to have a broad public ownership and ensure that no private individual or business is owning disproportionately.

<u>Agency for the distribution network</u>

a) Central Utility holding – the construction of the line and substations are proposed to be completed in a condensed and intensive program within 5 years. Such program can be successful only if implemented by the central Utility having sufficient technical and organizational capability which is NEA in the present context. However, eventual ownership transfer or leasing to local utility is possible.

b) For town municipalities, the central and provincial utilities are inclined to maintain their ownership and they may also be well equipped to do so. Nonetheless, there could be other alternatives because the electricity supply business is undergoing rapid change. Even in South Asia, there are examples where wire and services are separated. In such a case, the wires can be owned by any of the models of a private or public company or a municipality-owned company.

   From stakeholders' workshops and discussions with experts, it has emerged that the best format for Ownership of the Distribution Network is the SPV that owns the generation company itself, as the financial benefit of the generation project will balance the costs of distribution and maintaining the feeder from the grid. The generation company will be induced to maintain the connecting line to grid as the surplus energy supplied to grid provides the financial surplus to it.

   Since the distribution network needs a separate license and there are issues of overlap with the Central Utility or its subsidiary, the Initial phase of distribution network from the Grid till the local substation need to be with the Central Utility that constructs and completes the Grid Expansion. This is further so if the connecting line supplies power to more of the municipalities and hence, a SPV ownership will raise the issue of wheeling charges.

   In remote areas, the cost of maintaining and operating these interconnecting lines will be uneconomically high for central and provincial utility. Thus, a phased hand-over of the interconnecting lines to the SPV is foreseen with a framework of wheeling charge or management charge in place before that.

<u>Financing of the SUDIGGAA</u>

A major component of the SUDIGGA project is the Viability Gap Funding (VGF) to be provided by federal government. Substantial VGF is required for generation projects while the wires have to be fully funded by the federal government.

- It is assumed that providing a level field for economic growth to all of the municipalities in principle that will be accepted and be one of the priorities of future governments. Electricity is not only considered a basic necessity in modern times, but it is the essential input for industrial growth, employment and development. Providing VGF for generation projects that enables grid expansion to remote areas is a necessary step forward in this direction. However, it is assumed that equitable VGF distribution will be called for by all municipalities. Such VGF, if provided, may not be applicable for similar hydro-projects but may be more appropriate for alternatives that provide better electricity at lower prices. This is the principle that allows planning of solar projects in areas that are already electrified, and bio-mass projects from solid waste in towns where even solar projects are not feasible due to high land costs, customs duties, etc.
- Viability Gap Fund vs. Benchmark VGF – Identifying the best possible generation project and then determining the viability gap fund is complex and tends to be convoluted. A mechanism to incentivize local body to find the best project is to set a benchmark VGF, and

allow the municipalities to find the best project within the limits of the benchmark VGF. Viability gap fund helps to find the equitable proportion of VGF for remote and less-endowed municipalities. The lack of sufficient experience and culture of in such viability gap determination, and the need to undertake this exercise in all 753 units in a short period calls for a simplified VGF program. A benchmark VGF policy is therefore recommended.

VGF for generation-projects and financial viability

The hydro-projects have been selected with design discharge of 65% probability of exceedance. Projects with such design have plant factor of approximately 65% (at the grid connection point after accounting for all losses). The economic value of the energy in an already electrified area is the 'Willingness to Pay' of the consumers. A survey done by MCC, which is yet to conclude the results, is known to have received a preliminary estimate of 27% more than the current price. This same price may be used for determining the economic viability of a project and a criterion for justifying the VGF.The financial viability of the project after VGF is necessary for sustainable operation of the project. Hence, a favorable debt/ equity ratio is proposed for independent stock company such that the local municipality is required to put up minimum of equity fund.

For a 1000 kW hydro-project, the median cost of construction of a hydro-project is approximately USD 3500/ kW and generating approximately 6 million units in a year. A benchmark VGF of USD 1000/ kW will require about USD 2.5 million capital in 4 to 5 years from the local government. A debt/equity ratio of 80/20 will ease the capital requirement from the local municipality to USD 500,000 (approximately NPR 5 Crore) in 4 to 5 years, which is an outlay of USD 100,000 (approx.NPR 1 Crore) per year.

This projection is assumed to be feasible for all of the municipalities. A comparison with present Independent Power Producer (IPP) projects gives projects that have median construction costs of 2000 $/ kw for Q40 (having 5 million units a year) design discharges. Extrapolating the costs for Q65 (6 million units a year) and with a better wet-energy to dry-energy ratio, the financially viable cost of such projects lie around 2500$/kW.

However, for remote areas which are far from the road head, the remoteness factor has to be accounted. A remoteness factor of 1.2 is considered for higher cost of transportation of construction materials and in some heavy single transport cases, heli-lifting. Thus, projects of 4500$/kW are also selected for construction in such remote areas. Nonetheless, it is proposed that a benchmark VGF of 1000$ / kW or NPR 10 crore per MW be considered for accomplishing SUDIGGAA. For projects that have high transport costs, alternative solar or biomass projects could be considered, or they could be accomplished after appropriate road access is enabled.

From the discussions in the workshops, it has emerged that the benchmark subsidy or viability gap funding should be categorized to few varying VGF slabs taking into account the fact that some of the projects may not require much VGF while some of the remote areas would need a higher amount of VGF. Since the transaction analysis for a detailed work-out f VGF is complex and costs may outweigh the benefits of such exact VGF determination, it is recommended that based on Remoteness factor, three slabs of VGF be proposed, with VGF benchmark of less than

1000$/ kw for projects having road access, and 1000$ / kw for projects that are moderately far from the road-head and 2000$/kW for projects that are at least one-days travel from nearest road-head.

The Levelized Cost of Energy (LCOE) from Solar projects with 500 kWh Battery backup is quite high (NPR 12 to 14per kWh) at present costs of Battery and additional Inverter. For financial viability, VGF in the range of USD 1000 to 1100 is required out of the total Capital Cost of USD 1600 -1700/ kW. Even for Solar Project without any Battery Backup, LCOE of 1 MWac Solar PV Project is too high (NPR 9 to 10/ kWh); therefore, either NEA PPA Rate of around NPR 10/ kWh (with 8 simple escalations of 3% each) or Federal VGF of around USD 600/kW is necessary. Large part of the high cost is contributed by the price of land, and low capacity utilization factor (CUF) of solar. Nonetheless, it would be unfair to compare Solar PV without any battery storage to Hydropower and Biomass technologies, as the Solar PV would not be able to supply any electricity during nights in the event the central grid is down, thus compromising on the aspect of reliability of supply. A middle ground could be to develop Solar PV with Battery in two phases, such that Solar PV without Battery but with adequate space for adding batteries and inverters later is developed in the first phase, and additional Inverter and Battery necessary is added in the subsequent phases. This will help to break the Total Investments and VGF into multiple phases while providing the flexibility of achieving increasing level of reliability from the project over time. Since a benchmark VGF with three slabs is considered for hydro, same structure of VGF (i.e. USD 1000/ kW) is proposed for Solar PV plant with 500/ 200 kWh battery storage.

In the case of Biomass, high plant load factor, income from sale of electricity to NEA and additional income from sale of fertilizer byproduct results in a very attractive ROE such that no VGF is required. Nonetheless, due to scarcity of well-established waste collection system, and pilot projects for testing business models; the benchmark VGF of USD 1000/kW will also be appropriate for 50 selected Biomass Plants. For one selected 200kW Wind power plant with high wind resources available locally, the VGF required is about USD 600/ kW.

2 INTRODUCTION

2.1 PROJECT OVERVIEW

This draft report presents the preliminary findings of the "Study and Analysis of Optimal Distributed Generation for Access to Grid Electricity for All in Five Years with Participation from Local-level Government" project.

2.1.1 Project Information

The National Planning Commission (NPC) has commissioned the NEA Engineering Company to conduct "Study and Analysis of Optimal Distributed Generation for Access to Grid Electricity for All in Five Years with Participation from Local-level Government" project. The National Planning Commission (NPC), headed by the Prime Minister of Nepal, is the apex advisory body of the Government of Nepal for formulating a national vision, periodic plans and policies for development. The NPC assesses resource needs, identifies sources of funding, and allocates budget for socio-economic development, while serving as the central agency for monitoring and evaluating development plans, policies and programs.

This project studies the optimal Distributed Generation (DG) development and Transmission and Distribution (T&D) network extension pathway to increase access to electricity in all 753 municipalities of Nepal. Access to electricity has very high economic benefits. Electricity reduces human drudgery, enhances comfort, and enables safer and cleaner environment. It boosts productivity and economic activity, creates jobs, and facilitates delivery of education, health and government services. Recognizing these benefits, the United Nations (UN) led Sustainable Energy for All (SE4ALL) initiative seeks to ensure universal access to modern energy services and the Sustainable Development Goal 7 (SDG7) seeks to ensure access to affordable, reliable, sustainable and modern energy for everyone by 2030.

2.2 THE GLOBAL CONTEXT

At the global level, the problems in the energy and environment field are very diverse. On one hand, high-income nations with high energy-intensity are accelerating efforts to curb the use of fossil fuel to combat climate change. Whereas on the other hand, more than a billion people in low- or middle-income countries of South Asia and Africa have no access to modern electricity services. Access to electricity reduces human drudgery, enhances comfort and enables safer and cleaner environment. It boosts productivity and economic activity, creates jobs, and facilitates delivery of education, health and government services. As services provided by energy are critical ingredients of socioeconomic development, there is an urgent need to enable modern electricity services for everyone. Inadequate supply of electricity has been identified as the main constraint to economic growth of the country. Access to grid electricity is a service that many of the villages in Nepal aspire for. Quality electricity necessary for industrial activity is not available to the isolated networks supplied by either roof-top solar or micro-hydro plants. A workable solution in a short time-frame to provide access to grid electricity is something the government would be very eager to implement.

Recognizing the benefits of modern energy, the United Nations (UN) led Sustainable Energy for All (SE4ALL) initiative seeks to ensure universal access to modern energy services and the Sustainable Development Goal 7 (SDG7) seeks to ensure access to affordable, reliable, sustainable and modern energy for everyone by 2030. A Multi-Tier Framework (MTF) for household electricity access (shown in Table I) has been developed to measure and track SE4ALL and SDG7 energy access goals and targets, which have also been adopted by the GoN.

The perils of destabilizing the climate through the unabated use of fossil fuel in electricity generation have elucidated that Renewable Energy Technologies (RETs) must play the leading role to achieve "universal access to electricity" (currently defined as at least Tier 3 electricity access level of the MTF) by 2030. However, for countries like Nepal with limited government resources, the prospect of enabling energy access through renewable technologies comes with many challenges.

Nepal is a mountainous country with 83% of its land lying in hills and high mountains. Almost 50% of its population is still living in the hilly region[1]. The high investments required in constructing distribution networks to the remote areas have hindered government efforts in the past to provide access to electricity for communities living in the remote areas.

Nepalese economy is predominated by agriculture. In rural communities, shortage of energy negatively impacts economic development by suppressing agricultural productivity, health care, education and enterprises. The poor and rural households spend a large part of their income and time fulfilling their basic energy needs.

It is estimated that 30% of the total population mostly in the remote villages are still under darkness. Using the data of the number of customers that Nepal Electricity Authority and some small scale distributors serve, and the average size of the household, it is estimated that only 60% of the population has access to Grid electricity, and geographically, more than 60% of the country

[1] CBS census report 2071

is not reached by any extensions of national grid.

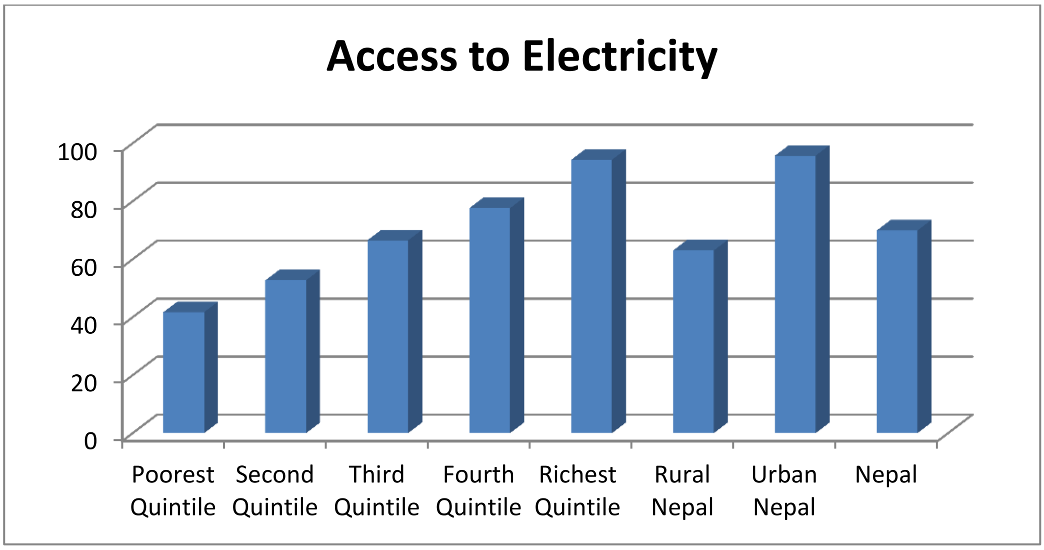

Figure 21: Access to Electricity (Source: NLSS, 2012)

Figure 21 presents access to electricity in Nepal according to economic quintile. Only about 40 percent of poorest 20 percent households have access to electricity as compared to 90 percent of richest 20 percent households. As electricity has impacts on education, health, labor productivity, and quality of life, the disparity in access to electricity has longer term implications on social equity and justice e. Mountain districts, mid- and far-western development regions, and rural areas of Nepal are more adversely affected by the lack of transmission lines.

Table 1 : Multi-tier matrix for household electricity supply, services, and consumption (Source: World Bank 2015)

Multi-tier Matrix for Access to Household Electricity Supply

ATTRIBUTES		TIER 0	TIER 1	TIER 2	TIER 3	TIER 4	TIER 5
1. Capacity	Power[1]		Very Low Power Min 3 W	Low Power Min 50 W	Medium Power Min 200 W	High Power Min 800 W	Very High Power Min 2 kW
	AND Daily Capacity		Min 12 Wh	Min 200 Wh	Min 1.0 kWh	Min 3.4 kWh	Min 8.2 kWh
	OR Services		Lighting of 1,000 lmhrs per day and phone charging	Electrical lighting, air circulation, television, and phone charging are possible			
2. Duration	Hours per day		Min 4 hrs	Min 4 hrs	Min 8 hrs	Min 16 hrs	Min 23 hrs
	Hours per evening		Min 1 hrs	Min 2 hrs	Min 3 hrs	Min 4 hrs	Min 4 hrs
3. Reliability						Max 14 disruptions per week	Max 3 disruptions per week of total duration < 2 hours
4. Quality						Voltage problems do not affect the use of desired appliances	
5. Affordability					Cost of a standard consumption package of 365 kWh per annum is less than 5% of household income		
6. Legality						Bill is paid to the utility, prepaid card seller, or authorized representative	
7. Health and Safety						Absence of past accidents and perception of high risk in the future	

[1] *The minimum power capacity ratings in watts are indicative, particularly for Tier 1 and Tier 2, as the efficiency of end-user appliances is critical to determining the real level of capacity, and thus the type of electricity services that can be performed.*

Multi-tier Matrix for Access to Household Electricity Services

	TIER 0	TIER 1	TIER 2	TIER 3	TIER 4	TIER 5
Tier criteria	Not applicable	Task lighting Phone charging	General lighting Television Fan (if needed)	Tier 2 AND Any medium-power appliances	Tier 3 AND Any high-power appliances	Tier 4 AND Any very high-power appliances

Multi-tier Matrix for Electricity Consumption

	TIER 0	TIER 1	TIER 2	TIER 3	TIER 4	TIER 5
Annual consumption levels, in kilowatt-hours (kWh)	<4.5	≥4.5	≥73	≥365	≥1,250	≥3,000
Daily consumption levels, in watt-hours (Wh)	<12	≥12	≥200	≥1,000	≥3,425	≥8,219

2.3 IDENTIFICATION OF THE CHALLENGES

The difficulties in enabling access to electricity in scattered settlements of the Hilly and Mountainous regions of Nepal due to underdeveloped road and transmission links is a major challenge in achieving SE4ALL goals. The central electricity grid also known as the Integrated Nepal Power System (INPS) is managed by Nepal Electricity Authority (NEA). Unplanned and random extension of the grid to industries, densely populated areas, or villages is a burden for Planners at national level and the central utility NEA as well. Moreover, demand consistently outweighs supply resulting in a disproportionate dependence on import of power from India at some limited points of import. In absence of such imports, scheduled power outages are likely to result which is known as load shedding.

For off-grid population, the Alternative Energy Promotion Centre (AEPC), has been promoting and subsidizing renewable technologies for low levels of energy access for 25% of the population. Unlike the central grid, isolated off-grid networks are unable to provide either reliable or robust supply to support industrial usage of electricity, thus limiting its growth and value addition. For accelerated boost to productivity and the economy, central grid access is a must. Moreover, community-based isolated micro-hydro or solar projects have shown system weakness of unsustainable operation. Subsidy provided to communities who help build and operate these plants have resulted in long-term dependence upon further Subsidy. Off-grid electricity, which is of poor quality and reliability, is still supplied at a higher price per energy unit.

More than 15% of the population has no access to either on-grid or off-grid electricity. Biomass supplies 85% of the total final energy mix and the average per capita electricity consumption annually (including domestic and commercial consumers) is only around 150 kWh.

2.4 EXPLORATION OF FEASIBLE SOLUTIONS

Expanding Transmission and Distribution (T&D) network at High Voltage (66 and 132 kV) and Middle Voltage (33 and 11kV) level to all the 753 local bodies is a huge undertaking, which first requires analyzing the feasibility of such a project. Due to the difficulty of extending the central-grid over hilly and mountainous terrain with difficult road access and the lack of other means of production, the financial and economic benefits of such an investment needs to be studied. Moreover, the ability of the village economy to drive sustained growth through consumption needs to be analyzed.

Lowering the cost of energy through utilization of local resources and supporting the local economy to earn the wages to pay for the energy could be more feasible and sustainable means of driving growth in energy consumption, with the underlying assumption that growth in energy consumption is correlated with ability of the economy to grow. Hence, identification and development of DG projects in each Municipality can be a major strategy to achieve SE4ALL goals. Development of DG projects in rural areas contributes to high socioeconomic growth by providing capital injection, employment generation and associated economic activity, thus generating a ripple effect in the local economy in the longer term. DG is also considered as the best solution for reducing T&D system losses in a geographically disparate country like Nepal because it supplies local load while also providing reactive support to the system. Therefore, rather than viewing T&D extension and DG project development as competitive services; they could be developed as complementary services.

Enabling access to electricity in the most optimal and cost-effective method requires development of a T&D extension plan with consideration of most attractive DG projects. By undertaking T&D extension and DG development simultaneously through the most economically efficient & cost-effective method, all DG projects can be connected to the grid to benefit both the grid and the DG plants. Optimal grid extension plan incorporating DG development plan could provide the optimized, economically efficient, and the most cost-effective solution to the challenge of providing Sustainable Energy for All in 5 years. Therefore, technical and economic analysis of Transmission & Distribution (T&D) extension and Distributed Generation (DG) projects is deemed necessary. The rationale and principles of the project are discussed in detail in the next sub-section.

2.5 RATIONALE AND PRINCIPLES

Access to electricity has very high economic benefits. Electricity reduces human drudgery, enhances comfort, and enables safer and cleaner environment. It boosts productivity and economic activity, creates jobs, and facilitates delivery of education, health and government services. Energy services are critical ingredients of socioeconomic development; therefore, by appropriately subsidizing the development of DG resources to make it attractive to the private sector, GoN can deliver large economic benefits to the population and kick-start the local economy. Similarly, T&D network extension can also deliver large economic benefits as well as increase the sustainability of DG plants.

2.5.1 Access to the Grid Electricity for All (AGE4ALL)

Although grid extension to all Municipalities [i.e. Village Municipalities (VMs) and Town Municipalities (TMs)] is very capital intensive, it can deliver high economic benefits. The central grid can enable higher level of power and energy consumption, which could qualify as of Household electricity access – the highest level of energy access according to the Multi-tier Framework (MTF). T&D network extension, which entails development of T&D lines, hubs, and Substations to reach the Geographic and Demographic Centre (GDC) of Municipalities, alongside the development of DG projects, can decrease T&D losses and increase the reliability of the power system. The GDC locates the point within a Municipality, which is the best location to build a Substation to service all customers within the Municipality cost-effectively. This concept of 'Sustainable Distributed Generation and Grid Access to All' (SUDIGGAA) can act as a guiding principle for local governments to optimally utilize subsidies and scarce resources. SUDIGGAA has the potential to be a catalyst to electrify all local bodies within the county and economically exploit the local energy resources.

2.5.2 Distributed Generation (DG) as a Bidirectional Solution

The concept of Distributed Generation (DG) in each municipality advocates the Bottom-Up approach for identifying the best source of energy available locally considering the local population distribution and means of production. From a preliminary examination of the renewable energy resources available for electricity generation in the municipalities, it is evident that most of them have one or more renewable sources such as mini-hydro, solar, wind, or biomass available for development within their area, provided that the grid is available to balance the power by exporting the surplus and importing the deficit energy.

Therefore, DG development can be integrated with the Top-Down approach of T&D network extension from existing reaches of national grid to all the DG sources. This combination of Top-Down and Bottom-Up approaches will enable the expanding network to reach to all the municipalities of Nepal as well as provide the local means of income through Distributed Generation while comparatively reducing the demand on the central grid to completely supply all these areas. This approach has many other benefits. Hydropower DG plants can reduce Capital and Operational expenditure of Transmission and Distribution networks. Solar PV plants provide reactive support to the grid and decrease reactive losses. Additionally, they can service local loads and further reduce transmission losses of the grid.

2.5.3 DG and Grid Extension

The traditional approach to electricity generation has been to generate power through large central power plants and transmit this power to different load centers through the use of T&D network also known as the national grid. This approach often results in low cost of electricity generation; however, by the time this electricity reaches the end users located far away, the cost increases because of the additional costs and power losses incurred by the T&D network. Distributed Generation (DG) is an approach that employs small-scale technologies to produce electricity close to the end users of power. DG technologies often consist of modular renewable energy generators, which have a number of benefits such as lowering the cost of electricity, and increasing the reliability and security of power supply with fewer social and environmental consequences. Moreover, on-grid DG sources can use islanding techniques to serve the local distribution network even when the central grid is offline due to outages or load shedding.

Energy services are critical ingredients of socioeconomic development; therefore, by appropriately subsidizing the development of Distributed Generation (DG) resources to make it attractive to the private sector, GoN can deliver large economic benefits to the local population as well as kick-start the local economy. Similarly, T&D network extension, although capital intensive, can also deliver large economic benefits as well as increase the sustainability of DG plants. The central grid can enable higher level of power and energy consumption, which could qualify as the highest level of household electricity access according to the Multi-tier Framework (MTF). T&D

network extension, which entails development of T&D lines, hubs, and substations to reach the Geographic and Demographic Centre (GDC) of Municipalities, alongside the development of DG projects, can decrease T&D losses and increase the reliability of the power system. The GDC locates the point within a Municipality that is the best location to build a Substation to service all customers within the Municipality cost-effectively.

2.5.4 SUDIGGAA & Benefits

This concept of 'Sustainable Distributed Generation and Grid Access to All' (SuDiGGAA) can act as a guiding principle for local governments to optimally utilize subsidies and scarce resources. SUDIGGAA has the potential to be a catalyst to electrify all municipalities within the municipality and economically exploit the local energy resources. SUDIGGAA has many other benefits. Hydropower DG plants can reduce Capital and Operational expenditure of Transmission and Distribution networks. Solar PV plants provide reactive support to the grid and decrease reactive losses. Additionally, they can service local loads and further reduce transmission losses of the grid. Moreover, DG development and T&D extension can have ripple economic effect through forward and backward economic linkages.

The concept of Distributed Generation (DG) in each municipality advocates the Bottom-Up approach for identifying the best source of energy available locally considering the local population distribution and means of production. From a preliminary examination of the renewable energy resources available for electricity generation in the municipalities, it is evident that most of them have one or more renewable sources such as mini-hydro, solar, wind, or biomass available for development within their area, provided that the grid is available to balance the power by exporting the surplus and importing the deficit energy. Therefore, DG development can be integrated with the Top-Down approach of T&D network extension from existing reaches of national grid to all the DG sources. This combination of Top-Down and Bottom-Up approaches will enable the expanding network to reach to all the municipalities of Nepal as well as provide the local means of income through Distributed Generation while comparatively reducing the demand on the central grid to completely supply all these areas.

2.5.5 Equitable Viability Gap Funding and Limitation on Project Size

DG projects are a means of providing a sustainable source of income for the Municipalities in addition to being a delivery mechanism for equitable viability gap funding (VGF) to the Municipalities by the federal government. Since government resources are limited, the size of the projects will be limited according to the population of the municipality with preference to areas that are not yet served by the grid. As smaller projects cost more than larger projects due to economy of scale, the minimum size of the project shall be 500kW for hydropower projects. The

DG projects that are larger in size and commercially feasible and attractive for private sector will be selected by the local government to boost the local economy with help from federal Viability Gap Funding. Thus a preliminary higher limit of 1000 kW for hydropower projects are assumed for subsidized development. For other renewable technologies, the size and configuration of the DG projects are determined on the basis of providing the similar level of electricity service as provided by a 500 – 1000 kW hydropower project.

3 OBJECTIVES AND SCOPE OF WORK

3.1 OBJECTIVES

The overall objectives of this study are as following:

- Study all the 753 Municipalities and identify the optimum extension path of the T&D network to increase access to energy as well as integrate the proposed DG plants
- Find small-scale renewable sources of electricity generation in these municipalities that can be developed and operated in a sustainable manner with access to the grid
- Explore the economic and financial aspects of DG development and Grid extension including Viability Gap Funding (VGF) determination
- Prepare a Workable Plan for Sustainable Distributed Generation for Grid Access to All (SUDIGGAA)

3.2 SCOPE OF WORK

The scope of the study is as following:

- Optimum Grid Network Extension Program with the Single Line Diagram (SLD)
- **DG Project List**(maximum 3 projects) for each identified Municipality
- **Desk Study Report** for each Renewable Energy Technology
- **Economic and Financial Analysis** including estimates of required Investment and VGF

3.3 DELIVERABLES

The deliverables are as following:

- **Inception Report** identifying the Scope, Methodology and Work Schedule of the Study within 6 weeks (1.5 months)of the date of work award.
- **Interim Report** identifying the Summary of Sub-stations and a DG Project List within 8 weeks (2 months)of the date of work award.
- **Draft Report** within 15 weeks (3.5 months) of the date of work award on which NPC to provide comment within 1 week of submission.
- **Final Report** within 17 weeks (4 months) of the date of work award which shall contain the following:
- Report on T&D network extension to all identified Municipalities,
- Brief report of each identified Municipality assessing the Hydropower projects,
- Brief report for Solar projects classified by installed capacity,
- Brief report for Biomass (or Biomass-Solar hybrid) projects classified by installed capacity.
- General report for Wind power identifying feasible areas, opportunities and challenges.

- Conclusion and Recommendations identifying the most optimal energy development scenario.

3.4 LIMITATIONS OF THE STUDY

The limitations of the study are as following:

- The project size-range is limited to 500 – 1000 kW for hydropower projects. For other renewable technologies, the size-range of the DG projects will be determined on the basis of providing the same level of electricity service as provided by a 500 – 1000 kW hydropower project.
- All project cost, efficiency, and power generation values are determined by extensive research and consultation with Renewable Energy (RE) experts. Nonetheless, due to the novel nature of some RE projects (solar, biomass, and wind), the cost figures might quickly fluctuate with time.
- Due to a large volume of projects and paucity of time, field-visit to each individual site is not possible. Nonetheless, coordination meeting and 'District Coordination Committee' level consultation will be carried out at the district level. Further study for verification of the input parameters and output indicators for each site is necessary.
- Time available for this economic and financial study of 753 Municipalities is very short, and further studies such as detailed feasibility study, and detailed engineering design along with site investigation are required to examine each site in detail.

4 METHODOLOGY

4.1 SUMMARY OF OVERALL METHODOLOGY

The overall methodology of this study is presented technology-wise in the next sub-section. The overall methodology of the project is presented step-wise below.

Step 1: Grid extension:

- Criteria is created to find sites for Substations and the alternate paths of the grid extension.

Step 2: DG hydropower projects:

- Criteria is created to screen and find max. 3 best alternative sites.

Step 3: DG Solar PV, Wind Power, Biomass (or Biomass-Solar hybrid) projects:

- Criteria is created to screen and find the best site.

Step 4: District Field Visit

- Findings are corroborated through district level site visit.

Step 5: Financial Analysis of DG projects

- Financial analysis is performed to find the best site and determine the necessary investment and VGF amount.

Step 6: Technical and Cost Analysis of Grid Extension

- Technical analysis of grid extension is performed with consideration of selected DG sites to find the best grid extension path.
- Cost analysis is done to determine the investment necessary for grid extension.

Step 7: Economic Analysis

- Province-wise Economic analysis is performed to determine the feasibility of Grid extension WITH DG development vs. Grid extension WITHOUT DG development

Step 8: Workshop and Comments

- Feedback and comments on draft report findings are taken from NPC
- Stakeholder workshop is organized to disseminate findings of the study, and receive feedback and comments
- Final report with findings is prepared incorporating comments and submitted to NPC

4.2 TECHNOLOGY WISE METHODOLOGY

4.2.1 Grid Network Extension

Transmission & Distribution (T&D) network extension planning requires high capital cost investments. Moreover, network planning and extension must be performed simultaneously with DG project planning, such that DG projects can be connected to the central grid for effective power balancing. The processes, assumptions, criteria, software and tools, and economic analysis used for determining the T&D network extension are discussed in detail herein.

4.2.1.1 Process, Assumptions, Criteria and Tools for Screening

The following are the processes followed, the assumptions made and the criteria selected for T&D network extension:

- Study and compilation of the available data of all the existing NEA sub-stations and proposed sub-stations of NEA in different areas of Nepal in coordination with relevant NEA experts.
- Study energy and power demand forecasts and extrapolation of the population data of Nepal.
- Find the Geographic and Demographic Centre (GDC) of identified Municipalities, which locates best site to build a Substation to grid-connect and service all customers within the Municipality. GDC is determined using a Weighted Centroid Formula, which uses VDC population, and the distance of different VDC's within a Municipality from the geographical center as inputs.
- Propose a new Substation at the GDC of each identified Municipality, if existing Substation is not present already within the Municipality.
- Identify alternative paths for extension of T&D network to these proposed Substations using Kruskal's Algorithm.
- Develop a MS Excel-based 'T&D Economic Model' and find the Optimum Grid Network Extension Plan.
- Perform a detailed load flow analysis of T&D network extension by using the relevant network analysis design software.

4.2.2 Hydropower Projects

While selecting hydropower projects, it is necessary to optimize the hydrological potential of the river. Therefore, projects with higher potential at a given probability of exceedance have been avoided; which means that large river sites have been excluded from the study. Moreover, areas that are already ear marked by the government for license have also been excluded. Similarly the projects reserved by government in its ‘basket’ have also been removed in this study. For avoidance of disputes and for simplicity, overlap areas between local bodies have not been selected until search for other sources are exhausted. These processes, assumptions, criteria, desk study outputs, software and tools, and economic analysis used for site selection are discussed in detail herein.

4.2.2.1 Process, Assumptions, Tools &Criteria for Site Screening

The following are the processes followed, the assumptions made, tools used, and the criteria selected for DG Hydropower site screening:

- Large rivers of Nepal with large catchment area and potential of more than 1 MW have been excluded in this study.
- Project sites with long waterways (L>4 km) have been excluded.
- Rivers with discharge more than 5 m3/s at 65% probability of exceedance have not been included in the study
- In general, Projects sites have been avoided for head less than 40 m.
- The total Head loss in waterways is assumed as 10% of the gross head available from Intake to Powerhouse and overall Efficiency of the system is assumed as 85%.
- ‘QGIS’ and ‘Google Earth ‘software for the estimation of catchment area, and ‘Local Climate Estimator’ (LocClim) software have been used for the estimation of precipitation data.
- Hydrological analysis has been carried out using ‘Hydest’/ ‘Modified Hydest’ model and the available database up to 2006 for the estimation of discharge provided by Department of Hydrology and Meteorology (DHM). Accordingly, the design discharge has been estimated as an average of these three approaches.
- Sites where grid-connected Hydropower is already constructed/ is under construction/ has received license/ has applied for license/ or has been put in ‘basket’ from Department of Electricity Development (DoED) have been excluded.
- Alternate sub-stations and T&D network extension paths have been taken into account to locate the potential sites closer to major load centers and GDC of the Municipality.
- Cost estimates of all the identified hydropower projects have been determined using a hydropower study model developed during the study. General standard template has been developed and data is presented in uniform manner in a standard report format. Salient features, relevant maps, available/design flow discharges, and probability of exceedance data for each project have also been presented. Cost of the projects has been gathered through regular coordination with the experts in the hydropower sector.
- Since the direct flow measurement data at the proposed hydropower sites are not available, flow data have been transposed at proposed intake site, by the use of observed gauge station’s river flow data, published by the Department of Hydrology and Meteorology (DHM).The identification of hydropower site is completely based on desk study. However district level coordination/consultation meetings have been conducted in each District Coordination Committee’s office to the possible extent in order to gather the important information about the identified projects.

4.2.2.2 Desk Study of DG Hydropower

Desk study for DG Hydropower comprised of the following:

- Detailed study of the all available topographical maps of Nepal.
- Locate all completed and under-construction Hydropower projects of Nepal.
- Locate Hydropower projects with issued and applied licenses.
- Find relevant sites other than the above pre-identified sites which have been excluded in the present study
- Collection of all relevant information such as digital maps, existing and planned electrical network information, population data, and GIS data such as road and water network.

4.2.2.3 Software and Tools

The following software/ templates/ tools have been used for the design, screening and ranking:

- 'QGIS' and 'Google Earth' for digitizing the works.
- 'Hydest Model' and 'Modified Hydest Model' for the estimation of design discharge.
- 'LocClim' software for the estimation of precipitation data.
- 'Standard Data Collection Sheet' has been developed for data collection.
- MS Excel-based 'Hydropower Studio Model' has been used to determine hydropower parameters for selection of best three sites. These hydropower parameters received from this model for these sites have been used as an input into the MS Excel-based 'Economic and Financial Model' to rank and find the best three Hydropower DG sites.
- All the identified sites have been prepared and presented in a Country Map of Nepal by the use of Information and Communication Technologies (ICT) to the extent possible.
- For the Design of Solar PV System, PVSyst 6.64 version has been used.

4.2.3 Solar PV Projects

Feasibility of Solar Photovoltaic (PV) projects is heavily dependent on solar irradiation data for the site. Moreover, compared to hydropower projects, Solar PV projects require larger area to provide the same level of electricity service. Literature and experience shows that when hydropower potential (adequate discharge and head) are available locally, and transportation and labor costs are low, DG Hydropower sites are the best available technology (BAT) for most cases due to high Plant Load Factor (PLF) compared to other RETs. Nonetheless, in absence of hydropower resources, solar energy can be used effectively to fulfill daytime demand. These processes, assumptions, criteria, desk study outputs, software and tools, and economic analysis used for Solar PV site selection are discussed in detail herein.

4.2.3.1 Process, Assumptions, Tools & Criteria for Site Screening

The following are the processes followed, the assumptions made, tools used, and the criteria selected for DG Hydropower site screening:

- The proposed solar sites have been located mostly in the Terai Region. For Hilly Region, proposed solar sites have been considered when the Capital Cost per kW and the Levelized Cost of Electricity (LCOE) is too high.
- Project sites where grid-connected Solar PV is already constructed, is under construction, has received license or has applied for license from Department of Electricity Development (DOED) have been excluded.
- Solar power plants have been located within 2 km radius from NEA's Existing Sub-stations or the Sub-stations proposed by this study to reduce transmission costs and losses.
- If available, Barren/ Arid land have been used for proposing site location using the Land-Use Map of Nepal. Conservation areas, Forest areas, shading areas, and areas with large obstacles have been avoided and sites with easy road accessibility are given preference.
- Most of the solar sites are located in the Terai. The simulation of solar projects has been carried out in PVSyst for three different locations in Terai namely, Jhapa, Chitwan and Kailali. For all these locations, three different plant sizes of capacities 250kWac, 500kWac and 1MWac has been simulated. Apart from this, 1MWac Solar PV Project has been modeled in Mustang,Jumla and Khotang also. The major difference would be for different locations would be solar radiation data. This study consider that the modeling carried out for 6 different locations namely Jhapa, Chitwan, Kailali, Mustang,Jumla and Khotang would be enough to cover the whole country as the irradiance data of other locationswould also resembles with these locations.
- The irradiance data used for designing project is Metronome hourly data which is stipulated of 1991-2010 time series data at a horizontal resolutions of 8km.
- Solar all of these large scale Solar Projects, Probability Index of P50 (50%) has been considered to find out specific energy yield at given locations.
  - Similarly P_{DC}/ P_{AC} ratio of designed projects ranges between 1.1 to 1.3. Similarly Capacity Utilization Factor (CUF) ranging between 18.63% to 22.36%. The lowest CUF has been observed at eastern hill site (Khotang site) and highest at western hill (Jumla site) which is very attractive for commercial viability of the projects.

- The performance ratio (PR) obtained from all of designed projects in six different locations are more than 80% which indicates well designed projects. According to Utility Scale Solar Photovoltaic Power Plants, A Project Developers Guide developed by IFC says that PR for well designed projects ranges between 77-86%.
- For the Land Use planning for Solar PV project, a maximum of 20m^2/kWphas been considered. In average it requires 15m^2/kWp area of land in Nepal of Solar PV.
- Data have been gathered through regular coordination with the experts in the Solar PV Sector.

4.2.3.2 Desk Study of DG Solar PV

Desk study for DG Solar PV comprises the following:

- Detailed study of the all available topographical maps of Nepal.
- Locate all completed and under-construction Solar PV project^s of Nepal.
- Locate Solar PV projects with issued licenses and that have applied for a license.

- Collection of all relevant information such as solar irradiance data, digital maps, existing and planned electrical network information, population data, and GIS data such as road and water network.

4.2.3.3 Software and Tools

The following software/ templates/ tools have been used for the design, screening and ranking:

- Solar Irradiance Data (Global Horizontal, Diffuse, Direct Normal Irradiance and Clearness Index) shall be obtained from "NASA SSE", "Global Solar Atlas", "Solargis", "Meteonorm" or a combination of these data sources.
- Temperature data have been collected from local weather stations or satellite based dataset.
- 'PVSYST' software, MS Excel-based 'Solar Sizing Model' or a combination of both have been used for sizing of the individual project.
- MS Excel-based 'Economic and Financial Model' have been used to calculate the economic indicators of the best DG Solar PV site in each identified Municipality.
- 'Standard Data Collection Sheet' has been developed for data collection.

4.2.4 Biomass (or Solar PV hybrid) Projects

Biomass or Waste-to-Energy projects require large amounts of biodegradable waste which is converted into biogas and finally into electricity using a gas turbine. Therefore, it is important to locate Biomass projects near the waste disposal area of the municipality. Biomass projects also require considerable project area of which the roof area could be utilized to install Solar PV modules given the site conditions is ideal. For such a hybrid Biomass-Solar plant, the daytime demand can be met with Solar PV, and during other periods the demand can be met from Biomass plant which can be operated on demand. These processes, assumptions, criteria, desk study outputs, software and tools, and economic analysis used for site selection are discussed in detail herein.

4.2.4.1 Process, Assumptions, Tools & Criteria for Site Screening

The following are the processes followed, the assumptions made, tools used, and the criteria selected for DG Biomass (or Solar PV hybrid) site screening:

- Priority has been given to Biomass projects sourcing raw materials from companies/ organizations, which have direct ownership of the Government of Nepal. Municipal waste and sewerage facilities are taken into consideration for the design analysis. Priority has been given in the Metropolitan City, Sub Metropolitan City and Large Municipalities.
- Project sites where grid-connected Biomass is already constructed, is under construction, has received license or has applied for license from Department of Electricity Development (DOED) have been excluded.
- If available, Barren/ Arid land has been used for proposing site location using the Land-Use Map of Nepal within 2 km radius of Waste Disposal/ Dumping site.

- Plant size has been calculated based on the population density and size of the local population. Population data for 2017 has been extrapolated from the 2011 BS Census of Nepal and the average waste generation per capita has been considered as 0.32 kg/ day.
- Environmental aspects of the biomass plants have also been considered during analysis. Compensation from the Municipality for waste treatment and the potential benefit from the bi-product (fertilizer) have been taken into account for economic analysis.
- In the plains, hybrid of Biomass and Solar PV have been considered in such a way that daytime load is served by solar and nighttime load is served by Biomass.
- Data havebeen gathered through regular coordination with the experts in the Biomass Sector.

4.2.4.2 Desk Study of Biomass (or Solar PV hybrid)

Desk study for Biomass(or Solar PV hybrid) comprises of the following:

- Detailed study of the all available topographical maps of Nepal.
- Locate all completed and under-construction Biomass projects of Nepal.
- Locate Biomass projects with issued licenses and that have applied for a license.
- Collection of all relevant information such as Municipal solid waste management plan, digital maps, existing and planned electrical network information, population data, and GIS data such as road and water network.

4.2.4.3 Software and Tools

The following software/ templates/ tools have been used for the design, screening and ranking:

- 'QGIS' and 'Google Earth' for area calculation of Municipality.
- MS Excel-based 'Biogas Model' developed by the AEPC have been used to calculate the size and area requirement.
- MS Excel-based 'Economic and Financial Model' has been used to calculate the economic indicators of the best Biomass site in each identified Municipality.
- 'Standard Data Collection Sheet' has been developed for data collection.
- PVSyst 6.64 for designing Solar PV Projects

4.2.5 Wind Power Projects

Although some study/installation of wind projects have been made in Nepal through the "Solar Wind Hybrid Project" by AEPC in consultation with RET sector experts, the possibility of promoting wind energy has many challenges such as transportation of turbines, or sufficient wind power potential. Therefore, the potential areas for wind power generation in Nepal have been identified in the report and major challenges and opportunities have been summarized accordingly. The wind power plant is feasible only if there is a uniform speed of wind throughout any time of the year. When compared with its other counterparts, wind electricity is quite expensive but in places where there are no hydropower sources and for the sake of diversity in power generation, wind power can be installed.

4.2.5.1 *Process, Assumptions, Tools & Criteria for Site Screening*

The following are the processes followed, the assumptions made, tools used, and the criteria selected for Wind Power site screening:

- The selected sites should have uniform wind speed throughout the year.
- The selected site should have open space without any obstruction (towers, trees, etc.) and leveled land structure as much as possible. Wind plants can also be installed along the roads or highways provided there is sufficient clearance.
- The total wind power potential for the proposed site should be sufficiently larger than the size of the proposed wind power station.
- The initial wind speed data was taken from the SWERA Report, July 2008, prepared by Alternative Energy Promotion Centre (AEPC).
- Using the computer software GOOGLE EARTH PRO and the coordinates of the site obtained from the SWERA report, proper site was selected for wind power station. A certain area was then marked on the same software which was the exact location for installing the power station. The two out of three proposed wind power site are located in Mustang District and remaining one is in Okhaldhunga district.
- There are no existing substation near the two sites at Mustang but the proposed substation is at distance of about 36 km and 45 km from the proposed substation at Annapurna Gaunpalika of Myagdi district. Similar is the case of site at Okhaldhunga.

4.3 DISTRICT FIELD VISIT AND CONSULTATION

Due to a large volume of projects and paucity of time, field-visit to each individual site was not possible in this study. Nonetheless, coordination meeting and 'District Coordination Committee' level consultation have been carried out at the district headquarter for the verification of identified sites and to gather related information. Total 16 numbers of field team have been mobilized for different districts. Some of the teams have completed the assigned field task and some teams are still in the field. The district level consultation seems to be important to gather first hand information about the proposed projects and to identify unique local conditions and its effect on assumptions made for the screening and selection of projects.

The list of teams mobilized for the district level consultation is as under:

Table 2 : List of teams mobilized

Team No:	Team Members	Districts	Remarks
Team 1	1. Ranju Pote (GIS) 2. Abin Prajapati (GIS)	1. Taplejung, 2. Panchthar, 3. Ilam, 4. Jhapa, 5. Sunsari and 6. Morang	Team Returned
Team 2	1. Prasan Lama 2. Amir Bhandari	1. Bhojpur, 2. Terhathum, 3. Sankhuwasabha, 4. Dhankuta	Team Returned
Team 3	1.Ishwor Sapkota (GIS) 2.Jagadish Poudel (GIS)	1. Solukhumbu, 2. Okhaldhunga, 3, Khotang and 4. Udayapur and 5. Sindhuli	Team Returned
Team 4	1.Bishnu Dawadi 2. Tek Raj Subedi	1. Dolakha, 2. Ramechhap, 3. Sindhupalchowk and 4. Kavreplanchowk	Team Returned
Team 5	1.Niraj Sah (Hydro) 2. Saurav Suman (Hydro)	1. Rasuwa, 2. Nuwakot, 3. Dhading, 4. Lalitpur, 5. Bhaktapur, 6. Kathmandu	Team Returned
Team 6	1. Himal Chand (GIS) 2. Bijaya Aryal (GIS)	1. Gorkha, 2. Lamjung, 3. Manang, and 4. Tanahun and 5. Kaski	Team Returned
Team 7	1.Khimananda Kandel 2.Jagan Nath Ammay (Hydropower Engineer)	1. Mustang, 2. Myagdi, 3. Baglung and 4. Parbat	Team Returned
Team 8	1. Nabin Panta 2.Bibhav Pokharel	1. Syangja, 2. Palpa, 3. Gulmi, 4. Arghakhanchi and 5. Nawalparasi, 6. Rupandehi and 7. Kapilvastu	Team Returned

Team 9	1. Binod Karki (Hydro) 2.Ramesh Kandel (Hydro)	1. Pyuthan, 2. Rolpa, 3. Rukum and 4. Salyan and 5. Dang	Team Returned
Team 10	1. Abanish Tiwari (Electrical) 2. Tika Ram Regmi (Electrical) 3. Ravi Raj Shrestha (Electrical) 4. Binay Poudyal (Electrical)	1. Jajarkot, 2. Surkhet 3. Dailekh 4. Dhanusha 5. Saptari 6. Mahottari	Team Returned
Team 11	1. Bishnu Dawadi 2. KishorKarki	1. Kalikot, 2, Jumla and 3. Mugu.4. Banke and 5. Bardiya	Team Returned
Team 12	1.Suraj Upadhyay (GIS) 2.Asutosh Bhandari (GIS)	1. Humla and 2. Dolpa	Team Returned
Team 13	1.Yurosh Sapkota (GIS) 2. Sujan Nepali (GIS)	1. Dadeldhura, 2. Doti, 3. Achham and 4. Bajura	Team Returned
Team 14	1. Pravakar Khanal (GIS) 2. ShaligramLamsal (GIS)	1. Bajhang, 2. Baitadi, 3. Darchula, 4. Kailali, 5. Kanchanpur	Team Returned
Team 15	1.Anushka Adhikari 2. Amreet Karki	1. Rautahat, 2. Bara, 3. Parsa, 4. Makwanpur and 5. Chitwan	Team Returned

4.4 FINANCIAL ANALYSIS

After identification and screening, of DG RET projects through Technical Analysis (Desk Study Report) explained in previous sub-sections, Financial analysis has been performed to identify the best DG project in each identified Municipality to aid the local government and private sector in implementation of these projects. The Financial analysis has been performed by discounting the time-series data of the Capital Cost, Operations & Maintenance (O&M) Costs, and Income from sale of electricity to NEA over the Project lifetime. An appropriate Discount Rate, Loan Interest Rate, and Bank Loan Repayment Period have been selected to perform the financial analysis. Since financial analysis is performed from the private sector's perspective, the costs of Royalty, Customs, Taxes, Cost of Debt, and Cost of Equity are taken into account. Viability Gap Funding (VGF) necessary from the government for each project is determined using Financial Analysis, with the assumption that the VGF makes the Return on Investment (Equity) around 15%.

4.5 ECONOMIC ANALYSIS

After finding the best DG and Grid Extension Scenario from Financial Analysis, Economic Analysis was performed Province-wise for two scenarios:

4.5.1.1 Grid Extension to all Municipalities WITH the DG sources

The Costs of Grid Extension and selected DG projects are calculated. The energy consumed in the system is estimated for Electrified, Partially Unelectrified, Partially Electrified, and Unelectrified Municipalities. The difference of energy between the total load demand and energy supplied from DG plants has been assumed to be supplied from Central Hydropower Plants with 60% PLF. The System losses of bottom-up DG architecture are estimated at 9%. Benefits are calculated on the basis of Fuel Replacement in Unelectrified areas and Willingness to Pay in Electrified areas. These assumptions are summarized in Annex L.

4.5.1.2 Grid Extension to all Municipalities WITHOUT the DG sources

The Grid extension costs are calculated and electrical load flow analysis indicates that the Cost of Grid Extension with DG is lower than that of without DG. Comparatively, lower capacity lines and substations are necessary to deliver electricity access when DG sources are available due to improvement in Grid Voltage and Performance. The total load demand has been assumed to be supplied from Central Hydropower Plants with 60% PLF. The System and Reliability losses of traditional top-down energy architecture are estimated at 18%. The energy consumed in the system is estimated for Electrified, Partially Un-electrified, Partially Electrified, and Un-electrified Municipalities. These assumptions are summarized in Annex L.

A discounted Cost-Benefit Economic Model is used to perform economic analysis from the perspective of the government with appropriate Economic Discount, Capital Cost per kW

(NPR/kW) for DG projects, Capital Cost per kW (NPR/kW) for Central Plants, and O&M Cost per Year (%). As the analysis was performed from the perspective of the Government, All Cost parameters were calculated excluding the applicable VAT and Customs duty charged by the government. The estimated values are presented in Annex D.

4.6 WORKSHOP

Workshop has been conducted in Kathmandu by inviting the leading RE experts in the sector. The purpose of the workshop is to receive comments and feedback from the invitees and participants. The workshop serves as an important step in verification of preliminary results. Moreover, the workshop also serves as a dissemination tool to inform the participants about the preliminary results of the project.

A second Workshop has been conducted in Kathmandu with participation of experts, stakeholders at the decision making level, and sectoral experts of political bodies. The workshop intended to inform and illuminate on the findings of the study and the pathway to its logical conclusion which is the implementation of the Distributed Generation and Grid Access expansion propositions.

5 MODELLING &ASSUMPTIONS

5.1 HYDROPOWER

5.1.1 Approach for Cost Estimation

Following approach have been made for the estimation of cost estimation. Length of headrace, penstock, distance from existing or proposed substation, nearest road head and distance of sand availability was found out by using GIS Map, Google Earth and available maps. Approximate design/sizing of headrace, desanding basin, forebay and penstock pipe (diameter and thickness) is made for the identified alternatives.

- 11 kV or 33 kV transmission line is proposed for power transmission and unit cost of 11 kV and 33 kV transmission line is prepared by including the cost of switching station.
- Water to wire cost is taken as lump sum rate as per kW in dollar.
- It is assumed that the main construction materials and equipments will be delivered from nearest stations namely; Birtamode, Itahari, Mirchaiya, Bardibas, Hetauda, Narayangadh, Kathmandu, Pokhara, Butwal, Bhaluwang, Tulsipur and Atariya.
- Government standard has been followed for the estimation of rate of material. For generalizing the study, the rate of materials at Baglung district is taken as base rate and rate has been increased by certain percentage for remote districts with remoteness factor provision in cost estimate model.
- For remote districts like Humla, Dolpa and Mugu provision for transportation by air is also considered.
- Revenue estimation for July to November, tariff rate is taken as Rs. 4.8 / Unit and for December to June Rs. 8.4/Unit is considered. Tariff rate for revenue generation is increased by 3% per annum for 8 consecutive years and after this the tariff rate is fixed as constant as per the NEA tariff provision for small hydropower projects.
- Insurance is taken as 0.3% annually of total project cost. Royalty is taken as per the hydropower policy of Nepal.
- Financial parameters have been presented for all investment and equity investment options.
- Hydropower project is compared with Solar power plant by using Least Cost of Energy (LCoE) mehtod.
- Physical contingencies for Civil, Electro Mechanical (Water to Wire), Penstock/Hydro mechanical are taken as 10%, 2.5 % and 5% respectively. Similarly VAT/Tax is taken as 13% and in case of Electromechanical items (Water to Wire) tax is taken as 1%.
- Brief Summary report has been generated by using Hydropower Studio Model.

5.1.2 Hydropower Studio Model

Hydropower Studio Model is basically a Microsoft Excel Application designed for finding the summary report of mini hydropower projects ranging for up to 1 MW installed Capacity. This model is developed by Civil Engineer Khimananda Kandel (khimanandakandel@yahoo.com) and applied for this study.

Most of the inputs in this models are derived by using available topographical maps, GIS Maps , Google Earth or the similar map tools for finding out the location of the project, intake and powerhouse coordinates, gross head, length of headrace alignment, length of penstock alignment, distance from road head, distance from available or proposed grid, distance of available sand location, river basin name, supply center etc. Precipitation data are estimated by using LocClim software. The rate of materials at particular locality is to be given as input.

With the above inputs, the model carries out the following estimations as inbuilt tools.

- Hydrological Analysis is estimate as an average of Hydest, Modified Hydest and DHM Database Based New Model
- Switching Option for Q45, Q65 and Q80 is available.
- Design Automation for Headrace (Canal/Pipe), Desanding Basin, Penstock (Dia and Thickness) is made.
- Bill of Quantities and Cost estimates is prepared.
- Approximate Sizing of Electrical Equipment’s is made.
- Automation of Transportation Distances is made from 13 base stations.
- Rate inputs for main construction materials can be entered as input.
- Revenue Generation is estimated as per NEA PPA Provision.
- Financial Analysis is carried out for all project cost versus equity investment.
- LCOE comparison for Hydro and Solar project options.
- Comparison of Different Hydropower Alternatives can be made by using this model.
- Reviewing of the Feasibility Study and Detailed Feasibility Study reports can also be made.
- This model generates brief summary report.
- This model is User Friendly and Useful Planning Model for projects of this range.

The manual for this model can be downloaded from the website of NEA Engineering Company and Water and Energy Consultant's Association Nepal (WECAN) (wecan.org.np). The copyright of the this model is reserved in the developer.

5.1.3 Web Based Platform for Hydropower and Energy Development

Web Based Platform for Hydropower and Energy Development model with the website nhydro.softwel.com.np is a GIS based software under development by Abhiyan Consultancy Pvt. Ltd., New Baneshwor, Kathmandu with the support of NEAEC. This software is designed by Er. Prashant Malla, Senior Civil Engineer and Dr. Akhilesh Kumar Karna and the team from which the hydrological estimation of the particular river point can be made by using the Hydest Method, Modified Hydest Method and the DHM data base new Model.

In this software, following inputs are made.

- Picking the river intake point either by clicking on the proposed intake or by giving the coordinate of the proposed intake in Lattiute, Longitude format.
- By clicking on the Get Catchment option, the hydrology of the particular intake is generated and can be downloaded.
- Catchment area of the proposed intake site (Total, below 5000 m and below 3000 m) is generated automatically.
- It also generates the hydrological estimates by using Hydest, Modified Hydest and DHM base model.
- In the model, Desanding Basin, Forebay and Powerhouse can also be marked.
- This model also generates the coordinates of intake and powerhouse.

The manual for this model can be downloaded from the website of NEA Engineering Company, and the website of Abhiyan Consultancy Pvt. Ltd. . The copyright of the model is reserved in the developer.

5.1.4 Limitations

- As per the ToR, it is to identify and study the potential hydropower sites of installed capacities 500 kW to 1 MW. So, the hydropower sites with more installed capacities are not included in this study.
- The project sites have been identified for 65% probability of flow exceedance. There is even the possibility of finding more sites with lower Probability of flow exceedance. i.e., there is possibility of sites to be found out in river basins at 45% probability of flow exceedance.
- It was not possible to make site visit for the verification of power output at this stage of study. So, in future, site verification of the projects and further stages of study needs to be made before the implementing the hydropower projects.

5.2 SOLAR PV

5.2.1 Assumptions

- The proposed solar sites have been located mostly in the Terai Region. For Hilly Region, proposed solar sites have been considered where hydropower sites are non-existent or when the Capital Cost per kW and the Levelized Cost of Electricity (LCOE) of identified hydropower projects is too high.
- Solar power plants have been located within 2 km radius from NEA's Existing Sub-stations or the Sub-stations proposed by this study to reduce transmission costs and losses.
- If available, Barren/ Arid land have been used for proposing site location using the Land-Use Map of Nepal. Conservation areas, Forest areas, shading areas, and areas with large obstacles have been avoided and sites with easy road accessibility are given preference.
- Most of the solar sites are located in the Terai. The simulation of solar projects has been carried out in PVSyst for three different locations in Terai namely, Jhapa, Chitwan and Kailali. For all these locations, three different plant sizes of capacities 250kWac, 500kWac and 1MWac has been simulated. Apart from this, 1 MWac Solar PV Project has been modeled in Mustang, Jumla and Khotang also. The major difference would be for different locations would be solar radiation data. This study consider that the modeling carried out for 6 different locations namely Jhapa, Chitwan, Kailali, Mustang, Jumla and Khotang would be enough to cover the whole country as the irradiance data of other locations would also resembles with these locations.
- The irradiance data used for designing project is Meteonorm hourly data which is stipulated of 1991-2010 time series data at a horizontal resolutions of 8km.
- Solar all of these large scale Solar Projects, Probability Index of P50 (50%) has been considered to find out specific energy yield at given locations.
- Similarly P_{DC}/ P_{AC} ratio of designed projects ranges between 1.1 to 1.3. Similarly Capacity Utilization Factor (CUF) ranging between 18.63% to 22.36%. The lowest CUF has been observed at eastern hill site (Khotang site) and highest at western hill (Jumla site) which is very attractive for commercial viability of the projects.
- For the Land Use planning for Solar PV project, a maximum of 20m2/kWp has been considered. In average it requires 15m2/kWp area of land in Nepal of Solar PV. Transport costs are calculated based on land or air transport according to volume (m.cu.) or weight (tons) of goods as quoted by Pashupati Cargo & Export Services Pvt. Ltd.

5.2.2 Approach for Cost Estimation

- Following approach have been made for the estimation of cost estimation.
- Based on solar irradiation maps (SolarGIS and Meteonorm data) and transport costs (Taken from Pashupati Trade), the Country has been divided into six unique regions namely East Terai, East Hill, West Terai, West Hill, Remote West Hill, and Very Remote West Hill, which are tabulated in the Annex F and shown in Figure 22. Six representative sites in these regions (namely Jhapa, Chitwan, Kailali, Mustang, Jumla and Khotang)are modeled in

PVSYST software to obtain the Capacity Utilization Factor and technical performance indicators.

- The performance ratio (PR) obtained from all of designed projects in six different locations are more than 80% which are indicative of well-designed projects, according to “Utility Scale Solar Photovoltaic Power Plants: A Project Developers Guide” developed by the IFC, which stipulates that the PR for well-designed projects ranges between 77 and 86%.
- Cost has been estimated for turn-key project development of 1 MWac (1000 kWac) including the costs of the Solar PV Panels, Grid Interactive Battery Storage Inverter, Battery Bank, Battery Charge Controller, Electrical Cables and Connecters, Switchyard, Transmission Lineup to the nearest Substation, Land Acquisition or Lease, Transport Costs, and other Miscellaneous items. The schematic representation of the Solar PV site is shown in Figure 23.Battery Storage for the 1 MWac Solar plant is considered for 1 hour of Peak Lighting Load at 50% Lighting load factor to reach at 500 kWh of storage.
- Battery Storage was considered for Solar PV to justify its comparison with other technologies such as Hydropower and Biomass, by configuring the Solar PV plants to have similar levelof electricity service to that of other technologies (such that smooth operation during nights or peak load is possible in case the central grid is down). Then Costs per kW and CUF are calculated for the 6 regions mentioned above, which are presented in Annex F.

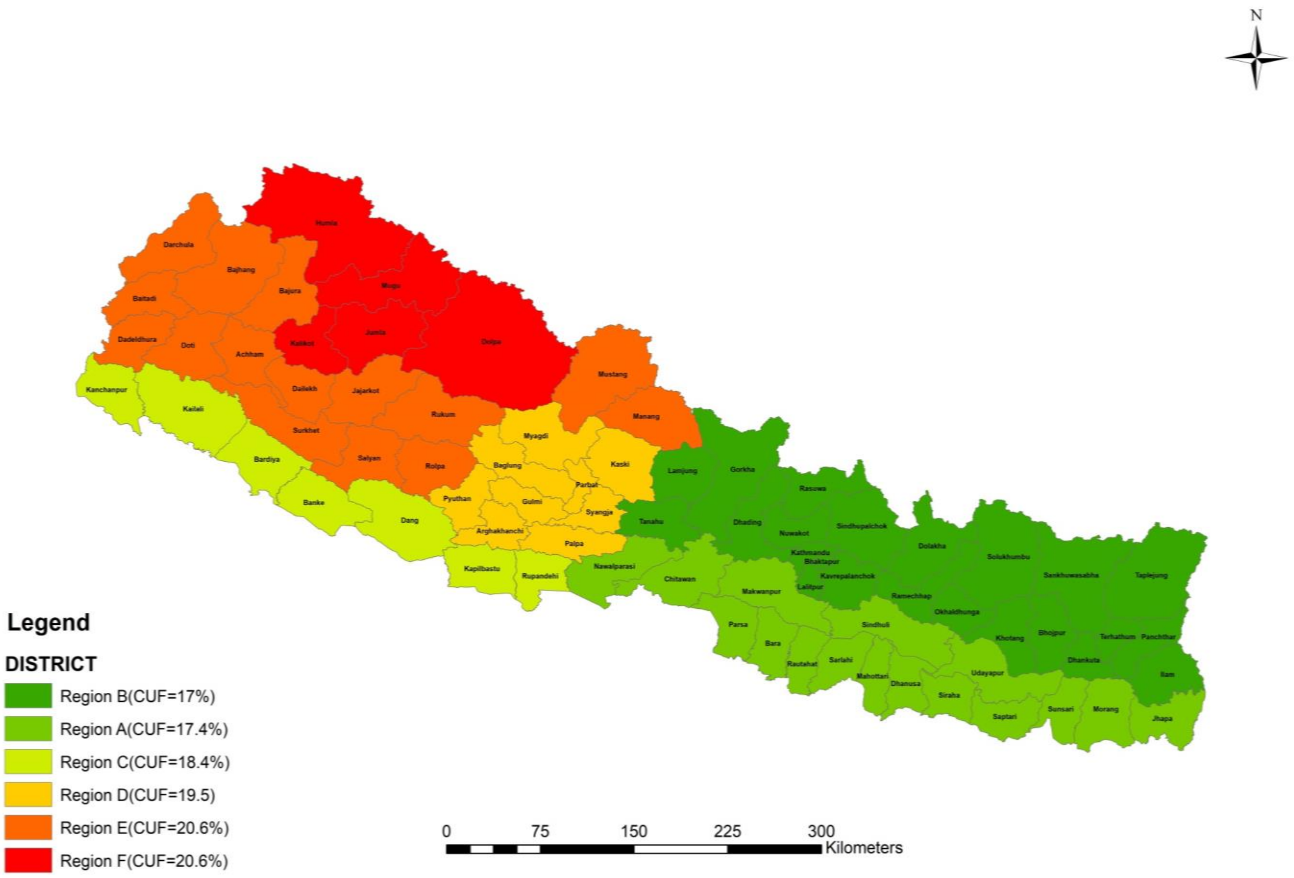

Figure 22 : Division into six regions according to CUF and Transport Costs

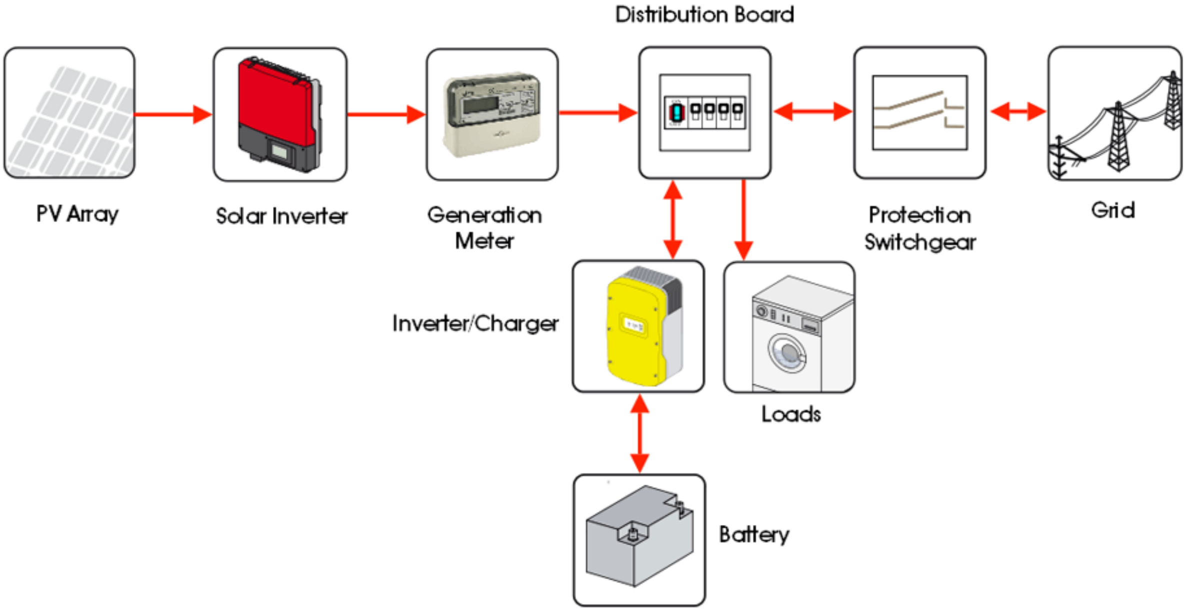

Figure 23 : Schematic representation of Solar PV with Battery

5.2.3 Limitations

- As the CUF and Transport Costs are estimated for 6 regions, there could be some discrepancies in these values for each individual site. Nonetheless, these discrepancies would be minimal.
- Due to limitation on the project size, maximum of 1000kWacof Solar PV installed capacity have been considered for each Municipality.
- Cost estimation have been performed for 1000 MWac Solar PV plant and economy of scale has been ignored to estimate the costs of 250 kWac and 500 kWac plants. Increase in price of smaller plants due to economy of scale would be minimal due to modular nature of Solar PV plants.

5.3 BIOMASS

Two types of projects are considered one with agriculture waste and another with municipal waste and considered both with waste to energy. Following general assumptions are made in this study

- Only rice husk is considered as agriculture waste, however other waste has also equal potential for energy extraction. One metric ton of rice will produce 220kg of rice husk and 1 metric ton rice husk can produce 410kwh energy. For Rice husk Gasifier technology is considered with the product of energy and silicate.
- Major Rice production area is considered and district wise analysis is performed and the available waste for power generation is assumed to be 25%.
- The municipal waste generation is 0.32kg /person /day and among which 60% is organic waste and this organic waste is used to produce methane through anaerobic digestion process, with the product of energy and fertilizer.
- Size of projects are considered with minimum of 12 hours operation per day. In case of Hybrid with solar day time energy supplied through solar and remaining with biomass.
- One football ground area (110mX90m) is considered for 1 MW power generation (European practice), which include compost processing also.

5.3.1 Limitations

- The ToR of the study it to propose the potential sites of installed capacities 500 kW to 1 MW. So, the sites with bigger capacity is considered for 1 MW and if it is less than 500kw hybrid combination with solar is proposed , project less than 200kw are not considered in this study.
- The project sites have been identified for 24 hrs. continuous running of the engine.
- As the concept of using biomass for bigger electricity generation projects is quite new for Nepal and till now don’t have existing running example as of hydro, further in depth study also needed, however theoretically it is very much possible.

5.3.2 Approach for Cost Estimation

- As the technology is new and existing running examples are not running in Nepal, only available service provider cost of project installation is considered. As per German experience the cost of electricity generation varies from 2000US$ to 4500US$ per kw power installation , hence here 3000US$ per kw is considered
- The waste collection and transportation is not considered as it is any how collect and transport is to be done to clean the city
- The opportunity cost of environmental protection not considered

5.4 WIND

5.4.1 Assumptions and Limitations

- Using the available wind speed data at 10m and 20m, calculations were done to calculate the wind speeds at 25m for different sites. Such calculations are theoretical and may not be 100% correct while implementing.
- The overall efficiency of the wind power generation unit is taken as 0.35. The overall system here means the combined efficiency of wind turbine and electrical generator. This value is subject to change depending upon the wind conditions and specifications of machines used in the system.
- The plant capacity factor is taken as 0.4 to calculate the total energy units generated in a year. Once again this value may differ depending upon the different load conditions.
- Due to difficulties in transportation and uneven topography, the radius of wind-blade is taken as 7m and not higher values.
- The nearest proposed substation is about 36 and 45 km from the two sites at Mustang and similar is the case of Okhaldhunga. Since this distance is quite large, the losses will also be high while transmitting the power.

5.4.2 Approach for cost estimation

- The per unit cost of electricity generated from wind is quite expensive than form the other sources as hydro and solar. The per kW construction cost of wind power in Nepal is about NPR 1,98,250. This cost also includes the cost of battery.
- The battery once installed should be replaced after 12 years. The cost of replacement is about 5000000 rupees.

5.5 COST OF GRID EXTENSION WITH AND WITHOUT DG

5.5.1 Assumption and Limitations:

- The total population within a ward is supposed to be concentrated at the geometrical centroid of that ward.
- The per capita load demand within VM/TM is supposed to be constant.
- Substations are proposed in those municipalities having no substation within it and in case of already existing substation, we recommend upgrading it.
- The distinction between electrified and un-electrified VM/TM is based on the data provided by CBS with the heading of “Source of Lighting”.
- If more than, 50% of the household has used electricity for lighting then it is categorized as electrified area and if not un-electrified area.
- The per capita electricity consumption of un-electrified area is taken as 180kWh/year whereas 300kWh/year for electrified area. It is based upon the data provided by NEA load forecasting report 2015.

- The population data has been collected form CBS, Census 2011.
- The geo-demographic center has been calculated using weighted centroid formula. The weight is based upon the population of each village within VM/TM.
- Substations are proposed at the geo-demographic centers calculated in step 2 with the tolerance of 1 km.
- The optimal grid extension is based upon modified Kruskals Algorithm, which is a minimum spanning tree algorithm. It joins those two points, which have minimum distance between them.
- For load flow analysis, each 132 kV substation were considered an infinite bus. Only domestic loads at 0.8 pf were considered for load flow while the industrial loads were neglected.
- The conventional Newton Raphson Method used for distribution system load flow might not give accurate result due to higher R/X ratio but in our case, Adaptive Newton Raphson method has been used whose result is satisfactory.

5.5.2 Cost Estimation

The following approach have been made for the estimation of cost.

- For the estimation of 132/33KV Substation, 33/11 KV Substation and 11 KV Switching Station NEA grid code standard has been followed and the estimated costs are based on present practice in NEA,
- 132KV, 33KV, 11KV Transmission line is proposed for power transmission and unit cost of above line is prepared .
- Cost apply to lines designed for maximum condition temperature +75

The primary objective of this study is to identify the optimum extension path of the Transmission and Distribution network to increase access to energy as well as integrate the proposed the proposed DG plants that may be feasible now or in the immediate future to initiate a sustainable power demand. Detailed study of the existing, under construction and proposed substations all over the Nepal has been made.

5.5.3 Analysis Approach:

5.5.3.1 EXISTING SUBSTATIONS

The first step of transmission line extension was to determine the total number and location of substation within Nepal Electricity Authority. The data was collected from NEA DCSD published magazine, NEA annual report, transmission line master-plan of NEA, Transmission Company of Nepal and through phone calls to NEA DCS all over the Nepal. The locations of substations were plotted on Google map with some margin of error due to unavailability of detailed data. They are placed within the same VDC as per their name on drawing titled "33 kV Transmission Line and Substations" provided by NEA.

5.5.3.2 EXISTING TRANSMISSION LINE

The second step was to determine the transmission line of Nepal within NEA. The data were collected form the map provided by Millennium Challenge Corporation and the drawing from NEA. If the detailed route of line was unavailable, two substations were connected by a straight line of realistic length and plotted in google map.

5.5.3.3 LOAD CALCULATION

The basis for load calculation was the CBS data of pre-existing VDCs and municipalities. Population of each ward was taken into consideration with some interpolations in case of missing data. The ward wise data was then transferred into Municipality level using the guide provided by Government of Nepal.

CBS 2011 presented a section titled "Source of Lighting" for each VDC so we divided each VDC into two category namely electrified and un-electrified. In every VDC if less than 50% are using electricity as source of lighting then, the VDC is considered to be un-electrified else electrified.

From NEA annual load forecast report, the load forecasted for year 18/19-22/23 is 410 kWh per consumer or household. On average per head, consumption comes out to be 84.01kWh with number of member per household taken as 4.88 according CBS census report 2011.The per capita electricity consumption is about 140 kWh as per World Bank in 2014. Our target is to achieve 300kWh per head consumption but this consumption depends upon whether the area is electrified or not .Un-electrified area cannot achieve this level of consumption so we multiply the per head consumption forecasted by NEA by the ratio of 300/140 which comes out to be 180.Therefore.the load demand per person was taken 300 KWh per year per person in electrified region and 180 KWh per year per person in un-electrified region. The network is planned to be constructed by 2023 (taking annual domestic load consumption to be 300 kWh in electrified areas and 180 kWh in un-electrified areas) and the transmission lines are designed for 2028 considering load increases by 15% annually on both electrified and un-electrified areas which would be in Tier 3 level of electricity access according to the Multi-Tier Framework.

Then village or town municipality was divided into four categories as follows:

- Unelectrified (U) = 0 – 24.99%
- Partially Electrified (PE) = 25 – 59.99%
- Partially Unelectrified (PU) = 60 – 79.99 %
- Electrified (E) = 80 – 100 %

5.5.3.4 Substation Location

The population of every municipality in ward basis was taken from CBS and processed to find out geo-demographic center (GDC) of each municipality. The GDC is calculated using the formula:

$$X_{out} = \frac{\sum_{i=1}^{N} P_i X_i}{\sum_{i=1}^{N} P_i} \qquad Y_{out} = \frac{\sum_{i=1}^{N} P_i Y_i}{\sum_{i=1}^{N} P_i}$$

Where, N is the number, P is the population weightage, and X and Y are the latitude and longitude of the wards of a Municipality. X_{out} and Y_{out} is the calculated latitude and longitude of the geo-demographic center of the Municipality. For calculation of GDC, population was assumed concentrated on geographic center of ward and the electrical load was then assumed concentrated at the same point. Substations were placed on the Geo Demographic Center if applicable or at the shifted GDC point to nearest settlement area. 33/11 kV substations were placed at those town municipalities having no substations in it and 11kV switching station were proposed at the village municipalities. If the existing substations were outside the radius of 5 km form the GDC, new substations were proposed at the GDC of that municipality.

5.5.3.5 Proposed Route Selection

At first, we created two pools of existing and proposed substations. Existing pool contained the substations of NEA that already exist or are proposed by NEA whereas the proposed pool contains the substations that we propose. For each proposed substation at proposed pool, nearest existing substation was selected based on minimum objective function which is a function of losses and voltage constraint and that proposed substation was added to existing pool. The process was repeated until all substations at proposed pool were transferred to existing pool. After all proposed to be connected from an existing was selected, the municipalities were identified and Kruskal’s algorithm was modified to first connect the municipalities with each other and then connect remaining gaupalika to the so formed network.

The voltage level of lines was based upon the load of the municipality and the distance between two substations. Four different lines of 11kV single circuit, 33 kV single circuit, 33kV double circuit and 132 kV single circuit were considered. In some cases, simply upgrading the lines to 33kV double circuit was not sufficient and for those cases, 132kV lines has been proposed from nearest 132 kV substation or if available as loop in loop out from existing 132kV line. The extension planning has been done in accordance of NEA Master Plan so that both transmission and distribution level works can be carried out side by side. 6/8 MVA transformers has been proposed in proposed substations wherever possible and 3 MVA has been proposed in hilly and mountainous region where load is low and there could be difficulty for transporting bigger size transformer.

The snowing regions has been observed briefly from ICIMOD data and as for now no underground transmission line has been proposed but the preliminary study shows, even if required, the underground transmission lines will not be for much longer lengths.

5.5.3.6 Load Flow Analysis

For load flow analysis, each 132 kV substation were considered an infinite bus. Only domestic loads at 0.8 pf were considered for load flow while the industrial loads were neglected. The conventional Newton Raphson Method used for distribution system load flow might not give accurate result due to higher R/X ratio but in our case, Adaptive Newton Raphson method has been used whose result is satisfactory.

After the selection procedure was complete, the infinite grid was then shifted to 220kV substation proposed by NEA or to the hubs proposed by substation where the to be constructed hydropower's power is to be evacuated. An eye was kept on the power obtained from those substations so that it won't cross the limit of power incoming to those substations. Now, regional load flow was done as the complete country's load flow did not converge in numerous attempt. At first, province wise load flow was performed, but later six different zones for power were identified and load flow was performed in six different regions irrespective of provincial division but corresponding to the power supplied from particular 132kV or 220kV substation.

In case of high population density area, current carrying capacity of transmission lines was kept in mind. The obtained lines were revised after this particular load flow was done. If an existing 33kV line is present in the route that has been proposed, loop in loop out from that particular route has been considered.

5.6 FINANCIAL MODELING

5.6.1 Approach

Best project for each municipality is chosen on the basis of least LCOE with assumption that the NEA tariff and LBOE for all technologies are similar. In case of biomass, although the LCOE is high, the LBOE and ROE are also the highest among the considered due to additional income from fertilizer, a by-product with high financial value in the agricultural market of Nepal. Therefore, wherever Biomass are identified, they are selected as the best available technologies. Nonetheless, the uncertainty in waste management practices and a scarcity of biomass-to-electricity pilot projects, hydro or solar PV projects may have to be reconsidered as these markets may be financially less attractive but they are well-established.

5.6.2 Assumptions

A discounted cash flow Financial Model was built in Excel (See Annex K)..The analysis was performed from the perspective of the private sector with the following assumptions:

- Financial Discount Rate was assumed to be 10%. This was calculated by averaging the Weighted Average Lending Rate (Commercial Banks) over a period of 4 years (16 data points) as published by Nepal Rastriya Bank (Quarterly Economic Bulletin July 2017). The calculations are shown in Table 3.
- Project is considered to be developed under the private sector model with 30% Equity and 70% Bank Loan at 10% Interest Rate with 12-year Loan repayment period.
- Capital Cost per kW (NPR/kW), O&M Cost per Year (%), O&M Escalation per year (%), Capacity Utilization Factor or Plant Load Factor (%) at the point of Grid Interconnection, Annual Energy Degradation (%), First Year PPA Rate (NPR/kWh), PPA Escalation per year for 8 years (%), Income Tax on Profits (%)were taken as inputs. The Capital Cost per kW was calculated with applicable VAT and Customs duty. The assumed values are in Annex K.
- The outputs were Net Present Value (NPV), Return on Equity (ROE), Pay-back Period, Levelized Cost of Electricity (LCOE) and Levelized Benefit of Electricity (LBOE).
- Government Viability Gap Funding (VGF) (NPR/kW) was calculated based on the assumption that the VGF will help the ROE to be between 15.00 – 15.50 %
- Sensitivity Analysis is performed for Solar PV plants for Scenarios of with and without Battery Storage at different costs, and for Hydropower Plants at reduction of discharge.

Table 3 : Calculation of Financial Discount Rate

S.N.	Date	Weighted Average Lending Rate (Commercial Banks) (%)
1	Oct-13	11.78
2	Jan-14	11.53
3	Apr-14	10.92

4	Jul-14	10.55
5	Oct-14	10.14
6	Jan-15	9.82
7	Apr-15	9.64
8	Jul-15	9.62
9	Oct-15	9.46
10	Jan-16	9.29
11	Apr-16	9.06
12	Jul-16	8.86
13	Oct-16	8.62
14	Jan-17	9.31
15	Apr-17	10.77
16	Jul-17	11.33
Average (4-year)		**10.0**

5.6.3 Limitations

Although all assumptions have been made carefully, some limitations exist:

- Further sensitivity analysis may be necessary in case of Wind and Biomass technologies
- There may be some uncertainty in results (financial indicators and site selection based on these indicators) which will require further detailed field investigations.

5.7 ECONOMIC MODELING

5.7.1 Approach

A discounted Cost-Benefit Economic Model is used to perform economic analysis from the perspective of the government with appropriate Social Discount Rate, Capital Cost per kW (NPR/kW) for DG projects, Capital Cost per kW (NPR/kW) for Central, and O&M Cost per Year (%). As the analysis was performed from the perspective of the Government, All Cost parameters were calculated excluding the applicable VAT and Customs duty charged by the government. The estimated values are presented in Annex D. Economic analysis was performed Province-wise for two scenarios:

5.7.1.1 A: Grid Extension to all Municipalities WITH the DG sources

- The Capital Cost of Grid Extension are calculated which includes the costs of T&D lines, hubs and substations.
- The Costs of DG projects selected through Financial Analysis are included in the Capital Cost
- The energy consumed in the system is estimated for Electrified, Partially Unelectrified, Partially Electrified, and Unelectrified Municipalities.

- The difference of energy between the total load demand and energy supplied from DG plants has been assumed to be supplied from Central Hydropower Plants with 60% PLF. The O&M (2%) and Capital costs of these plants (NPR 170,000/kW) are included in the Costs.
- The System losses of bottom-up DG architecture are estimated at 9%(6% Distribution losses, 3% Outage, 0% T&D losses because they have already been accounted for during energy calculations of DG project i.e. CUF and PLF at grid interconnection point)
- Benefits are calculated on the basis of Fuel Replacement in Unelectrified areas and Willingness to Pay in Electrified areas. These assumptions are summarized in Annex L.

5.7.1.2 B: Grid Extension to all Municipalities WITHOUT the DG sources

- The Grid extension costs are calculated including the costs of T&D lines, hubs and substations. Electrical load flow analysis indicates that the Cost of Grid Extension with DG is lower than that of without DG. Comparatively, lower capacity lines and substations are necessary to deliver electricity access when DG sources are available due to improvement in Grid Voltage and Performance.
- The Capital Cost of Grid extension are calculated which includes the costs of T&D lines, hubs and substations
- The total load demand has been assumed to be supplied from Central Hydropower Plants with 60% PLF. The O&M (2%) and Capital costs of these plants (NPR 170,000/kW) are included in the Costs.
- The System and Reliability losses of traditional top-down energy architecture are estimated at 18% (6% T&D losses, 6% Distribution losses, 6% Outage).
- The energy consumed in the system is estimated for Electrified, Partially Un-electrified, Partially Electrified, and Un-electrified Municipalities. These assumptions are summarized in Annex L.

5.7.2 Assumptions

A discounted Cost-Benefit Economic Model was built in Excel (See Annex L). Economic analysis was performed from the perspective of the government with the following assumptions:

- Economic or Social Discount Rate (SDR) was assumed to be 2%. This rate has been calculated by averaging the interest on Treasury-bills (364 days) over a period of 4 years (15 data points) as published by Nepal Rastriya Bank (Quarterly Economic Bulletin July 2017) and adding 0.7% for market distortion in the Base Case. This calculation is shown in
- Table **4**.
- Further, Sensitivity Analysis is performed at 5% and 8% SDR.
- Capital Cost per kW (NPR/kW) for DG projects were calculated using a modified Financial Model
- Capital Cost per kW (NPR/kW) for Central Plants were estimated from market reserach
- As the analysis was performed from the perspective of the Government, so all Cost parameters were calculated excluding the applicable VAT and Customs duty charged by the government. The estimated values are presented in Annex L.

Table 4 : Calculation of Social Discount Rate (SDR)

S.N.	Date	Interest on T-bills (%)
1	Oct-13	0.79
2	Jan-14	1.06
3	Apr-14	0.68
4	Jul-14	0.72
5	Oct-14	0.93
6	Jan-15	0.37
7	Apr-15	1.16
8	Jul-15	0.76
9	Oct-15	1.97
10	Jan-16	0.94
11	Apr-16	1.29
12	Jul-16	0.72
13	Oct-16	2.74
14	Jan-17	2.70
15	Apr-17	2.31
16	Jul-17	-
Average (4-year)		1.3%
Market Distortion (Base Case)		0.7%
SDR (Base Case)		**2.0%**

5.7.3 Limitations

Limitations of economic analysis are as follows:

- The economic model captured the following elements of Grid Extension WITH DG development: (i) reduction of Capital and Operational expenditure of Transmission and Distribution networks (Grid Extension) due to active and reactive power support (ii) reduction of power transmission losses by servicing local loads, and (iii) economic benefits from fuel replacement and willingness to pay according to the electrification status of the Municipality. However, due to limitations of time and scarcity of published local research, additional economic benefits of Grid Extension WITH DG such as (i) fewer social and environmental consequences over large central plants, and (ii) ripple economic effect through forward and backward economic linkages that can kick-start the local economy could not be captured in the model. Therefore, the estimated benefit values for Grid Extension WITH DG are conservative and would be higher in reality.
- The true benefits of electricity are multidimensional and extend into health, environment, social, and other sectors; therefore, the estimated benefit values both cases are conservative; the true economic benefit for would be higher.

- Due to scarcity of time and field investigations, the economic model only considers fuel replacement (in partially electrified, partially unelectrified, and unelectrified areas) and willingness to pay (in electrified areas) available in literature. Percentages of these two parameters in electrified and un-electrified areas are estimated and may need to be studied in detail to improve the economic model.
- Further econometric studies may be required to accurately estimate the benefits of electricity for both Cases

6 FINDINGS & DISCUSSION

6.1 HYDROPOWER

Detailed study of the existing rivers all over Nepal has been made. The study has concluded the following outputs. The study shows that there is potential of hydropower ranging from 500 kW to 1000 kW in 277 Local Bodies with total identified sites (maximum 3 no. of sites taken in this study) are 456. Total power potential is found to be 383.56 MW. In Province No: 02 no hydropower sites in the given range have been found. The province wise summary is presented in the table below.

Table 5 : Province wise Summary of Identified Hydropower Sites

S.N.	Province	No. of Local Bodies	No. of Sites Identified	Power (MW)
1	Province 1	56	84	66.11
2	Province 2	-	-	-
3	Province 3	53	81	64.44
4	Province 4	29	54	45.14
5	Province 5	23	38	26.995
6	Province 6	60	102	94.759
7	Province 7	56	97	86.119
	Total	**277**	**456**	**383.56**

In total 456 hydro sites have been found considering at most 3 hydropower projects in each local body. Among the 277 local bodies with hydropower sites identified, it is found that there is already hydropower projects under operation in 29 Local bodies. So, only 248 local bodies have been considered as the potential Local Bodies to generate energy from hydropower projects.

Table 6 : Summary of Hydropower Projects selecting one hydro from each local body

S. N.	Province No:	No. of Local Bodies	Power (MW)	Remarks
1	1	50	40.76	12,892.86
2	2	-	-	-
3	3	39	28.95	10,377
4	4	23	20.07	5,493
5	5	22	15.78	6,854

6	6	59	54.20	22,538
7	7	55	48.78	15,872
	Total	**248.00**	**208.54**	**74,026.20**

Province 01 (Identified Hydropower Sites)

The study shows that there is potential of hydropower ranging from 500 kW to 1000 kW in 56 Local Bodies with total identified sites (maximum 3 no. of sites taken in this study) are 84. Cumulative power potential is found to be 66.11 MW.

Table 7 : Summary of Province 01 (Identified Hydropower Sites)

S.N.	District	No. of Local Bodies	No. of Sites Identified	Power (MW)
1	Bhojpur	8	10	8.13
2	Dhankuta	5	7	4.98
3	Ilam	6	6	3.68
4	Khotang	9	20	16.29
5	Okhaldhunga	4	6	5.56
6	Panchthar	4	8	6.29
7	Sankhuwasabha	6	6	5.00
8	Solukhumbu	3	5	3.74
9	Taplejung	3	3	2.32
10	Terhathum	5	7	5.63
11	Udayapur	3	6	4.49
	Total	**56**	**84**	**66.11**

Province 03 (Identified Hydropower Sites)

The study shows that there is potential of hydropower ranging from 500 kW to 1000 kW in 53 Local Bodies with total identified sites (maximum 3 no. of sites taken in this study) are 81. Cumulative power potential is found to be 64.44 MW.

Table 8 : Summary of Province 03 (Identified Hydropower Sites)

S.N.	District	No. of Local Bodies	No. of Sites Identified	Power (MW)
1	Dhading	8	12	9.38
2	Kavrepalanchowk	7	9	7.41
3	Lalitpur	2	2	1.59
4	Makwanpur	2	4	3.16
5	Rasuwa	5	10	8.40
6	Sindhuli	2	3	2.00

7	Sindhupalchowk	9	13	9.78
8	Dolakha	5	9	8.04
9	Nuwakot	6	10	7.85
10	Ramechhap	7	9	6.83
	Total	**53**	**81**	**64.44**

Province 04 (Identified Hydropower Sites)

The study shows that there is potential of hydropower ranging from 500 kW to 1000 kW in 29 Local Bodies with total identified sites (maximum 3 no. of sites taken in this study) aare 54. Cumulative power potential is found to be 45.14 MW.

Table 9 : Summary of Province 04 (Identified Hydropower Sites)

S.N.	District	No. of Local Bodies	No. of Sites Identified	Power (MW)
1	Baglung	7	16	13.30
2	Gorkha	2	5	4.36
3	Kaski	1	1	1.00
4	Lamjung	5	6	4.18
5	Manang	3	5	4.85
6	Mustang	4	10	9.41
7	Myagdi	4	7	5.25
8	Parbat	1	1	0.52
9	Syangja	2	3	2.29
	Total	**29**	**54**	**45.14**

Province 05 (Identified Hydropower Sites)

The study shows that there is potential of hydropower ranging from 500 kW to 1000 kW in 23 Local Bodies with total identified sites (maximum 3 no. of sites taken in this study) are 38. Cumulative power potential is found to be 27 MW.

Table 10 : Summary of Province 05 (Identified Hydropower Sites)

S.N.	District	No. of Local Bodies	No. of Sites Identified	Power (MW)
1	Gulmi	2	3	1.65
2	Palpa	5	7	4.63
3	Pyuthan	4	6	4.41
4	Rolpa	9	15	10.83
5	Rukum	3	7	5.48

	Total	**23**	**38**	**27.00**

Province 06 (Identified Hydropower Sites)

The study shows that there is potential of hydropower ranging from 500 kW to 1000 kW in 60 Local Bodies with total identified sites (maximum 3 no. of sites taken in this study) are 102. Cumulative power potential is found to be 94.76 MW.

Table 11 : Summary of Province 06 (Identified Hydropower Sites)

S.N.	District	No. of Local Bodies	No. of Sites Identified	Power (MW)
1	Jajarkot	8	15	14.49
2	Dailekh	5	6	3.73
3	Salyan	4	4	2.96
4	Surkhet	5	7	6.09
5	Mugu	4	9	8.29
6	Rukum	5	8	7.63
7	Humla	6	9	8.79
8	Dolpa	7	12	11.70
9	Kalikot	9	19	18.08
10	Jumla	7	13	13.00
	Total	**60**	**102**	**94.76**

Province 07 (Identified Hydropower Sites)

The study shows that there is potential of hydropower ranging from 500 kW to 1000 kW in 56 Local Bodies with total identified sites (maximum 3 no. of sites taken in this study) are 97. Cumulative power potential is found to be 86.12 MW.

Table 12 : Summary of Province 07 (Identified Hydropower Sites)

S.N.	District	No. of Local Bodies	No. of Sites Identified	Power (MW)
1	Achham	6	8	6.27
2	Baitadi	10	20	16.17
3	Bajhang	9	21	20.63
4	Bajura	9	17	16.63
5	Dadeldhura	7	9	6.43
6	Darchula	7	11	10.82
7	Doti	6	9	7.41
8	Kailali	2	2	1.75
	Total	**56**	**97**	**86.12**

6.1.1.1 Analysis Approach:

Hydrological Analysis is made by using DHM/WECS method, Modified Hydest Method and the Basin wise approach based on DHM Mean Monthly data for up to 2006 AD. DHM/WECS Method has shown the discharge relatively in lower side and Modified Hydest Method has resulted into higher discharge for the same intake point. The hydrological analysis shows that the discharge is relatively higher in the eastern region and goes on decreasing in western region.

Site Identification

In this study, design discharge is estimated for 65% probability of flow exceedance. Some of the major findings by this approach are as following.

1. Almost no hydropower sites have been found in Terai Districts. Exceptionally sites have been found in Kailali.
2. In some hilly districts like Tanahun and Arghakhanchi no hydropower sites have been found at 65% of flow exceedence.
3. In Parbat and Kaski, Only one hydropower sites have been found. Minimum numbers of hydropower sites have been found in districts like Salyan, Surkhet and some other districts.
4. In many Local bodies (Rual Municipality and Municipality) no hydropower sites have been found.
5. In hilly districts like Manang, Mustang, Dolpa, Mugu, Humla, Jumla and Kalikot very few numbers of sites have been found in small streams. Most of the sites identified in these districts are from the main rivers in upstream side.
6. Additional sites may be found in some hilly districts in 45% probability of flow exceedence.
7. Mini-grids that interlink existing micro or mini-hydropower plants may also be feasible depending on local conditions. They should be studied on a case by case basis as recommended by this World Bank study (https://goo.gl/NMVXxh).

Site Verification

The present study is made based on the available data, information and analysis tools for finding the discharge. Topographical maps and digital maps are used for finding the measurement. So, flow verification of the identified sites have been proposed and need to carry out different stages of consulting study before the implementation of the projects.

Similarly the verification of the proposed sites in reference to the proposed general layout needs to be carried out.

Availability of the Substation

In the present study, the distance from the identified projects powerhouse to substation is calculated for existing or the proposed substation whichever in nearer. So, in most of the identified sites, the cost of the project may even increase if the distance up to existing substation is taken into consideration.

Availability of Land

The present study has not included the cost of land that needs to be acquired during the construction of the project. In remote areas, this cost may very small however in some accessible areas even the project may have to pay huge amount for land acquisition.

Water Right Issues

It has not been possible to find the water right issue in the present study. In some streams like Sharada river in Salyan and some other rivers where there is significant land to be irrigated might use huge amount of water for irrigation. So, such impacts needs to be confirmed in next phase of Feasibility study.

Geological Issues

The present study also needs to be verified geologically and some sites might be rejected with geological requirements.

Time Schedule for Project Implementation

The identified project shall be implemented to meet the energy crisis of Nepal. The implementation of project can be done in the five years planning model as listed below time schedule. First implementation ranking should be given to the area where there is no electricity till now.

6.1.2 Financial Analysis of Hydropower at different Costs

Financial Analysis is performed for Hydropower to get a better understanding of financial indicators and VGF required for a range of Capital Costs with the same revenue of NPR 6/kWh NEA PPA Rate with 8 simple escalations of 3% each. The range of costs have been selected to represent the minimum and maximum cost of the Hydropower Projects selected through this study. The results are presented in Table 13.

Table 13 : Financial Analysis of Hydropower (1000 kW) at different Costs

COST / OUTPUT	Cost I	Cost II	Cost III	Cost IV	Cost V	Cost VI	Cost VII
	Capital Cost* [NPR/ kW] = 162,528	Capital Cost [NPR/ kW] = 200,000	Capital Cost [NPR/ kW] = 235,000	Capital Cost [NPR/ kW] = 300,000	Capital Cost [NPR/ kW] = 400,000	Capital Cost [NPR/ kW] = 500,000	Capital Cost [NPR/ kW] = 579,475
LCOE [NPR/kWh]	3.95	4.86	5.71	7.29	9.72	12.15	14.09
LBOE [NPR/kWh]	7	7	7	7	7	7	7
ROE [%]	30.85%	20.93%	15.07%	8.33%	2.30%	-1.65%	-4.11%
NPV [NPR-Million]	136.78	93.29	52.66	-22.77	-138.84	-254.91	-347.15
Cost Benefit Ratio	3.81	2.55	1.75	0.75	-0.16	-0.70	-1.00
Pay Back Period [Years]	3.75	6.15	9.56	14.70	21.02	>25	>25
VGF required per kW [NPR/ kW]**	None	None	0	79,000	201,000	323,000	420,000
First Year PPA Rate* required [NPR/ kWh]**	4.16	5.12	6.00	7.67	10.22	12.77	14.81

NOTES:

* O&M Costs changes as well because Yearly O&M Costs is calculated as 3% of Capital Cost

** To achieve at least 15% ROE (criteria for financial viability)

*** With 8 simple escalations of 3% each to achieve 15% ROE in case of No VGF provided

As can be seen from the Table 13, for the case of 1 MW Hydropower Plant with 65% PLF, the range of Capital Cost per kW has significant effects on the financial attractiveness of the project. For Capital Costs from NPR 162,528 to 235,000 per kW (Costs I, II & III), the ROE is above 15% and no VGF is required at the current PPA Rate (NPR 6/ kWh). For projects with Capital Costs from NPR 235,000 to 300,000 per kW (Cost IV), the VGF required is less than NPR

80,000/kW. Beyond Capital Costs of NPR 317,000/kW (Cost V, VI, VII), the VGF required increases beyond 100,000/kW.

6.1.3 Sensitivity Analysis of Hydropower with Reduction in Discharge

Sensitivity Analysis is performed for Hydropower plants to get a better understanding of financial indicators and VGF required with 5% reduction in energy production (revenue) due to reduction in discharge for a range of Capital Costs with the same PPA Rate of NPR 6/kWh NEA PPA Rate with 8 simple escalations of 3% each. The results are presented Table 14.

Table 14 : Sensitivity Analysis of Hydropower (1000 kW) with Reduction in Discharge

COST / OUTPUT	Case I	Case II	Case III	Case IV	Case V	Case VI	Case VII
	PLF = 61.75%	PLF = 61.75%	PLF = 61.75%	PLF = 61.75%	PLF = 61.75%	PLF = 61.75%	PLF = 61.75%
	Capital Cost* [NPR/ kW] = 162,528	Capital Cost [NPR/ kW] = 200,000	Capital Cost [NPR/ kW] = 223,000	Capital Cost [NPR/ kW] = 300,000	Capital Cost [NPR/ kW] = 400,000	Capital Cost [NPR/ kW] = 500,000	Capital Cost [NPR/ kW] = 579,475
LCOE [NPR/kWh]	4.16	5.12	5.71	7.68	10.23	12.79	14.83
LBOE [NPR/kWh]	7	7	7	7	7	7	7
ROE [%]	28.11%	18.91%	15.07%	7.14%	1.36%	-2.51%	-4.96%
NPV [NPR-Million]	120.51	77.02	50.32	-39.04	-155.11	-271.18	-363.42
Cost Benefit Ratio	3.47	2.28	1.75	0.57	-0.29	-0.81	-1.09
Pay Back Period [Years]	4.21	7.04	9.52	15.62	22.51	>25	>25
VGF required per kW [NPR/ kW]**	None	None	0	94,000	216,000	338,000	435,000
First Year PPA Rate* required [NPR/ kWh]**	4.37	5.39	6.00	8.08	10.78	13.48	15.61

NOTES:

* O&M Costs changes as well because Yearly O&M Costs is calculated as 3% of Capital Cost

** To achieve at least 15% ROE (criteria for financial viability)

*** With 8 simple escalations of 3% each to achieve 15% ROE in case of No VGF provided

As can be seen from the Table 14, for the case of 1 MW Hydropower Plant with 5% reduction in electricity production due to reduction in discharge (61.75% PLF), has some minor effects on the financial attractiveness of the projects. Compared to the Base Case, the maximum Capital Cost limit of financial viability (i.e. ROE>15%) without any VGF decreases to NPR 223,000/kW. Now, for Capital Costs from NPR 162,528 to 223,000 per kW (Case I, II & III), the ROE is above 15% and no VGF is required at the current PPA Rate (NPR 6/ kWh). For projects with Capital Costs from NPR 223,000 to 300,000 per kW (Case IV), the VGF required is less than NPR 95,000/kW. Beyond Capital Costs of NPR 305,000/kW (Case V, VI, VII), the VGF required increases beyond 100,000/kW. Therefore, even with decrease in energy produced by 5%, hydropower projects with Capital Costs below NPR 223,000/kW are financially attractive without any VGF at the current NEA PPA rate of NPR 6/kWh. In case VGF is limited to NPR 100,000/kW, hydropower projects with Capital Cost not more than NPR 305,000/kW will be financially attractive. For projects beyond this cost, it could be better to wait until road access in respective Municipalities could be improved so that Capital Costs can be decreased to NPR 305,000/kW with maximum of NPR 100,000/kW viability gap funding.

6.2 SOLAR PV

6.2.1 Region wise Financial Analysis

Table 15 presents the results of financial analysis of 1000 kWac Solar PV projects with 500 kWh Battery Storage for the Base Case for each Region.

Table 15 : Summary of Financial Analysis of Solar PV Projects with Battery Storage

Region	Size (kWac)	Capital Cost per kW (NPR/ kWac)	CUF at Grid Interconnection Point (%)	LCOE before VGF (NPR/ kWh)	ROE before VGF (%)	VGF Amount (NPR/ kWac)	LCOE after VGF (NPR/ kWh)	LBOE (NPR/ kWh)
A	1000	164,661	17.40%	14.02	-3.22%	110,000	5.90	6.98

B	1000	165,311	17.00%	14.40	-3.62%	113,000	5.87	6.98
C	1000	164,661	18.40%	13.25	-2.41%	106,000	5.86	6.98
D	1000	165,311	19.50%	12.56	-1.60%	102,000	5.84	6.98
E	1000	166,351	20.60%	11.96	-0.85%	99,000	5.79	6.98
F	1000	169,211	20.60%	12.16	-1.11%	102,000	5.81	6.98

As can be seen from Table 15, the LCOE is NPR 11.96, 12.16, 12.56, 13.25, 14.02 and 14.40 per kWh for Region E, F, D, C, A and B respectively. Region E results in the lowest LCOE due to the highest CUF in spite of second highest Capital Cost (highest among Regions requiring road transportation). Region F with the highest CUF and highest Capital Cost (highest due to this Region requiring air transportation) results in second lowest LCOE among all Regions. The high CUF of Regions E and F compensates for the higher Capital Costs to result in most cost effective solutions in these regions. Region B has the highest LCOE due to the lowest CUF in spite of having the second lowest Capital Cost. Similarly, the second highest LCOE occurs for Region A due to second lowest CUF in spite of having the lowest Capital Cost due to the lowest transport cost. Therefore, the cost effectiveness of the Solar PV with Storage project is highly dependent on the CUF but not so much on the transport costs.

6.2.2 Sensitivity Analysis of Region A

6.2.2.1 *Scenario A: Solar PV With Battery*

Sensitivity Analysis is performed for Region A to get a better understanding of changes in financial indicators and VGF required with decrease in Capital Cost when compared with the Base Case for this Scenario with the same revenue of NPR 6/kWh NEA PPA Rate with 8 simple escalations of 3% each. The results are presented in Table 16.

Table 16 : Sensitivity Analysis of Scenario A (1 MWac Solar PV With 500 kWh Battery Backup)

CASE / OUTPUT	Base Case	Case I	Case II	Case III	Case IV	Case V
	Capital Cost* [NPR/ kW] = 164,661	Capital Cost [NPR/ kW] = 140,000	Capital Cost [NPR/ kW] = 120,000	Capital Cost [NPR/ kW] = 100,000	Capital Cost [NPR/ kW] = 80,000	Capital Cost [NPR/ kW] = 60,000
LCOE [NPR/kWh]	14.02	11.93	10.25	8.56	6.87	5.18
LBOE [NPR/kWh]	6.98	6.98	6.98	6.98	6.98	6.98
ROE [%]	-3.22%	-0.84%	1.60%	4.86%	9.67%	18.25%
NPV [NPR-Million]	-89.38	-63.67	-42.81	-21.95	-1.09	19.75
Cost Benefit Ratio	-0.81	-0.52	-0.19	0.27	0.95	2.10
Pay Back Period [Years]	>25 years	>25 years	22.07	17.81	13.96	6.88
VGF required per kW [NPR/ kW]**	110,000	83,000	61,000	38,000	16,000	None
First Year PPA Rate*required [NPR/ kWh]**	14.85	12.63	10.86	9.04	7.27	5.47

NOTES:

* O&M Costs decrease as well because Yearly O&M Costs is calculated as 1.5% of Capital Cost

** To achieve at least 15% ROE (criteria for financial viability)

*** With 8 simple escalations of 3% each to achieve 15% ROE in case of No VGF provided

As can be seen from the in Table 16, for the case of 1 MWac Solar PV Plant with 500 kWh Storage, the Capital Cost per kW has to decrease extremely from NPR 164,661/kW (base Case) to approx. NPR 60,000/ kW(Case V) for financially attractiveness without VGF, which is unrealistic in present market scenario. In case of mild and realistic decrease in the Capital Cost per kW to NPR 140,000 (Case I) and NPR 120,000 (Case II) in the near future, the VGF required decreases but is still high (Case I: NPR 83,000 and Case II: NPR 61,000). Further, in case no federal VGF is provided, the First Year NEA PPA Rate with 8 simple escalations of 3% required to achieve a ROE of 15% is still high at NPR 12.63/ kWh (Case I) and NPR 10.86/ kWh (Case II). Therefore, it is highly unlikely that small scale (~1 MWac) Solar PV plants with Storage (~500 kWh) will be financially attractive without any VGF in the near future even with mild decrease in costs.

6.2.2.2 Scenario B - Solar PV Without Battery

Financial analysis of Solar PV plant without Battery Backup is performed for Region A to better understand the changes costs in case no battery backup is considered. Further, Sensitivity Analysis is performed to get a better understanding of changes in financial indicators and VGF required with decrease in Capital Cost when compared with the Base Case for this Scenario (with the same revenue of NPR 6/kWh NEA PPA Rate with 8 simple escalations of 3% each). The results are presented in Table 17.

Table 17 : Sensitivity Analysis of Scenario B (1 MWac Solar PV Without Battery Backup)

CASE / OUTPUT	Base Case	Case I	Case II	Case III
	Capital Cost* [NPR/ kW] = 120,211	**Capital Cost [NPR/ kW] = 100,000**	**Capital Cost [NPR/ kW] = 80,000**	**Capital Cost [NPR/ kW] = 60,000**
LCOE [NPR/kWh]	10.15	8.44	6.75	5.06
LBOE [NPR/kWh]	6.98	6.98	6.98	6.98
ROE [%]	1.90%	5.23%	10.10%	18.70%
NPV [NPR-Million]	-41.59	-20.52	0.335	21.19
Cost Benefit Ratio	-0.15	0.32	1.01	2.18

Pay Back Period [Years]	21.53	17.26	13.44	6.88
VGF required per kW [NPR/ kW]**	60,000	36,000	15,000	None
First Year PPA Rate* required [NPR/ kWh]**	10.79	8.96	7.18	5.39

NOTES:

* O&M Costs decrease as well because Yearly O&M Costs is calculated as 1.5% of Capital Cost

** To achieve 15% ROE at the given PPA Rate

*** With 8 simple escalations of 3% each to achieve 15% ROE in case of No VGF provided

As can be seen from Table 16 and Table 17, the LCOE decreases substantially from NPR 14.02/ kWh (Scenario A – Base Case with Battery) to NPR 10.15/ kWh (Scenario B – Base Case without Battery) when battery backup is removed (i.e. Capital Cost per kW decrease from NPR 164,661 to NPR 120,211). This reduction in LCOE implies that more Solar PV plants without Storage would be selected at the Municipality Level due to the decrease in LCOE; nonetheless, it would be crude to compare 1 MWac Solar PV Plant Without Battery Storage that can be operated only during the day and has a low CUF of 17.4% to 1 MWac Hydropower Plant that can be operated at any time of the day with a higher PLF of 65%. Therefore, while selecting the best DG project for each Municipality, all comparison with 1 MWac Hydropower Plant is only performed against 1 MW ac Solar PV with 500 kWh of Battery Storage, such that they can provide similar level of electricity service.

Nonetheless, as can be seen from the in Table 16 for the case of 1 MWac Solar PV Plant Without any Battery Storage, the Capital Cost per kW has to decrease extremely from NPR 120,211/kW (Base Case) to approx. NPR 60,000/ kWp (Case III) for financially attractiveness of project without VGF, which is unrealistic in present market scenario. In case of mild and realistic decrease in the Capital Cost per kW to NPR 100,000 (Case I) and NPR 80,000 (Case II) in the near future, the VGF required decreases substantially (Case I: NPR 36,000 and Case II: NPR 15,000). Further, in case no federal VGF is provided, the First Year NEA PPA Rate with 8 simple escalations of 3% required to achieve a ROE of 15% is NPR 8.96/ kWh (Case I) and NPR 7.18/ kWh (Case II) respectively. Nonetheless, for the case of Nepal, the decrease in Capital Cost per kW from current estimated cost of NPR 120,211/ kW (Base Case without Battery) to NPR 80,000/ kW (Case II without Battery) may require substantial policy interventions such as exemptions on tax, custom duty and excise duty, and simultaneous decrease in cost of equipment of solar panels, inverters and other accessories. Therefore, to induce financial attractiveness without providing any federal VGF for small scale (~1 MWac)Solar PV plants without battery storage, GoN could revise its policy regarding PPA rate for these plants, and tax and custom duty exemptions for associated equipment.

6.2.3 Selected Solar PV Sites

Table 18 : Summary of Identified Solar PV Sites

Provinces	Number of Local Bodies with Solar Sites	Installed Capacity of Selected Solar Sites	Total Cost of Solar Sites (Million NPR)
1	71	71 MWp	11,712
2	127	127 MWp	20,911
3	70	70 MWp	11,559
4	58	58 MWp	9,585
5	85	85 MWp	14,020
6	33	33 MWp	5,512
7	37	37 MWp	6,126
Total:	**481**	**481 MWp**	**79,428**

A total of 481 MWp of Solar PV Projects with 500 kWh Battery Storage were identified in 481 local bodies. Solar sites were selected where hydropower sites were not existent or too costly on the basis of LCOE. Province 2 has the highest number of selected solar sites as they lack any hydropower resources within the scope of this study. The lowest number of sites were selected in Province 5. The overall capital cost of these selected Solar projects with storage is approximately NPR 79 billion.

6.3 BIOMASS

Two types of projects are consider in this study one with biomass with agro waste and another with municipality waste.

6.3.1.1 Biomass project with Agro waste:

Biomass is one of the major source of energy in Nepal, 85% energy to Nepalese is obtained from biomass. Most of the biomass is used by firing, the heat obtained from fire is used to fulfil the energy demand and it is in most of the case traditional practice, which conserve more biomass and not environmental friendly as emitting lots of smokes .The improvement on extracting biomass into modern form of energy shall have greater scope. Two option can be used one improving the traditional stove and another Electrification through biomass. The use of biomass feed stocks in energy generation essentially promotes the development of healthy and sustainable local economies.

Till date agro waste are not being burden to Nepalese society as most of the agro business are for subsistence livelihood and the waste is conserved within the business premises. However when the size of business will increase into commercialization, agro waste may become the challenge and needs to be managed properly.

The management of agro waste should be with recovering soil nutrient itself so that degradation of soil nutrient shall be recovered. The best way of managing it is biogas technology, which will produce methane as well as compost.

Methane shall be used to produce electricity and compost as soil nutrient improver. Depending on the type of waste anaerobic digestion of wet or dry shall be used as energy extracting method. Paddy, maize, millet, wheat are the major cereal crop and mustard, sugarcane, Jute soya bean etc. are major cash crop of Nepal. The quantity of residue of cereal crop production is presented in Table below.

Table 19 : Crops, their residue type and their RPR

Crop type	Residue type	Residue Production Ratio (RPR)
Paddy	Total residue	1.68
	Straw	1.413
	Husk	0.267
Maize	Total residue	2.473
	Stalk	2
	Cob	0.273
	Husk	0.2

Millet	Stalk	1.08
Wheat	Straw	1.75

Source: (Bhattacharya, et el 1993)

As per the bio energy consult study the electricity generation potential of paddy residue is presented in the box. Let's assume that only rice husk is used for electricity production. Hence one ton of rice husk is equivalent to 410 to 570 kWh. (https://www.bioenergyconsult.com/tag/energy-potential-of-rice-husk) Taking the lower side of 410kwh/ t. Rice husk from one ton of rice can produce 90kwh energy.

Based on above assumption, fourteen district are identified with the enough paddy production for project above 500kw. Further municipality wise analysis need to be performed.

Table 20 : Cost analysis of Biomass project with agro waste

SN	District	State	Paddy production (MT)	Straw (kg)	Rice husk (kg)	Potential power generation , with set assumption	Proposed project size KW	Cost of project (Million NPR)
1	Jhapa	1	320790	93029100	70573800	1651	1000	300
2	Morang	1	259289	75193810	57043580	1334	1000	300
3	Sunsari	1	160650	46588500	35343000	827	800	240
4	Dhanusha	2	125054	36265660	27511880	643	600	180
5	Bara	2	231880	67245200	51013600	1193	1000	300
6	Parsa	2	164360	47664400	36159200	846	800	240
7	Nawalparas	5	179110	5194190	3940420	922	900	270

	i			0	0			
8	Rupandehi	5	319695	92711550	70332900	1645	1000	300
9	Kapilbastu	5	205118	59484220	45125960	1056	1000	300
10	Dang	5	157384	45641360	34624480	810	800	240
11	Banke	5	109226	31675540	24029720	562	500	150
12	Bardiya	7	159575	46276750	35106500	821	800	240
13	Kailali	7	185980	53934200	40915600	957	900	270
14	Kanchanpur	7	138630	40202700	30498600	713	700	210

6.3.1.2 Biomass project with Municipal waste:

Municipal waste management is emerging challengeof the municipality. Energy extracting plant The basic parameter used to waste quantification and characterisation is presented in the table below and calculation is based in these key data with the source of Baseline and Feasibility Assessment of the Waste to Energy Projects for Potential Financing under Market/Non-Market Mechanisms.

Table 21 : Biomass project with municipal waste

SN	Parameters	Unit	Value	Reference
1	Population Growth	%	1.35%	CBS, 2011
2	Annual Urban population growth rate	%	6.44%	CBS,2001

3	Average Household Waste Generation	kg/day / capita	0.17	ADB, 2012
4	Average Municipal waste generation	kg/day /capita	0.317	ADB, 2012
5	Average waste increment rate per annual (municipal)	%	3%	Jha et al ,2010
6	% of biodegradable waste in total waste	%	61%	Jha et al ,2010
7	Biogas production per 1Ton of biodegradable waste	M3	100	http://www.tankonyvtar.hu/en/tartalom/tamop425/0032_kornyezet technologia_en/ch01s02.html
8	Energy Value of 1 cum biogas	kWhel	1.5-3.0	Bioenergy in Germany: Facts and Figures

The municipality waste is quite difficult to define as it depends area to area and place to palce and method of collection. In poor area there will be less organic material whereas in a rich district, more organic with oil content shall be obtained.

Gaupalika waste is not feasible for electric generation plant for grid, as population density is less and no waste collection mechanism exist. City density having more than 500 are only considered. The waste will be kitchen waste and bio-waste But it is assume that the sorting and removal of inert material has taken place so that relatively free from inert material bio-waste may be used.

As per the key data of above: approximately it can say that 1 m3 biogas could be able to generate1.5 to 3.0 kWhel, taking conservative value of 2KWelectric per 1 m3 biogas. So for 200KW for 12 hours, it needs 100x12=1200m^{3}biogas.As in Nepalese standard production of 0.317 kg/day/ person of MSW and 61%of those MSW are organic waste that can able to generate biogas. That means 0.19 Kg Organic waste per person per day.1 Ton of fresh mass from bio waste could be able to produce100m^3, that mean for 200kw 12Ton biodegradable waste is needed to produce 1200m^3 of biogas.

11 municipalities Biratnagar, Dang, Butwal, Dhangadhi, Itahari, Pokhara, and Ratnanagar municipality, shaded yellow in the table below has already conducted the feasibility study of the project under AEPC/SREP.

Table 22 : Cost analysis of biomass project with municipal waste

SN	GPA_NPA	District	State	Population	Plant Size (KW)	Area requirement (Sq. m)	Cost (Million NPR)
1	Bhadrapur	Jhapa	1	65533	211	1140	63.3
2	Birtamod	Jhapa	1	81878	263	1421	78.9
3	Damak	Jhapa	1	75102	241	1302	72.3
4	Mechinagar	Jhapa	1	111737	360	1944	108
5	Shivasataxi	Jhapa	1	64596	208	1124	62.4
6	Belbari	Morang	1	65892	212	1145	63.6
7	Biratnagar	Morang	1	214663	691	3732	207.3
8	Sundarharaicha	Morang	1	80518	259	1399	77.7
9	Dharan	Sunsari	1	137705	443	2393	132.9
10	Inaruwa	Sunsari	1	63593	204	1102	61.2
11	Itahari	Sunsari	1	140517	452	2441	135.6
12	Godawari	Lalitpur	3	78301	252	1361	75.6
13	Lalitpur	Lalitpur	3	284922	918	4958	275.4
14	Bhaktapur	Bhaktapur	3	81748	263	1421	78.9
15	MadhyapurThimi	Bhaktapur	3	83036	267	1442	80.1
16	Suryabinayak	Bhaktapur	3	78490	252	1361	75.6
17	Hetauda	Makawanpur	3	152875	492	2657	147.6
18	Bharatpur	Chitawan	3	280502	903	4877	270.9
19	Ratnanagar	Chitawan	3	69851	225	1215	67.5

20	Dhangadhi	Kailali	7	147741	476	2571	142.8
21	Tikapur	Kailali	7	76084	245	1323	73.5
22	Bhimdatta	Kanchanpur	7	104599	337	1820	101.1
23	Nepalgunj	Banke	5	138951	447	2414	134.1
24	Gulariya	Bardiya	5	66679	214	1156	64.2
25	Birendranagar	Surkhet	6	100458	323	1745	96.9
26	Pokhara Lekhnath	Kaski	4	402995	1298	7010	389.4
27	Kawasoti	Nawalparasi	4	62421	201	1086	60.3
28	Butwal	Rupandehi	5	138742	447	2414	134.1
29	Siddharthanagar	Rupandehi	5	63483	204	1102	61.2
30	Tillotama	Rupandehi	5	100149	322	1739	96.6
31	Kapilbastu	Kapilbastu	5	76394	246	1329	73.8
32	Krishnanagar	Kapilbastu	5	63453	204	1102	61.2
33	Lahan	Siraha	2	91766	295	1593	88.5
34	Siraha	Siraha	2	82531	265	1431	79.5
35	Bode Barsain	Saptari	2	65048	209	1129	62.7
36	Rajbiraj	Saptari	2	65855	212	1145	63.6
37	Gaur	Rautahat	2	68476	220	1188	66
38	Birgunj	Parsa	2	202240	651	3516	195.3
39	Gaushala	Mahottari	2	66677	214	1156	64.2
40	Budhanilakantha	Kathmandu	3	106920	344	1858	103.2
41	Chandragiri	Kathmandu	3	85198	274	1480	82.2

42	Gokarneshwor	Kathmandu	3	107351	345	1863	103.5
43	Kathmandu	Kathmandu	3	975453	3143	16973	942.9
44	Kirtipur	Kathmandu	3	65602	211	1140	63.3
45	Nagarjun	Kathmandu	3	67420	217	1172	65.1
46	Tarakeshwor	Kathmandu	3	81443	262	1415	78.6
47	Tokha	Kathmandu	3	100030	322	1739	96.6
48	Janakpur	Dhanusha	2	160268	516	2787	154.8
49	Kalaiya	Bara	2	122626	395	2133	118.5
50	Lumbini Sanskritik	Rupandehi	5	72497	233	1259	69.9

Note*: Biomass projects of which feasibility study completed under SREP (Sustainable Renewable Energy Program)

6.4 WIND

Using the available wind speed data of many places from the SWERA Report, 2008, a series of mathematical analysis were done to identify 3 proper sites for wind power generation.

Table 23 : Wind Speeds and Power Outputs for three proposed sites

S.N.	Site	Latitude	Longitude	Wind Speed at 10m (m/s)	Roughness Class	Wind Speed at 25m (m/s)	Pout at 25m (kW)
1	Thini	28.77	83.73	5.4	1.5	5.8	5.1984
2	Kagbeni	28.84	83.79	6.5	1.5	7.4	9.0664
3	Okhaldhunga	27.31	86.06	3.35	1	3.5	1.2411

Then the number of wind turbine units required were calculated based on the total power to be generated. The installation sites were marked using the computer software Google Earth Pro(see Annex). And finally, total energy units generated in an year were calculated assuming a suitable plant capacity factor.

With the help of empirical assumption that Rs. 198,250 is needed for constructing/installing a unit kW of wind power system, total cost required can be calculated.

Table 24 : Power and annual energy units generated by wind plants

S.N.	Place	Rated Power of single unit (kW)	Total Power to be generated (kW)	No of single units	Annual Energy Units generated (kWhr)
1	Thini	9	500	56	1728000
2	Kagbeni	18	500	28	1728000
3	Okhaldhunga	2	200	100	691200

Table 25 : Cost analysis of wind power

S.N.	Place	Rated Power of single unit (kW)	Total Power to be generated (kW)	Total Cost (Rs)
1	Thini	9	500	99,125,000
2	Kagbeni	18	500	99,125,000
3	Ramechhap	2	200	39,650,000

6.5 FINANCIAL ANALYSIS

6.5.1 Best DG Project Selection

Financial analysis considered unique local characteristics such as hydrology, road access, capacity utilization factor, transport costs, etc.; therefore, each Municipality had its own unique result. It was seen that Biomass had a LCOE of approx. NPR 9.56/ kWh and LBOE of approx. NPR 16.32/ kWh and ROE of 29%. High plant load factor, income from sale of electricity to NEA and additional income from sale of fertilizer byproduct results in a very attractive ROE for Biomass. Nonetheless, due to scarcity of well-established waste collection system, and pilot projects for testing business models; the second ranked DG project may have to be reconsidered. For Hydro, the selected projects had LCOE in the range of NPR 4/kWh to NPR 14/kWh, and LBOE of NPR 7/kWh. For Solar, the selected projects had LCOE in the range of NPR 11.96/kWh to NPR 14.40/kWh, and LBOE of NPR 6.98/kWh. For wind power, the LCOE was only calculated for 3 sites with on-site wind speed data. It was found that the LCOE was NPR 7.95/ kWh and LBOE was NPR 6.98/kWh. The LBOE was around NPR 7/kWh for Solar, Wind and Hydro as it was calculated based on the NPR 6/kWh Average NEA Tariff and 3% escalation for 8 years. For Solar, the ROE ranged from -3.6 to -0.8 % and for Wind Power it was around 6%. As none of the solar or wind project could deliver ROE of 15% or greater, VGF was considered for all of these projects. For Hydropower, the ROE ranged from -4 to 30 %. Only those Hydropower projects with ROE less than 15% were considered for VGF. The high capital costs and low capacity utilization factor of Solar PV in comparison to other technologies resulted in the lowest range of ROE. The summary of projects selected based on financial analysis is present in Table 26below.

Table 26 : Summary of Best DG Projects Selected (Province-wise and Country Total) for Base Case - Solar PV with 500 kWh battery storage

PROVINCE:	1	2	3	4	5	6	7	Country Total
Number of Hydro	54	-	33	25	16	45	48	**221**
Number of Solar PV	71	127	70	58	85	33	37	**481**
Number of Biomass	11	9	16	2	8	1	3	**50**
Number of Wind	1	-	-	-	-	-	-	**1**
Province Total	**137**	**136**	**119**	**85**	**109**	**79**	**88**	**753**

PROVINCE:	1	2	3	4	5	6	7	Country Total
Capacity of Hydro (MW)	43.0	-	26.4	22.4	12.6	43.1	44.9	**192.6**

Capacity of Solar PV (MW)	71.0	127.0	70.0	58.0	85.0	33.0	37.0	**481.0**
Capacity of Biomass (MW)	3.5	3.0	8.7	1.5	2.3	0.3	1.1	**20.4**
Capacity of Wind (MW)	0.2	-	-	-	-	-	-	**0.2**
Province Total (MW)	**117.8**	**130.0**	**105.1**	**81.9**	**99.9**	**76.5**	**83.0**	**694.2**

PROVINCE:	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**Country Total**
Investment for Hydro (M-NPR)	13,746	-	8,891	5,563	4,733	15,824	13,784	**62,541**
Investment for Solar PV (M-NPR)	11,712	20,912	11,559	9,586	14,020	5,512	6,126	**79,428**
Investment for Biomass (M-NPR)	1,063	893	2,607	450	695	97	317	**6,122**
Investment for Wind (M-NPR)	40	-	-	-	-	-	-	**40**
Province Total (M-NPR)	**26,562**	**21,805**	**23,057**	**15,598**	**19,448**	**21,433**	**20,228**	**148,131**

PROVINCE:	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**Country Total**
VGF for Hydro (M-NPR)	4,599	-	3,465	987	2,194	7,504	4,188	**22,937**
VGF for Solar PV (M-NPR)	7,909	13,970	7,853	6,230	8,896	3,291	3,782	**51,931**
VGF for Biomass (M-NPR)	-	-	-	-	-	-	-	**-**
VGF for Wind (M-NPR)	13	-	-	-	-	-		13
Province Total (M-NPR)	**12,521**	**13,970**	**11,318**	**7,217**	**11,090**	**10,795**	**7,970**	**74,881**

Table 27 : Average Investment and VGF of Best DG Projects Selected (Province-wise and Country overall) for Base Case – Solar PV with 500 kWh Storage

	Province 1	Province 2	Province 3	Province 4	Province 5	Province 6	Province 7	Country Average
Avg. Investment for Hydro (NPR/kW)	319,347	-	336,219	248,127	375,604	366,889	306,787	**324,772**
Avg. Investment for Solar PV (NPR/kW)	164,963	164,661	165,135	165,268	164,945	167,044	165,575	**165,132**
Avg. Investment for Biomass (NPR/kW)	300,000	300,000	300,000	300,000	300,000	300,000	300,000	**300,000**
Avg. Investment for Wind (NPR/kW)	198,250	-	-	-	-	-	-	**198,250**

	Province 1	Province 2	Province 3	Province 4	Province 5	Province 6	Province 7	Country Average
Avg. VGF for Hydro (NPR/kW)	106,838	-	131,032	44,036	174,074	173,985	93,216	**119,110**
Avg. VGF for Solar PV (NPR/kW)	111,394	110,000	112,186	107,414	104,659	99,727	102,216	**107,965**
Avg. VGF for Biomass (NPR/kW)	-	-	-	-	-	-	-	-
Avg. VGF for Wind (NPR/kW)	65,000	-	-	-	-	-	-	**65,000**

6.5.1.1 Province 1

In Province 1, based of Financial Analysis of identified projects, 54 Hydropower sites with total installed capacity of 43 MW, which was the highest number of Hydropower sites selected in a Province, 71 Solar PV sites with total installed capacity of 71 MW, 11 Biomass sites with total installed capacity of 3.5 MW and 1 Wind power site with total installed capacity of 0.2 MWwere selected.. The Total Investment required for Hydropower was NPR 13.74 billion, for Solar was NPR 11.71 billion (Base Case – 500 kWh Storage), for Biomass was NPR 1.06 billion and for Wind was NPR 40 million. Similarly, the Total VGF required for Hydropower was NPR

4.5 billion, for Solar was NPR 7.9 billion (Base Case – 500 kWh Storage) and for Wind was NPR 12 million. Since Biomass projects had an ROE above 15%, no VGF was required.

On average, the Investment required per kW for Hydro was NPR 319,347/ kW, for Solar was NPR 164,963/kW (Base Case – 500 kWh Storage), for Biomass was NPR 300,000/kW and for Wind was NPR 198,250/kW. On average, the VGF required per kW for Hydropower was NPR 106,838/kW, for Solar was NPR 111,394/kW (Base Case – 500 kWh Storage) and for Wind was NPR 60,000/kW.

6.5.1.2 Province 2

In Province 2, based of Financial Analysis of identified projects, 0 Hydropower sites, 127 Solar PV sites with total installed capacity of 127 MW, 9 Biomass sites with total installed capacity of 3 MW and 0 Wind power sites were selected. The Total Investment required for Solar was NPR 20.91 billion, and for Biomass was NPR 893 million. Similarly, the Total VGF required for Solar was NPR 13.9 billion. Since Biomass projects had an ROE above 15%, no VGF was required.

On average, the Investment required per kW for Solar was NPR 164,661/kW, and for Biomass was NPR 300,000/kW. On average, the VGF required per kW for Solar was NPR 110,000/kW. The highest number and installed capacity of Solar PV sites in the country were selected in Province 2 due to absence of any Hydropower sites.

6.5.1.3 Province 3

In Province 3, based of Financial Analysis of identified projects, 33 Hydropower sites with total installed capacity of 26.4 MW, 70 Solar PV sites with total installed capacity of 70 MW, 16 Biomass sites with total installed capacity of 8.7 MW and 0 Wind power sites were selected.. The Total Investment required for Hydropower was NPR 8.89 billion, for Solar was NPR 11.55 billion, and for Biomass was NPR 2.6 billion. Similarly, the Total VGF required for Hydropower was NPR 3.4 billion, and for Solar was NPR 7.8 billion. Since Biomass projects had an ROE above 15%, no VGF was required.

On average, the Investment required per kW for Hydro was NPR 336,219/ kW, for Solar was NPR 165,135/kW, and for Biomass was NPR 300,000/kW. On average, the VGF required per kW for Hydropower was NPR 131,032/kW, and for Solar was NPR 112,186/kW. The highest number of Biomass project sites in the country were selected in Province 3.

6.5.1.4 Province 4

In Province 4, based of Financial Analysis of identified projects, 25 Hydropower sites with total installed capacity of 22.4 MW, 58 Solar PV sites with total installed capacity of 58 MW, 2 Biomass sites with total installed capacity of 1.5 MW and 0 Wind power sites were selected.. The Total Investment required for Hydropower was NPR 5.56 billion, for Solar was NPR 9.58 billion, and for Biomass was NPR 450million. Similarly, the Total VGF required for Hydropower was NPR 987million, and for Solar was NPR 6.2 billion. Since Biomass projects had an ROE above 15%, no VGF was required.

On average, the Investment required per kW for Hydro was NPR 248,127/ kW, which was the lowest in the country for Hydropower, for Solar was NPR 165,268/kW, and for Biomass was NPR 300,000/kW. On average, the VGF required per kW for Hydropower was NPR 44,036/kW, which was the lowest in the country for Hydropower, and for Solar was NPR 107,414/kW.

6.5.1.5 Province 5

In Province 5, based of Financial Analysis of identified projects, 16 Hydropower sites with total installed capacity of 12.6 MW, 85 Solar PV sites with total installed capacity of 85 MW, 8 Biomass sites with total installed capacity of 2.3 MW and 0 Wind power sites were selected.. The Total Investment required for Hydropower was NPR 4.73 billion, for Solar was NPR 14.02 billion, and for Biomass was NPR 695 million. Similarly, the Total VGF required for Hydropower was NPR 2.1 billion, and for Solar was NPR 8.8 billion. Since Biomass projects had an ROE above 15%, no VGF was required.

On average, the Investment required per kW for Hydro was NPR 375,604/ kW, which was the highest in the country for Hydropower, for Solar was NPR 164,945/kW, and for Biomass was NPR 300,000/kW. On average, the VGF required per kW for Hydropower was NPR 174,074/kW, which was the highest in the country for Hydropower, and for Solar was NPR 104,659/kW. The second highest number of Solar sites and second lowest number of Hydropower sites in the country were selected in Province 5.

6.5.1.6 Province 6

In Province 6, based of Financial Analysis of identified projects, 45 Hydropower sites with total installed capacity of 43.1 MW, 33 Solar PV sites with total installed capacity of 33 MW, 1 Biomass sites with total installed capacity of 0.3 MW and 0 Wind power sites were selected.. The Total Investment required for Hydropower was NPR 15.84 billion, for Solar was NPR 5.5 billion, and for Biomass was NPR 97 million. Similarly, the Total VGF required for Hydropower was NPR 7.5 billion, and for Solar was NPR 3.2 billion. Since Biomass projects had an ROE above 15%, no VGF was required.

On average, the Investment required per kW for Hydro was NPR 366,889/ kW, for Solar was NPR 167,044/kW, and for Biomass was NPR 300,000/kW. On average, the VGF required per kW for Hydropower was NPR 173,985/kW, and for Solar was NPR 99,727/kW which was the lowest in the country for Solar.

6.5.1.7 Province 7

In Province 7, based of Financial Analysis of identified projects, 48 Hydropower sites with total installed capacity of 44.9 MW, which was the highest installed capacity for Hydropower selected in a Province, 37 Solar PV sites with total installed capacity of 37 MW, 3 Biomass sites with total installed capacity of 1.1 MW and 0 Wind power sites were selected.. The Total Investment required for Hydropower was NPR 13.78 billion, for Solar was NPR 6.1 billion, and for Biomass was NPR 317 million. Similarly, the Total VGF required for Hydropower was NPR 4.1 billion, and for Solar was NPR 3.7 billion. Since Biomass projects had an ROE above 15%, no VGF was required.

On average, the Investment required per kW for Hydro was NPR 306,787/ kW, for Solar was NPR 165,575/kW, and for Biomass was NPR 300,000/kW. On average, the VGF required per kW for Hydropower was NPR 93,216/kW, and for Solar was NPR 102,216/kW.

6.5.1.8 Overall Country

Based on Financial Analysis of identified projects, overall 221 Hydropower sites with total installed capacity of 192.6 MW, 481 Solar PV sites with total installed capacity of 481 MW, 50 Biomass sites with total installed capacity of 20.4 MW and 1 Wind power site with installed capacity of 0.2 MW were selected.. The Total Investment required for Hydropower was NPR 62.54 billion, for Solar was NPR 79.42 billion, and for Biomass was NPR 6.12 billion, and for Wind was NPR 40 million; thus, the Total Investment necessary for whole country was NPR 148.13 billion.

Since Biomass projects had an ROE above 15%, no VGF was required for these projects. The Total VGF required for Hydropower was NPR 22.9 billion, and for Solar was NPR 51.9 billion, for Wind was NPR 12 million; thus, the Total VGF necessary for whole country was NPR 74.88 billion.

On average, the Investment required per kW for Hydro was NPR 324,772/ kW, for Solar was NPR 165,132/kW, and for Biomass was NPR 300,000/kW. On average, the VGF required per kW for Hydropower was NPR 119,110/kW, and for Solar was NPR 107,965/kW.

6.5.1.9 Alternative Cases of Investment and VGF – Solar with 200 kWh or No battery storage

Table 28 : Summary of Best DG Projects Selected (Province-wise and Country Total) for Alternative Scenario – Solar PV with 200 kWh battery storage

PROVINCE:	1	2	3	4	5	6	7	Country Total
Investment for Hydro (M-NPR)	13,746	-	8,891	5,563	4,733	15,824	13,784	**62,541**
Investment for Solar PV (M-NPR)	10,334	18,452	10,199	8,458	12,371	4,864	5,405	**70,084**
Investment for Biomass (M-NPR)	1,063	893	2,607	450	695	97	317	**6,122**
Investment for Wind (M-NPR)	40	-	-	-	-	-	-	**40**
Province Total (M-NPR)	**25,183**	**19,345**	**21,697**	**14,471**	**17,799**	**20,785**	**19,507**	**138,787**

PROVINCE:	1	2	3	4	5	6	7	Country Total
VGF for Hydro (M-NPR)	4,599	-	3,465	987	2,194	7,504	4,188	**22,937**
VGF for Solar PV (M-NPR)	6,112	10,795	6,068	4,814	6,874	2,543	2,922	**40,129**
VGF for Biomass (M-NPR)	-	-	-	-	-	-	-	**-**
VGF for Wind (M-NPR)	13	-	-	-	-	-		**13**
Province Total (M-NPR)	**10,724**	**10,795**	**9,533**	**5,801**	**9,068**	**10,047**	**7,110**	**63,079**

Table 29 : Summary of Best DG Projects Selected (Province-wise and Country Total) for Alternative Scenario – Solar PV without Battery

PROVINCE:	1	2	3	4	5	6	7	Country Total
Investment for Hydro (M-NPR)	13,746	-	8,891	5,563	4,733	15,824	13,784	**62,541**
Investment for Solar PV (M-NPR)	8,518	15,209	8,407	6,972	10,196	4,009	4,455	**57,766**
Investment for Biomass (M-NPR)	1,063	893	2,607	450	695	97	317	**6,122**
Investment for Wind (M-NPR)	40	-	-	-	-	-	-	**40**
Province Total (M-NPR)	**23,367**	**16,102**	**19,905**	**12,985**	**15,624**	**19,930**	**18,557**	**126,469**

PROVINCE:	1	2	3	4	5	6	7	Country Total
VGF for Hydro (M-NPR)	4,599	-	3,465	987	2,194	7,504	4,188	**22,937**
VGF for Solar PV (M-NPR)	4,314	7,620	4,283	3,398	4,852	1,795	2,063	**28,326**
VGF for Biomass (M-NPR)	-	-	-	-	-	-	-	**-**
VGF for Wind (M-NPR)	13	-	-	-	-	-		**13**
Province Total (M-NPR)	**8,926**	**7,620**	**7,748**	**4,385**	**7,046**	**9,299**	**6,251**	**51,276**

Table 28 and Table 29 show that changes in Total Investment and VGF required for Alternative Scenarios of Solar PV with 200 kWh battery and NO battery storage respectively. As can be seen from the tables, the Total Investment decreases significantly from NPR 148 Billion for Base Case of Solar PV with 500 kWh battery to NPR 138 Billion and NPR 126 Billion for Alternative Scenarios of Solar PV with 200 kWh battery and NO battery storage respectively. Similarly the Total Viability Gap Funding (VGF) decreases significantly from NPR 74 Billion for Base Case of Solar PV with 500 kWh battery to NPR 63 Billion and NPR 51 Billion for Alternative Scenarios of Solar PV with 200 kWh battery and NO battery storage respectively. On average, the VGF required per kW for Solar with 200 kWh was approx. NPR 85,000 and for Solar with NO battery storage was approx. NPR 60,000. Nonetheless, these scenarios with less or no battery storage would comprise on the aspect of electricity reliability in case the central grid is down during the evening or nights.

6.5.2 Cost of Grid Extension with and without DG

Cost of Grid Extension with DG for all the Seven Provinces have been calculated and without DG only for Province 1 has been calculated and the summary is presented in tabulated below. Detailed summary of cost estimate is attached in Annex D.

Table 30 : Cost of Grid Extension with DG for Province 1

Proposed 33/11 KV Substations	Proposed 11 KV Switching Substations	Proposed 132/33 KV Substations	Proposed 132 KV Line length (km)	Proposed 33 KV Line length (km)	Proposed 11 KV Line length (km)	Cost Estimate (NPR in million)
51	36	4	54.5	930.55	427.7	9432.6

Table 31 : Cost of Grid Extension with DG for Province 2

Proposed 33/11 KV Substations	Proposed 11 KV Switching Substations	Proposed 132/33 KV Substations	Proposed 132 KV Line length (km)	Proposed 33 KV Line length (km)	Proposed 11 KV Line length (km)	Cost Estimate (NPR in million)
69	33	3	93.3	1070.6	191.6	11818

Table 32 : Cost of Grid Extension with DG for Province 3

Proposed 33/11 KV Substations	Proposed 11 KV Switching Substations	Proposed 132/33 KV Substations	Proposed 132 KV Line length (km)	Proposed 33 KV Line length (km)	Proposed 11 KV Line length (km)	Cost Estimate (NPR in million)
48	26	-	-	712.7	224.45	7110.4

Table 33 : Cost of Grid Extension with DG for Province 4

Proposed 33/11 KV Substations	Proposed 11 KV Switching Substations	Proposed 132/33 KV Substations	Proposed 132 KV Line length (km)	Proposed 33 KV Line length (km)	Proposed 11 KV Line length (km)	Cost Estimate (NPR in million)
33	21	-	-	555.45	265	5089

Table 34 : Cost of Grid Extension with DG for Province 5

Proposed 33/11 KV Substations	Proposed 11 KV Switching Substations	Proposed 132/33 KV Substations	Proposed 132 KV Line length (km)	Proposed 33 KV Line length (km)	Proposed 11 KV Line length (km)	Cost Estimate (NPR in million)
52	15	1	48.4	669.05	152.25	7610.3

Table 35 : Cost of Grid Extension with DG for Province 6

Proposed 33/11 KV Substations	Proposed 11 KV Switching Substations	Proposed 132/33 KV Substations	Proposed 132 KV Line length (km)	Proposed 33 KV Line length (km)	Proposed 11 KV Line length (km)	Cost Estimate (NPR in million)
32	38	-	-	835	510	6548.5

Table 36 : Cost of Grid Extension with DG for Province 7

Proposed 33/11 KV Substations	Proposed 11 KV Switching Substations	Proposed 132/33 KV Substations	Proposed 132 KV Line length (km)	Proposed 33 KV Line length	Proposed 11 KV Line length (km)	Cost Estimate (NPR in million)

				(km)		
38	30	-	-	795.05	292.9	6194

It was found that generally the number of 33/11 kV SS were highest for each province, followed by 11 kV Switching SS and 132/33 kV Substations. This was expected as 33/11 kV Substation was proposed for each Municipality as a development hub, followed by 11 kV for primary distribution. In case the 33 kV double circuit lines were not enough to handle the load, 132 kV substations were proposed. 132 kV Substations were only proposed in Provinces where NEA has insufficient number of Substations.

It was found that the length of the 33 kV lines were highest for each province, followed by 11 kV lines and 132 kV lines. In Province 2, the length of 33 kV lines was highest among the Provinces because there were a large number of high load centers compared to other Provinces which required longer lengths of higher current carrying capacity 33 kV Lines.

Overall, highest number of 33/11 kV Substations were proposed, followed by 11 kV Substations for primary distribution. The share of 132 kV substations were the lowest as they were considered only when 33/11 kV Substations were insufficient. Overall, it was found that the length of the 33 kV lines were highest, followed by 11 kV lines and 132 kV lines. 33 kV lines were highest because they were found to be most suitable to service the load centers. 132 kV lines were the lowest as they were only considered when even double circuit 33 kV lines were insufficient.

The Cost of 33/11 kV Substations were highest for each Province due to their greater share. The cost of 33 kV lines were highest for each Province due to their greater share. In Province 2, the cost of 33 kV lines was highest among the Provinces because of larger length line required to service greater number of high load centers compared to other Provinces. It was found that the overall cost was highest for Province 2 due to larger length of 33 kV lines required. Moreover, the cost of Substations was higher than that of T&D lines for each Province. Overall, the total cost of Grid Extension was NPR 56.37 Billion, of which Substations accounted for almost 72% of the total cost due to high cost of Transformers and associated equipment used in a Substation.

6.6 ECONOMIC ANALYSIS

Table 37 : Results of Economic Analysis and Sensitivity Analysis

Scenario / Economic Indicators	Province 1		Province 2	
	Scenario A: Grid Extension with DG	**Scenario B: Grid Extension without DG**	**Scenario A: Grid Extension with DG**	**Scenario B: Grid Extension without DG**
	Network Loss = 9%	Network Loss = 18%	Network Loss = 9%	Network Loss = 18%
Base Case: SDR = 2%				
NPV (NPR- Billion)	736	671	940	861
EIRR	39.33%	39.36%	42.54%	43.03%
PBP (years)	2.54	2.53	2.35	2.32
Case I: SDR = 5%				
NPV (NPR- Billion)	642	456	643	589
Case II: SDR = 8%				
NPV (NPR- Billion)	352	321	455	418

Economic Analysis is undertaken for two representative models of dispersed generation (Province 1) and high load density (Province 2) and comparison is made between economic scenario of each Province for Grid Extension with and without DG.

Scenario A considers Grid Extension with DG, which includes Capital and O&M costs of selected DG plants, T&D Network expansion and necessary Central Hydro plants to completely supply the load. For this scenario, Transmission & Distribution Network Loss is considered as 9%. Scenario B considers Grid Extension without DG, which includes Capital and O&M costs of T&D Network expansion and Central Hydro plants that can supply same level energy as the previous scenario. For this scenario, Transmission & Distribution Network Loss is considered as 18%.

Social/Economic Discount Rate (SDR) is assumed to be 2%, which is calculated by averaging the interest on Treasury-bills (364 days) over a period of 4 years (15 data points) as published by Nepal Rastriya Bank (Quarterly Economic Bulletin, July 2017) and adding 0.7% for market distortion. Economic analysis is performed for project lifetime of 25 years.

6.6.1 Province 1

In Province 1, 54 Hydropower sites with total installed capacity of 43 MW (which was the highest number of Hydropower sites selected in a Province), 71 Solar PV sites with total installed capacity of 71 MWp, 11 Biomass sites with total installed capacity of 3.5 MW and 1 Wind power site with total installed capacity of 0.2 MW were selected through financial analysis. As shown in Table 37 for the Base Case (SDR = 2%) of Province 1, the Net Present Value (NPV) is highest for Scenario A: Grid Extension with DG at NPR 736 billion. Scenario B: Grid Extension without DG yields lower NPV of NPR 671 billion. Similarly, both Scenarios have similar Economic Internal Rate of Return (EIRR) of approximately 39% and Pay Back Period (PBP) of approx. 2.5 years. As Economic evaluation considers the NPV while ranking projects, i.e. the net value added to the economy, Grid Extension with DG is recommended for Province 1.

Sensitivity Analysis at higher SDR of 5% (Case I) shows that that NPV decreases to NPR 642 billion for Scenario A and to NPR 456 billion for Scenario B; nonetheless, the net economic value added is still higher for Scenario A. Similarly, Sensitivity Analysis at highest SDR of 8% (Case II) shows that that NPV decreases to NPR 352 billion for Scenario A and to NPR 321 billion for Scenario B; nonetheless, the net economic value added is still higher for Scenario A. Also, preliminary analysis shows that the results of economic analysis for Provinces 3, 4, 5, 6 & 7 would be similar to that of Province 1 (due to similar load and generation profile).

6.6.2 Province 2

In Province 2, no hydropower sites were found. 127 Solar PV sites with total installed capacity of 127 MWp, and 9 Biomass sites with total installed capacity of 3 MW were selected through financial analysis. The highest number and installed capacity of Solar PV sites in the country were selected in Province 2 due to absence of any Hydropower potential. Also, the load was the highest for Province 2 due to high population density. As can be seen from the Table 37 for the Base Case (SDR = 2%) of Province 2, the NPV is highest for Scenario A: Grid Extension with DG at NPR 940 billion. Scenario B: Grid Extension without DG yields lower NPV of NPR 861 billion. Similarly, both Scenarios have similar EIRR of approximately 43% and Pay Back Period (PBP) of approx. 2.3 years. As Economic evaluation considers the NPV while ranking projects, i.e. the net value added to the economy, Grid Extension with DG is recommended for Province 2 as well.

Sensitivity Analysis at higher SDR of 5% (Case I) shows that that NPV decreases to NPR 643 billion for Scenario A and to NPR 589 billion for Scenario B; nonetheless, the net economic value added is still higher for Scenario A. Similarly, Sensitivity Analysis at highest SDR of 8% (Case II) shows that that NPV decreases to NPR 455 billion for Scenario A and to NPR 418 billion for Scenario B; nonetheless, the net economic value added is still higher for Scenario A.

The economic model captures the following elements: (i) Reduction of Capital and Operational expenditure of Transmission and Distribution networks (Grid Extension) due to active and reactive power support by DG plants (ii) Reduction of Network Losses due to DG plants servicing local loads and improvement in grid voltage and performance, and (iii) Economic benefits from fuel replacement and willingness to pay according to the electrification status of the Municipality.

However, due to limitations of time and scarcity of published local research, additional economic benefits of Grid Extension with DG such as (i) fewer social and environmental consequences over large central plants, and (ii) ripple economic effect through forward and backward economic linkages that can kick-start the local economy could not be captured in the model. If they were to be considered, the NPV and EIRR of Scenario A: Grid Extension with DG would be higher for all Provinces.

Further, economic costs of GHG emissions over the project lifetime is not considered. Over the project lifetime, GHG emissions of hydropower would be slightly higher (diesel usage over longer construction period and low-level emissions from submerged plants) than Solar PV, but both of these renewable technologies would have minimal GHG emissions when compared to fossil fuel plants such as coal or gas fired plants. Benefits of GHG mitigation are also not considered in the model; the NPV and EIRR would increase for both Scenarios if they were to be considered.

6.7 FIELD VISIT

A comprehensive report from the Biomass, Hydropower, Solar and Electrical Experts based on the information collected by site engineers from the site visits.

S.N.	Team No:	Districts	Hydropower, Electrical and Solar Findings
1	Team 1	Taplejung, Ilam, Panchthar, Jhapa, Morang, Sunsari	The Team Visited all the districts. The General Findings are as followings. 1. In Terai Districts like Sunsari , Jhapa and Morang, in general, there is no potential of hydropower for range (500 kW to 1 MW installed Capacity. 2. From Large Hydro Projects Perspective, still there might be potential linked with the Hydropower Development in Koshi River. 3. In hilly districts, (Taplejung, Panchthar, and Ilam) there is potential of hydropower projects from mini hydro to large hydro size). 4. Some hydro projects have been constructed and some projects under construction in Taplejung, Panchthar and Ilam. 5. Regarding Transmission line, planned transmission line and distribution line needs to be developed. 6. Most of the area has been electrified by Grid and off grid means and reliable Grid Access to all is the main need in these districts.
2	Team 2	Dhankuta, Terhathum, Sankhuwasabha and Bhojpur	The Team Visited all the districts. The General Findings are as followings. 1. In all the districts, there is still the potential of hydro development in the range of 500 kW to 1 MW installed capacity. 2. Shankhuwasabha and Bhojpur have large hydropower potential (Arun River Basin). Similarly there is also hydro potential in Terhathum and Dhankuta. 3. Hydropower Projects are in construction (especially private sector working) and a few hydro projects already constructed. 4. Some of the local areas have been electrified by micro hydro projects as well. 5. Regarding Transmission line, planned transmission line and distribution line needs to be developed. 6. Still the remote parts of Sankhuwasabha, Bhojpur, Terhathum and Bhojpur still waiting for electrification. Reliable Grid Access to all is the main need in these districts.
3	Team 3	Sindhuli, Okhaldhunga, Solukhumbu, Khotang, Udaypur	The Team Visited all the districts. The General Findings are as followings. 1.Sindhuli and Udaypur are the districts with low hydro potential. 2. There is hydro potential (mini to Large) in Okhaldhunga, Solukhumbu and Khotang Districts. 3. Micro Hydro Projects have electrified some of the remote parts of Sindhuli, Okhaldhunga, Solukhumbu and Khotang. 4. Regarding Transmission line, planned transmission line and distriution line needs to be developed. 5. Still the remote parts of Solukhumbu and Khotang, districts electrification is either to be made or electrified with alternative

			Energy technologies. Reliable Grid Access to all is the main need in these districts.
4	Team 4	Dolakha, Ramechhap, Sindhupalchowk Kavreplanchowk	The Team Visited all the districts. The General Findings are as followings. 1.To some extent, there is potential of hydropower projects of this range in all district. 2.There are a number of projects constructed or under construction in Dolakha, Sindhupalchowk, Ramechhap and Kavreplanchowk Districts. 3. Since there are huge projects under construction in Dolakha, there might be less probability of promoting projects of this range and the same case may apply in these districts. 4. Micro Hydro Projects have electrified some of the remote parts of all the districts. 5. Regarding Transmission line, planned transmission line and distribution line needs to be developed. 6. Most part of the districts have electricity. The major concern is the quality (Appropriate size of transformers, poles etc.). Reliable Grid Access to all is the main need in these districts.
5	Team 5	Rasuwa, Nuwakot, Dhading, Lalitpur, Kathmandu, Bhaktapur	The Team Visited Rasuwa, Nuwakot and Dhading District and the findings is as followings. 1.To some extent, there is potential of hydropower projects of this range in all of these districts. 2.There are a number of projects constructed or under construction (Medium and Large Hydro) in Rasuwa, Nuwakot and Dhading Districts. 3. Some parts of the districts have been electrified by Micro Hydro Projects as well. 4. Regarding Transmission line, planned transmission line and distriution line needs to be developed. 6. Most part of the districts has electricity. The major concern is the quality (Appropriate size of transformers, poles etc.). Reliable Grid Access to all is the main need in these districts.
6	Team 6	Gorkha, Tanahu, Lamjung Manang , Kaski	The Team all the districts and major findings are as followings. 1.There is no potential of hydro of this range in Tanahun District. In Kaski as well, very few nos. of such projects are available. There is potential of hydro projects in medium and Large hydro category. 2.There are a number of projects constructed or under construction (Medium and Large Hydro) in the districts. 3. Some parts of the districts have been electrified by Micro Hydro Projects as well. 4. Regarding Transmission line, planned transmission line and distribution line needs to be developed. 6. Most part of the districts has electricity. The major concern is the quality (Appropriate size of transformers, poles etc.). Reliable Grid Access to all is the main need in these districts.

7	Team 7	Mustang, Parbat, Myagdi, Baglung	The Team all the districts and major findings are as followings. 1.There is potential of hydro of this range in Mustang, Myagdi and Baglung Districts. There is almost no potential in Parbat district although one site have been found in desk study. 2.In Parbat almost all the areas have been covered by National Grid and the quality issue is the main issue there. 3. About 50% of the parts have been electrified by National Grid and the most of rest part have been electrified micro hydro in Myagdi district. Still some villages have to be electrified there. There are a number of micro hydro projects in operation. 4. In Baglung, there is grid access in about 40% of the population and the rest electrified by Micro Hydro. Huge work still to be made in Baglung for Grid Access. Baglung have more than 100 micro hydro projects which are in running condition now as well. 5. In Mustang District, Grid Extension has been made from Dana Tatopani and the upper Mustang area still needs to be electrified. 6. Reliable Grid Access to all is the main need in these districts.
8	Team 8	Syanja, Gulmi, Palpa, Arghakhanchi, Nawaplarasi	The Team Visited all the districts. The General Findings are as followings. 1.In all of these districts, there is very less potential of hydropower of this range. 2.There is no potential of hydro of this range in Arghakhanchi and Nawalparasi. 3. There are some existing hydropower projects in Syanja, Gulmi and Palpa. There is potential of Large hydro projects in Syanja, Gulmi, Palpa, Arghakhanchi and in Nawalparasi. 4. Micro Hydro Projects have electrified some of the remote parts of Syangja, Gulmi, Palpa and Arghakhanchi Districts. 5. Regarding Transmission line, planned transmission line and distriution line needs to be developed. 6. Most part of the districts has electricity. The major concern is the quality (Appropriate size of transformers, poles etc.). Reliable Grid Access to all is the main need in these districts.
9	Team 9	Rolpa, Rukum, Salyan, Pyuthan and Dang	The Team Visited all the districts. The General Findings are as followings. 1.There is potential of hydro projects of this range in Rolpa and Rukum Districts. 2. Salyan and Pyuthan have average potential in this range. 3. There is possibility of promoting large hydropower projects (Rolpa, Rukum and Pyuthan). 4. Micro Hydro Projects have electrified some of the remote parts of Rukum, Rolpa and Pyuthan. 5. Regarding Transmission line, planned transmission line and distribution line needs to be developed. 6. Still electrification is to be made in Rukum (East and West Both). 7. Reliable Grid Access to all is the main need in these districts.

10	Team 10	Surkhet, Dailekh, Jajarkot	The Team Visited all the districts. The General Findings are as followings. 1. There is potential of hydro projects of this range in all the districts. 2. There is possibility of promoting large hydropower projects as well. 3. Very few no. of large hydropower projects have been developed in these districts (One project developed in Dailekh and one Project under construction in Dailekh). 4. Micro Hydro Projects have electrified some of the remote parts of all the districts. 5. Regarding Transmission line, planned transmission line and distribution line needs to be developed. 6. Still electrification is to be made in parts of all the districts. 7. Reliable Grid Access to all is the main need in these districts.
11	Team 11	Mugu, Jumla, Kalikot, Banke and Bardiya	The Team Visited all the districts. The General Findings are as followings. 1.There is potential of hydro projects of this range in Mugu, Jumla and Kalikot Districts. 2. There is possibility of promoting large hydropower projects as well. 3. Till now no large hydro projects have been developed. 4. Micro Hydro Projects have electrified some parts of the districts in Mugu, Jumla and Kalikot districts. 5. Regarding Transmission line, No Grid Connection is still made in Mugu, Jumla and Kalikot Districts. 6. Still electrification is to be made in parts of all the districts and the only available option is the off grid electricity for now. 7. Electrification expansion is the main need in these districts. In Case of Banke and Bardiya, quality electrification is the main issue.
12	Team 12	Dolpa, Humla	The Team Visited all the districts. The General Findings are as followings. 1.There is potential of hydro projects of this range in both the districts. 2. There is possibility of promoting large hydropower projects as well. 3. Till now no large hydro projects have been developed. 4. Micro Hydro Projects have electrified some parts of the districts in Dolpa and Humla. 5. Regarding Transmission line, No Grid Connection is still made in these districts. 6. Still electrification is to be made in parts of all the districts and the only available option is the off grid electricity for now.
13	Team 13	Dadeldhura, Doti, Acham, Bajura	The Team Visited all the districts. The General Findings are as followings. 1.There is potential of hydro projects of this range in all the districts. 2. There is possibility of promoting large hydropower projects as well.

			3. Till now no large hydro projects have been developed. 4. Dadeldhura, Doti and Achham have the partial grid connectivity and off grid micro hydro projects have electrified the most part of the remaining districts. 5. Regarding Transmission line, Bajura has no access to National Grid. 6. Access to energy is still the main issue and lots of work needs to be done in grid extension.
14	Team 14	Bajhang, Darchula, Baitadi, Kanchanpur, Kailali	The Team Visited all the districts. The General Findings are as followings. 1.There is potential of hydro projects of this range in Bajhang, Darchula and Baitadi districts. 2. There is possibility of promoting large hydropower projects as well. 3. Chameliya Hydropower project has recently been connected to National Grid. 4. Partial Grid connection is made in all the districts. 5. Micro Hydro has electrified the most part of Bajhang, Darchula and Baitadi districts. 6. Access to energy is still the main issue and lots of work needs to be done in grid extension.
15	Team 15	Chitwan, Makwanpur, Parsa, Bara, Rautahat	The Team Visited all the districts. The General Findings are as followings. 1.There is potential of hydro projects of this in Makwanpur District only. 2. There is possibility of promoting large hydropower projects in Chitwan and Makwanpur District. 3. Kulekhani I and II Hydropower Projects (60 MW and 32 MW) already operation in Makwanpur District. 4. Grid connection is made in most of the parts of all the districts. 5. Micro Hydro has electrified some parts in Makwanpur district. 6. Quality Grid Access is the main issue in these districts.
16	Team 10	Dhanusha, Mahottari, Saptari	The Team Visited all the districts. The General Findings are as followings. 1. There is no potential of Hydropower projects in these districts with the assumptions adopted. 2. There might be possibility of promoting low head turbines in irrigation canals and the rivers. 3. There might be possibility of promoting reservoir type low head projects in the districts nearer to Chure Region. 4. Kamala River (Dhanusa) situated at Ganesman Charnath can be considered for the study of hydro energy production. 6. Voltage quality is the main issue with the existing distribution system in these districts. 5. Quality Grid Expansion is the main issue in these districts. 6. Greater issues with expansion of LT lines and 11kV and 33kV lines due to physical structures within the city areas of all the districts. So, underground system up to 33kV system will be the

			best option for the expansion panning. 7. Requirement of isolated solar plant at Gobargada (Hanumannagar Kankalini Municipality) as the grid expansion seems impossible to the place as it is surrounded by the Koshi River from all the sides with around 200 households residing in that area. 8. Provision of electricity for the agriculture and irrigation purposes in these districts need to be considered.

SN	Provience	District	Possible Sites	Biomass Findings
1	1	Jhapa	Bhadrapur, Birtamod, Damak, Mechinagar, Shivasataxi	ln Birtamod, Bio gas project is planned but not implemented from public toilets. All waste is dumped near river. The average rate of land in Gaupalika is about 3 lakhs per katha and forNagarpalika is about 30 lakhs per katha. More waste is generated from tea plant and ply factory which can be used for Biomass energy.
2	1	Morang	Belbari, Biratnagar, Sundarharaicha	The average rate of land in Gaupalika is about 50-60 lakh per bigha and for Nagarpalika is about 60-70 lakh per katha. In Biratnagar-t4, Biomass plant is under construction which will be completed in Falgun, 2074 from which upto 400 houses will be provided with gas facilities by pipeline. ln Morang Prison, 5KW energz is generated from the waste. Tariff per household is Rs 250 per month for waste management
3	1	Sunsari	Dharan, Inaruwa, Itahari	The district is almost electrified. There is dumping site in each Gaupalika or Nagarpalika. Dharan dumps waste near Seuti Khola. Itahari and Dharan is planning to generate waste to energy.Tariff per household is Rs 100-120 per month for waste

				management.Duhabi,Itahari, Dharan, lnarwa and Bhashi has possibility of biomass project. Inaruwa, Duhabi, Bhasi is planning to sell their waste to Biratnagar for biomass energ/ generation.
4	1	Illam		Landfill is practice in Illam & fikkal area, while dumping is done in different area
5	1	Panchathar	Phidim	Phidim can be possible site for biomass project as the population of Phidim is near 60,000. The yearly expenditure for biowaste disposalis about Rs 15-20lakh and daily quantity of waste generated is about 2 ton. Dumping is practice for waste management in Panchthar.
6	2	Dhanusha	Janakpur	There is no proper plan and particular site regarding waste management and treatment. Existing practice for waste disposal is collecting from door to door and dumping in any empty place nearby.
7	2	Mahottari	Gaushala	No particular site and plan for waste disposal.
8	2	Parsa	Birgunj	
9	2	Rautahat	Gaur	
10	2	Saptari	Bode Barsain, Rajbiraj	No particular site and plan for waste disposal. Not any future plans for bioplants.
11	2	Siraha	Lahan, Siraha	

12	3	Chitawan	Bharatpur, Ratnanagar	Private company collects waste and recycles it. About 1 quintal waste is dumped per month from 1 househols. A popular site for dumping waste is under Narayani bridge. No bio-gas/waste projects are planned as per the site visit report. People give Rs. 50 per month to Tole Sudhaar Samiti. People do mass cleanliness ever Saturday mornings.
13	3	Kathmandu	Budhanilakantha, Chandagiri, Gokarneshor, Kathmandu, Kirtipur, Nagarjun, Tarakeshor, Tokha	
14	3	Lalitpur	Godawari, Lalitpur	
15	3	Makawanpur	Hetauda	About 24 ton of waste is disposed per day and more than 1.5 crore is spent annually for sweeping alone .Methods of dumping waste are landfill and sites are Rapti bridge and Sisaubhari. Few practice bio gas Land given by municipality 12 years ago. Private developer called after completion of feasibility study. .
16	4	Kaski	Pokhara Lekhnath	No any plans for bio energy generation. Municipality collects waste from every household twice a week and collects about Rs. 300 from every household.
17	4	Nawalparasi	Kawasoti	The site identified for waste disposal are Parsai Pul Pari and Sariya in kawasoti. Possibility of bio-energy generation but not happening due to conflict among people

18	4	Tanahun		There is possibility of biomass project in Byas Municipality Tekanthumki community forest area
19	5	Banke	Nepalgunj	About 35 ton of waste is collected perday from door to door collection and road cleaning/sweeping. The average rate of land in Gaupalika is about 10 lakh per kaththaa. Waste to energy project (AEPC) is under feasibility stage
20	5	Kapilbastu	Kapilbastu, Krishnanagar	
21	5	Rupandehi	Butwal, Siddharthanagar, Tillotama, Lumbini Sanskritik	Possibility of biomass projects. Existing practice of waste management are temporary landfill and incineratin. Municipalities are also collecting Rs 50-60 per month in the district.
22	7	Kailali	Dhangadhi, Tikapur	For Biomass project, Bidding was already made and only Dhangadhi municipality need to provide the required area of land to the contractor
23	7	Kanchanpur	Bhimdatta	Two Sugar mills in district produce 3-5 MW electricity and the use only 4-6 month in a year. They expect coordination form us to connect the produced electricity in national grid

Note: District wise details have been included along with the summary report. See Annex O for detailed field visit findings.

7 CONCLUSION& RECOMMENDATIONS

7.1 HYDROPOWER

In case of design discharge, Q45 was adopted initially and accordingly in province-1, 85 local bodies with hydro and 52 local bodies without hydro sites were identified. If adopted Q45, more sites for many local bodies all over the country could be identified. However existing water use information for all the identified sites were not available in this stage of study. Therefore, based on the expert's opinion in the meeting held on 11th October, 2017 in the office of NEAEC, Q65 as design discharge has been adopted, keeping in view of water right perspective.

During the course of study, it is observed that most of the potential hydropower sites have already been issued license or applied for license. Such areas have been marked on the topographic map and avoided in this study. This is also the reason of non availability of required number of sites for all the local bodies.

In province-1 there are 137 local bodies in total, out of which 87 number of hydropower sites of capacity between 500 to 1000KW in 56 local bodies have been identified at 65% dependable flow (Q65). Out of these 87 sites, there are more than one site in some local bodies however no hydro sites of given capacity have been found in 81 number of local bodies for which same capacity of solar/biomass project have been proposed for the development. The summary of all the identified hydro sites is attached in Annex-A. In case of those local bodies where more than one hydro site is identified, the best one for each local body is selected based on the following selection criteria:

- Lowest unit cost of energy,
- Higher value of B/C ratio,
- Higher value of IRR

These parameters mainly depend on the cost of transportation, cost of human resources, size of the hydropower, quantum of annual energy generation, and cost of transmission line and so on. Based on these facts, the cost of unit energy of the hydropower project located in the remote area seems to be higher and vice versa.

The cost for all the identified hydropower project has been computed based on the common assumptions. The rate analysis for different project is not computed separately. The rate for human resources and construction materials may be different for different district. Similarly the transportation charge of construction materials, electro mechanical and hydro-mechanical equipment may be different for different district project. The cost computed based on common assumption for different project at this phase of study cannot be considered as accurate as obtained from the rate analysis for individual project. However this cost estimate can be considered for planning of hydropower project development. The actual cost for each project, based on the approved norms of the Government of Nepal, needs to be computed during Feasibility study.

7.1.1.1 Detail Engineering stage.

The cost of energy per KW of the identified hydropower projects capacity of around 500 KW having low head, high discharge, long canal length and located in remote area has been found in higher side than that of the 1000KW capacity projects with high head.

7.1.1.2 Recommendations

- Field verification of all the identified hydropower sites needs to be carried out;
- Before the implementation of identified hydropower projects, Feasibility study and Detailed Engineering design for each projects needs to be carried out;
- The proposed design discharge and head for each site needs to be confirmed;
- Site specific hydrological, meteorological and sediment data collection and analysis is mandatory ;
- In this phase of study, Geological and seismological studies are missing, which needs to be carried out and confirmed before the implementation;
- Feasibility study needs to be linked with the basin optimization concept in holistic approach;
- Water right issues for all the hydropower sites needs to be confirmed and addressed before the implementation;
- In some projects intake site lies in one province/local body and powerhouse site falls in another local body/province, in such case interaction among such provinces/local bodies, needs to be carried out to develop trusty environment for the hydropower project development;
- Project cost and benefit needs to be confirmed during the feasibility and detail engineering study.

7.2 SOLAR

7.2.1 Solar PV With Battery

For the Base Case of 1 MWac Solar Plant with 500 kWh Battery Storage, the LCOE is quite high at NPR 11.96, 12.16, 12.56, 13.25, and 14.02 per kWh for Region E, F, D, C, A and B respectively. Highest LCOE is for Region B (East Hills) due to lowest CUF of 17.00% for this region and lowest LCOE is for Region E (Remote West Hills) followed by Region F (Very Remote West Hills). The high CUF of Regions E and F compensates for the higher Capital Costs of these regions (due to higher transport costs) to result in most cost effective solutions in these regions. Nonetheless, the Viability Gap Funding (VGF) required for each Region is high around NPR 100,000/kWac. Without VGF, the NEA PPA Rate with 8 no. of 3% escalations required for 15% ROE would be around NPR 14.85/ kWh. Further, if only 200 kWh of battery storage is considered for Region A, the Capital Costs will decrease to around NPR 140,000/kWac, which will result in lower VGF of NPR 83,000/kWac.

Sensitivity Analysis shows that if the Capital Costs decrease to NPR 120,000/ kWacwithin 5 years, the LCOE for Region A (East Terai) will decrease from NPR 14.02 to 10.25 per kWh with ROE of 1.60%, which will require lesser Viability Gap Funding (VGF) of NPR 61,000 per kW. If the Capital Costs of Solar PV with 500 kWh Battery Storage decrease to the range of NPR 60,000 per kWac within 5 to 10 years, the Plant will require no VGF as the LCOE will decrease to about NPR 5.18/ kWh and the LBOE of NPR 6.98/kWh (i.e. NEA PPA Rate of NPR 6/kWh with 8 no. of 3% escalations) will be enough to generate ROE of 18%. However, such drastic decrease in costs for Solar PV with Battery Storage is not possible immediately. Nonetheless, advancements in bi-directional inverter and battery technology could result in lower Capital Costs over time.

7.2.2 Solar PV Without Battery

For the Base Case of alternative Scenario in which 1 MWac Solar Plant without Battery Storage is considered, the LCOE of Region A (East Terai) decreases from NPR 14.02 to NPR 10.15 per kWh. Nonetheless, the Viability Gap Funding (VGF) of NPR 60,000/kWac is still necessary for ensuring 15% ROE. Without VGF, the NEA PPA Rate with 8 no. of 3% escalations required for 15% ROE would be around NPR 10.79/ kWh.

Sensitivity Analysis shows that if the Capital Costs of Solar PV without any battery decreases to NPR 100,000/ kWac within a few years, the LCOE for Region A will decrease from NPR 10.15 to 8.44 per kWh with ROE of 5.23%, which will require lesser Viability Gap Funding (VGF) of NPR 36,000 per kW. If the Capital Costs of Solar PV without Battery Storage decrease to the range of NPR 60,000 per kWac within 5 years, the Plant will require no VGF as the LCOE will decrease to about NPR 5.06/ kWh and the LBOE of NPR 6.98/kWh (i.e. NEA PPA Rate of NPR 6/kWh with 8 no. of 3% escalations) will be enough to generate ROE of 18%. However, such drastic decrease in costs for Solar PV is not possible immediately. Apart from the decrease in costs in the international market, the Capital Cost can be decreased through substantial policy interventions such as additional exemptions on tax, custom duty and excise duty.

Nonetheless, within the scope of this study, it would be unfair to compare Solar PV without any battery storage to Hydropower and Biomass technologies, as the Solar PV would not be able to supply any electricity during nights in the event the central grid is down, thus compromising on the aspect of reliability of supply. Nonetheless, Solar PV with Battery could be developed in two phases, such that Solar PV Plant without Battery but with adequate space for adding batteries and inverters later is developed in the first phase, and additional Inverter and Battery necessary is added in the subsequent phases. This will help to break the Total Investments and VGF into multiple phases while providing the flexibility of achieving increasing level of reliability from the project over time.

7.3 ECONOMIC AND FINANCIAL

7.3.1 Economic

For Province 1, the Net Present Value (NPV) is highest for Scenario A: Grid Extension with DG at NPR 736 billion. Scenario B: Grid Extension without DG yields lower NPV of NPR 671 billion. Similarly, both Scenarios have similar Economic Internal Rate of Return (EIRR) of approximately 39% and Pay Back Period (PBP) of approx. 2.5 years. As Economic evaluation considers the NPV while ranking projects, i.e. the net value added to the economy, Grid Extension with DG is recommended for Province 1. Sensitivity Analysis at higher SDR of 5% (Case I) shows that that NPV decreases to NPR 642 billion for Scenario A and to NPR 456 billion for Scenario B; nonetheless, the net economic value added is still higher for Scenario A. Similarly, Sensitivity Analysis at highest SDR of 8% (Case II) shows that that NPV decreases to NPR 352 billion for Scenario A and to NPR 321 billion for Scenario B; nonetheless, the net economic value added is still higher for Scenario A. Also, preliminary analysis shows that the results of economic analysis for Provinces 3, 4, 5, 6 & 7 would be similar to that of Province 1 (due to similar load and generation profile).

For Province 2, the NPV is highest for Scenario A: Grid Extension with DG at NPR 940 billion. Scenario B: Grid Extension without DG yields lower NPV of NPR 861 billion. Similarly, both Scenarios have similar EIRR of approximately 43% and Pay Back Period (PBP) of approx. 2.3 years. As Economic evaluation considers the NPV while ranking projects, i.e. the net value added to the economy, Grid Extension with DG is recommended for Province 2 as well. Sensitivity Analysis at higher SDR of 5% (Case I) shows that that NPV decreases to NPR 643 billion for Scenario A and to NPR 589 billion for Scenario B; nonetheless, the net economic value added is still higher for Scenario A. Similarly, Sensitivity Analysis at highest SDR of 8% (Case II) shows that that NPV decreases to NPR 455 billion for Scenario A and to NPR 418 billion for Scenario B; nonetheless, the net economic value added is still higher for Scenario A.

Therefore, in the context of the implementation of the new federal structure of Nepal, Grid Extension WITH DG can deliver high economic benefits along with equitable VGF to Municipalities for enabling universal energy access. Therefore, it is recommended to move forward with the Grid Extension WITH DG scenario and conduct further studies to accurately quantify the economic benefits of DG development with Grid Extension.

7.3.2 Financial

7.3.2.1 Province 1

In Province 1, 54 Hydropower sites with total installed capacity of 43 MW (which was the highest number of Hydropower sites selected in a Province), 71 Solar PV sites with total installed capacity of 71 MW, 11 Biomass sites with total installed capacity of 3.5 MW and 1 Wind power site with total installed capacity of 0.2 MW were selected. On average, the Investment required per kW for Hydro was NPR 319,347/ kW, for Solar was NPR 164,963/kW, for Biomass was NPR 300,000/kW and for Wind was NPR 198,250/kW. On average, the VGF required per kW for Hydropower was NPR 106,838/kW, for Solar was NPR 111,394/kW and for Wind was NPR 60,000/kW.

7.3.2.2 Province 2

In Province 2, no hydropower sites were found. 127 Solar PV sites with total installed capacity of 127 MW (which was the highest number of Solar sites selected in a Province), and 9 Biomass sites with total installed capacity of 3 MW were selected. On average, the Investment required per kW for Solar was NPR 164,661/kW, and for Biomass was NPR 300,000/kW. On average, the VGF required per kW for Solar was NPR 110,000/kW. The highest number and installed capacity of Solar PV sites in the country were selected in Province 2 due to absence of any Hydropower sites.

7.3.2.3 Province 3

In Province 3, 33 Hydropower sites with total installed capacity of 26.4 MW, 70 Solar PV sites with total installed capacity of 70 MW, and 16 Biomass sites with total installed capacity of 8.7 MW were selected. On average, the Investment required per kW for Hydro was NPR 336,219/ kW, for Solar was NPR 165,135/kW, and for Biomass was NPR 300,000/kW. On average, the VGF required per kW for Hydropower was NPR 131,032/kW, and for Solar was NPR 112,186/kW. The highest number of Biomass project sites in the country were selected in Province 3.

7.3.2.4 Province 4

In Province 4, 25 Hydropower sites with total installed capacity of 22.4 MW, 58 Solar PV sites with total installed capacity of 58 MW, and 2 Biomass sites with total installed capacity of 1.5 MW were selected. On average, the Investment required per kW for Hydro was NPR 248,127/ kW, which was the lowest in the country for Hydropower, for Solar was NPR 165,268/kW, and for Biomass was NPR 300,000/kW. On average, the VGF required per kW for Hydropower was NPR 44,036/kW, which was the lowest in the country for Hydropower, and for Solar was NPR 107,414/kW.

7.3.2.5 *Province 5*

In Province 5, 16 Hydropower sites with total installed capacity of 12.6 MW, 85 Solar PV sites with total installed capacity of 85 MW, and 8 Biomass sites with total installed capacity of 2.3 MW were selected. On average, the Investment required per kW for Hydro was NPR 375,604/ kW, which was the highest in the country for Hydropower, for Solar was NPR 164,945/kW, and for Biomass was NPR 300,000/kW. On average, the VGF required per kW for Hydropower was NPR 174,074/kW, which was the highest in the country for Hydropower, and for Solar was NPR 104,659/kW. The second highest number of Solar sites and second lowest number of Hydropower sites in the country were selected in Province 5.

7.3.2.6 *Province 6*

In Province 6, 45 Hydropower sites with total installed capacity of 43.1 MW, 33 Solar PV sites with total installed capacity of 33 MW, and 1 Biomass sites with total installed capacity of 0.3 MW were selected. On average, the Investment required per kW for Hydro was NPR 366,889/ kW, for Solar was NPR 167,044/kW, and for Biomass was NPR 300,000/kW. On average, the VGF required per kW for Hydropower was NPR 173,985/kW, and for Solar was NPR 99,727/kW which was the lowest in the country for Solar.

7.3.2.7 *Province 7*

In Province 7, based of Financial Analysis of identified projects, 48 Hydropower sites with total installed capacity of 44.9 MW, which was the highest installed capacity for Hydropower selected in a Province, 37 Solar PV sites with total installed capacity of 37 MW, and 3 Biomass sites with total installed capacity of 1.1 MW were selected. On average, the Investment required per kW for Hydro was NPR 306,787/ kW, for Solar was NPR 165,575/kW, and for Biomass was NPR 300,000/kW. On average, the VGF required per kW for Hydropower was NPR 93,216/kW, and for Solar was NPR 102,216/kW.

7.3.2.8 *Overall Nepal*

Overall 221 Hydropower sites with total installed capacity of 192.6 MW, 481 Solar PV projects with total installed capacity of 481 MW, 50 Biomass sites with total installed capacity of 20.4 MW and 1 Wind power site with installed capacity of 0.2 MW were selected.. The Total Investment required for Hydropower was NPR 62.54 billion, for Solar was NPR 79.42 billion, and for Biomass was NPR 6.12 billion, and for Wind was NPR 40 million; thus, the Total Investment necessary for whole country was NPR 148.13 billion. The Total VGF required for Hydropower was NPR 22.9 billion, and for Solar was NPR 51.9 billion, for Wind was NPR 12 million; thus, the

Total VGF necessary for whole country was NPR 74.88 billion. On average, the Investment required per kW for Hydro was NPR 324,772/ kW, for Solar was NPR 165,132/kW, and for Biomass was NPR 300,000/kW. On average, the VGF required per kW for Hydropower was NPR 119,110/kW, and for Solar was NPR 107,965/kW. However, due to limitations on federal budget, the recommended VGF has been discussed in the next sub-section (Implementation Modality) of this Chapter.

7.3.2.9 Two Alternative Cases – Solar PV with 200 kWh OR no battery storage

For the Alternative Cases, the Total Country Investment decreases significantly from NPR 148 Billion for Base Case of Solar PV with 500 kWh battery to NPR 138 Billion and NPR 126 Billion for Alternative Scenarios of Solar PV with 200 kWh battery and NO battery storage respectively. Similarly, the Total Viability Gap Funding (VGF) decreases significantly from NPR 74 Billion for Base Case of Solar PV with 500 kWh battery to NPR 63 Billion and NPR 51 Billion for Alternative Scenarios of Solar PV with 200 kWh battery and NO battery storage respectively. On average, the Investment required per kW for Solar with 200 kWh battery was approx. NPR 145,000 and for Solar with NO battery storage was approx. NPR 120,000. On average, the VGF required per kW for Solar with 200 kWh was approx. NPR 85,000 and for Solar with NO battery storage was approx. NPR 60,000. Nonetheless, these scenarios with less or no battery storage would comprise on the aspect of electricity reliability in case the central grid is down during the evening or nights.

7.4 IMPLEMENTATION MODALITY

There are few underlying concepts in the proposed solution, namely, investment in distributed generation projects in all municipalities as a means of increasing local economic growth in one side, and expansion of national grid through sub-transmission and distribution lines to all of the municipalities in the other. The underlying concepts include improving local capability in institutional management and distributing VGF for equitable development. The implementation modality needs to address all these four underlying concepts.

7.4.1 The two technical sides of the Concept for Implementation

The fundamental concept of Bi-directional planning and implementation for Sustainable Distributed Generation and Grid Access to All (SUDIGGA) is to work on both sides of the power system: at the local levels, locating a substation that best serves the local distribution network plan and constructing generation projects to feed the network and at the central grid side, constructing radial network expansion targeted and homing towards the substations at the local municipalities.

7.4.1.1 Distributed Generation projects

There are 221 Hydropower projects, 481 Solar PV projects and 50 Biomass to electricity projects, and 1 Wind power project recommended to be constructed. The generation projects development cycle necessarily contains following phases:

f) Feasibility Study and Detail Engineering Study

g) Financing of the project construction and concluding operational issues such as power sale

h) Formation of implementing agencies for local ownership of the generation projects, government agency for assisting the local governments to set-up the local vehicles, oversee the engineering of the projects and facilitate the equity, debt and VGF financing

i) Contract management, construction management, and generation upon commissioning

j) Operationalization of the plant operation agency and expansion of Low voltage distribution network to consumers

7.4.1.2 Expansion of Grid – Sub-transmission and distribution line and substation projects

There are 196 km of 132 kV sub-transmission lines, 8 number of 132/33 kV substation with 188MVA of transformer capacity, 5568 kms of 33 kV distribution lines, 323 Nos of 33/11 kV substations and 2063 kms of 11 kV lines with 199 Nos of 11kV switching stations for interconnection of generation projects and distribution feeders. These grid expansion projects require step-wise implementation.

Stepwise Expansion

Stepwise implementation is necessitated by the sequential nature of the expansion works as well as the need of temporally distributing the huge costs of expansion. The network expansion will start from the existing and under-construction substations of Nepal Electricity Authority. The outward expansion in first stage will consist of sub-transmission lines and 33 kV lines with substations at the end of the radial lines. The phasing may be in three or more stages. The costs of different stages of phased expansion is given in table below with details of the substation and Lines.

Table 38: Implementation Activities

Phase	Duration (yrs.)	No. of 132/33 kV Substations	No. of 33/11 Substations	No. of 11 kV switching stations	Length of 132 kV line	Length of 33 kV line	Length of 11 kV line	Estimated Cost (NPR in Million)
1	2.5	5	79	20	100	1540	270	14156.17
2	1(+1.5 overlap)	3	145	79	96.2	1895	843	22320.53
3	1(+2.5 overlap)	0	99	100	0	2133.4	950.9	17326,2
Total	**4.5**	**8**	**323**	**199**	**196.2**	**5568.4**	**2063.9**	**53.8 billion**

Time-line

The time-duration for the phased expansion alternatives are given in table above. The timetable covers the different activities required in implementing the expansion work, the detail of the activities are as given below.

f) Feasibility survey of the lines and substations, and detail design including tender document preparation

g) Financing of the expansion project – national budget and investment planning and allocation for the expansion works.

h) Facilitation with the implementing agency Nepal Electricity Authority or its Distribution agencies in the respective provinces in cooperation with the local municipality for eventual modality of operation of distribution network.

i) Contract management and construction supervision by NEA and the operating agency at the level of local municipality

j) Operationalization of the entity responsible for substation and distribution and expansion of Low voltage distribution network to consumers

The sequence of programs as listed above will be rolled out and put in place for each phase of the expansion project. The total time-plan for the above five activities for beginning of first phase to the end of the third phase will be within the five year timeframe as follows:

Table 39: Project Implementation Activities and Timeline

Activity	Description of Work	Remarks
1	Project Verification	Within 12 Months
2	Feasibility and Detail Study	Within 18 Months
3	Financial Arrangement	Within 30 Months
4	Project Construction	Within 54 Months
5	Grid Extension	Within 54 Months
6	Project in Operation	Within 60 Months

<u>Medium voltage transformer stations and Low Voltage distribution Network Expansion</u>

The SDG7 and SE4ALL accomplishment includes the last mile connection to the consumer houselholds. This study does not cover the last mile planning, as it is vast scope of work and such planning and investment decisions are best left to the Local Government bodies. However, it has to be noted here that in order to accomplish the Energy Access for All , planning for the last mile connection, and its financing must begin immediately after the launch of the first phase of the Grid Expansion, such that there is a seamless connection to the households and supply of electricity at the completion of the Five Year project.

It is understood that Nepal Electricity Authority is undertaking a Distribution Materplan that includes the Medium Voltage transformer stations, their capacity and aggregated nodes of the low voltage lines. It is also understood that the above Master Plan does not include detail GIS based distribution nework planning. It is therefore necessary that next phase of implementation should include GIS mapping of the Medium Voltage transformers and planning of Low Voltage network that is optimized with updated GIS data of population and load demand.

Monitoring of Operation and Maintenance and support system

The operation and maintenance of 11 kV switching substation and feeder lines as well as 33 kV substation and distribution lines can be done by local level agencies as the technology and know-how required is easily available and man-power can be trained. The cost of operation and monitoring increases with the location of the agency being farther from the area. The cost of logistics and additional costs incurred for man-power migration makes such operation not viable for these agencies. Hence, a local entity is preferred.

However, for large events, such as damage to 33kV transformer or circuit breaker or substation control and protection systems, the local entity will require external support. This will be more prominent in remote areas. For this reason, a regional or provincial support cell or entity need to be established to provide such operational support.

7.4.2 The Governance aspects of the Concept for Implementation

The SUDGGAA is feasible only with a meaningful participation from the local government bodies which will ensure sustainability of the project. The Constitution of Nepal 2072 mandates three levels of governance with definite rights and duties of the local bodies, which are empowered to legislate on subjects as listed in the Schedules of the Constitution. The Schedule 6 lists electricity distribution as the jurisdiction of Provincial government while the Schedule 8 lists the renewable generation projects as the jurisdiction of Local government. In recognition of the constitutional mandates, the Implementation Plan will need to enlist support and participation of the respective governments in formulating the projects as well as forming the entities responsible for implementing and operating them.

7.4.3 Agency for the Distributed generation projects

The Distributed generation projects are proposed as joint investment projects, with federal support as grant money for funding the viability gap while the local municipalities and cooperatives and directly Project affected people are supposed to invest the main equity. The capital required for constructing a generation project will be large ranging from NPR 16 Crores (USD 1 million) to NPR 30 Crores (USD 3 million), it is a natural proposition that a separate company shall be formed where the financing requirement after Viability Gap Fund is provided with equity injection (20-30%) from municipality, cooperatives and project affected people, and the remaining 70 to 80% of the finance requirement is secured from low-interest development loans from multi-lateral institutions or the government or by priority sector lending from national finance institutions.

e) Independent Generation Company – An independent public limited company is best suited to run the generation project and associated assets. The generation company may be wholly owned by the local municipality. It may also have alternative equity holding shared with local project-affected community or their cooperatives. This contributes towards more consolidated Sustainability of the generation project with shared and aligned interests of the very localized community.

f) Central utility holding - In the cases of remote municipalities, the operation of the distribution network and providing service to the consumer from an entity based in province capital city has proven to be financially unviable and burdensome for the central utility. In such cases, the central utility is inclined to lease the operation of the network to community electrification users groups (CEUG). There are mixed experiences with CEUG networks over time. Reduction in non-technical losses have been recorded, but reliability and quality of service has not improved.

g) Municipality managed utility ownership – Local ownership may reduce operational costs but a municipality owned and operated utility will be a microcosm of a government withutility at the center, which has been shown to be ineffective and consequently expensive, and hence, disowned by government at central level previously. It is therefore not recommended to keep such generation and distribution assets directly under the municipality.

h) Local Utility Company with combined generation and distribution assets – Presently, the Electricity Act requires that generation, transmission and distribution companies should be separate entities with separate licenses. At the local level, such demarcation is not essential as long as the transmission network is separated. The local generation project withViability Gap Fundingto utilize locally availableenergy resources is expected to lower the cost of local electricity. A joint utility will be also able to compensate for the high cost of providing distribution services.

From stakeholders' workshops and discussions with experts, it has emerged that the best format for Ownership of the generation project and consequent development, and operation is a Separate Public Company (Special Purpose Vehicle SPV). The shareholding of such a SPV is recommended to be evenly distributed amongst the municipality to provide the financial strength in case of shortfalls, and cooperatives of the project area and cooperatives of the electricity users and community user groups. Single group ownership still can not be relied upon to function effectively.

Since the generation project requires grant in terms of viability gap fund, the ownership of the SPV needs to have a broad public ownership and ensure that no private individual or business is owning disproportionately.

7.4.4 Agency for the distribution network

c) Central Utility holding – the construction of the line and substations are proposed to be completed in a condensed and intensive program within 5 years. Such program can be successful only if implemented by the central Utility having sufficient technical and organizational capability which is NEA in the present context. However, eventual ownership transfer or leasing to local utility is possible.

d) For town municipalities, the central and provincial utilities are inclined to maintain their ownership and they may also be well equipped to do so. Nonetheless, there could be other alternatives because the electricity supply business is undergoing rapid change. Even in South Asia, there are examples where wire and services are separated. In such a case, the wires can be owned by any of the models of a private or public company or a municipality-owned company.

From stakeholders' workshops and discussions with experts, it has emerged that the best format for Ownership of the Distribution Network is the SPV that owns the generation company itself, as the financial benefit of the generation project will balance the costs of distribution and maintaining the feeder from the grid. The generation company will be induced to maintain the connecting line to grid as the surplus energy supplied to grid provides the financial surplus to it.

Since the distribution network needs a separate licence and there are issues of overlap with the Central Utility or its subsidiary, the Initial phase of distribution network from the Grid till the local substation need to be with the Central Utility that constructs and completes the Grid Expansion. This is further so if the connecting line supplies power to more of the municipalities and hence, a SPV ownership will raise the issue of wheeling charges.

In remote areas, the cost of maintaining and operating these interconnecting lines will be uneconomically high for central and provincial utility. Thus, a phased hand-over of the interconnecting lines to the SPV is foreseen with a framework of wheeling charge or management charge in place before that.

7.4.5 Financing of the SUDIGGAA

A major component of the SUDIGGA project is the Viability Gap Funding (VGF) to be provided by federal government. Substantial VGF is required for generation projects while the wires have to be fully funded by the federal government.

- It is assumed that providing a level field for economic growth to all of the municipalities in principle that will be accepted and be one of the priorities of future governments. Electricity is not only considered a basic necessity in modern times, but it is the essential input for industrial growth, employment and development. Providing VGF for generation projects that enables grid expansion to remote areas is a necessary step forward in this direction. However, it is assumed that equitable VGF distribution will be called for by all municipalities. Such VGF, if provided, may not be applicable for similar hydro-projects but may be more appropriate for alternatives that provide better electricity at lower prices. This is the principle that allows planning of solar projects in areas that are already electrified, and bio-mass projects from solid waste in towns where even solar projects are not feasible due to high land costs, customs duties, etc.
- Viability Gap Fund vs. Benchmark VGF – Identifying the best possible generation project and then determining the viability gap fund is complex and tends to be convoluted. A mechanism to incentivize local body to find the best project is to set a benchmark VGF, and allow the municipalities to find the best project within the limits of the benchmark VGF. Viability gap fund helps to find the equitable proportion of VGF for remote and less-endowed municipalities. The lack of sufficient experience and culture of in such viability gap determination, and the need to undertake this exercise in all 753 units in a short period calls for a simplified VGF program. A benchmark VGF policy is therefore recommended.

7.4.6 VGF for generation-projects and financial viability

The hydro-projects have been selected with design discharge of 65% probability of exceedance. Projects with such design have plant factor of approximately 65% (at the grid connection point after accounting for all losses). The economic value of the energy in an already electrified area is the 'Willingness to Pay' of the consumers. A survey done by MCC, which is yet to conclude the results, is known to have received a preliminary estimate of 27% more than the current price. This same price may be used for determining the economic viability of a project and a criterion for justifying the VGF.The financial viability of the project after VGF is necessary for sustainable operation of the project. Hence, a favorable debt/ equity ratio is proposed for independent stock company such that the local municipality is required to put up minimum of equity fund.

For a 1000 kW hydro-project, the median cost of construction of a hydro-project is approximately USD 3500/ kW and generating approximately 6 million units in a year. A benchmark VGF of USD 1000/ kW will require about USD 2.5 million capital in 4 to 5 years from the local government. A debt/equity ratio of 80/20 will ease the capital requirement from the local municipality to USD 500,000 (approximately NPR 5 Crore) in 4 to 5 years, which is an outlay of USD 100,000 (approx.NPR 1 Crore) per year.

This projection is assumed to be feasible for all of the municipalities. A comparison with present Independent Power Producer (IPP) projects gives projects that have median construction costs of 2000 $/ kw for Q40 (having 5 million units a year) design discharges. Extrapolating the costs for Q65 (6 million units a year) and with a better wet-energy to dry-energy ratio, the financially viable cost of such projects lie around 2500$/kW.

However, for remote areas which are far from the roadhead, the remoteness factor has to be accounted. A remoteness factor of 1.2 is considered for higher cost of transportation of construction materials and in some heavy single transport cases, heli-lifting. Thus, projects of 4500$/kW are also selected for construction in such remote areas. Nonetheless, it is proposed that a benchmark VGF of 1000$ / kW or NPR 10 crore per MW be considered for accomplishing SUDIGGAA. For projects that have high transport costs, alternative solar or biomass projects could be considered, or they could be accomplished after appropriate road access is enabled.

From the discussions in the workshops, it has emerged that the benchmark subsidy or viability gap funding should be categorized to few varying VGF slabs taking into account the fact that some of the projects may not require much VGF while some of the remote areas would need a higher amount of VGF. Since the transaction analysis for a detailed work-out f VGF is complex and costs may outweigh the benefits of such exact VGF determination, it is recommended that based on Remoteness factor, three slabs of VGF be proposed, with VGF benchmark of less than 1000$/ kw for projects having road access, and 1000$ / kw for projects that are moderately far from the road-head and 2000$/kW for projects that are at least one-days travel from nearest road-head.

The Levelized Cost of Energy (LCOE) from Solar projects with 500 kWh Battery backup is quite high (NPR 12 to 14per kWh) at present costs of Battery and additional Inverter. For financial viability, VGF in the range of USD 1000 to 1100 is required out of the total Capital Cost of USD 1600 -1700/ kW. Even for Solar Project without any Battery Backup, LCOE of 1 MWac Solar PV Project is too high (NPR 9 to 10/ kWh); therefore, either NEA PPA Rate of around NPR 10/ kWh (with 8 simple escalations of 3% each) or Federal VGF of around USD 600/kW is necessary. Large part of the high cost is contributed by the price of land, and low capacity utilization factor (CUF) of solar. Nonetheless, it would be unfair to compare Solar PV without any battery storage to Hydropower and Biomass technologies, as the Solar PV would not be able to supply any electricity during nights in the event the central grid is down, thus compromising on the aspect of reliability of supply. A middle ground could be to develop Solar PV with Battery in two phases, such that Solar PV without Battery but with adequate space for adding batteries and inverters later is developed in the first phase, and additional Inverter and Battery necessary is added in the subsequent phases. This will help to break the Total Investments and VGF into multiple phases while providing the flexibility of achieving increasing level of reliability from the project over time. Since a benchmark VGF with three slabs is considered for hydro, same structure of VGF (i.e. USD 1000/ kW) is proposed for Solar PV plant with 500/ 200 kWh battery storage.

In the case of Biomass, high plant load factor, income from sale of electricity to NEA and additional income from sale of fertilizer byproduct results in a very attractive ROE such that no VGF is required. Nonetheless, due to scarcity of well-established waste collection system, and pilot projects for testing business models; the benchmark VGF of USD 1000/kW will also be appropriate for 50 selected Biomass Plants. For one selected 200kW Wind power plant with high wind resources available locally, the VGF required is about USD 600/ kW.

8 STUDY TEAM

Table 40: Study team of the project

S.N.	Name	Particulars	Area of Expertise	Experience
1	Hitendra Dev Shakya	Team Coordinator	Electrical Engineering	More than 20 Years in Hydropower Sector
2	Deepak Das Tamrakar	Team Leader of Assignment	Civil Engineering	More than 20 Years Experience in Hydro Sector
3	Om Krishna Shrestha	Group Leader	Electrical Engineering	More than 20 Years Experience in Hydro Sector
4	Gopal Basnet	Sub-group Province Leader	Civil Engineering	More than 20 Years in Hydropower Sector
5	Kalidas Neupane	Biomass Group Leader	Civil Engineering	More than 20 Years in Renewable Energy (Hydro and Biomass) Sector
6	Bhaskar Kafle	Sub-group P-3 Leader	Civil Engineering	More than 20 Years in Hydropower Sector
7	Sitaram Neupane	Sub-group P-4 Leader	Civil Engineering	More than 20 Years in Hydropower Sector
8	Khimananda Kandel	Group Leader - Hydropower	Civil Engineering	More than 15 Years in Hydropower Sector
9	Netra Timilasina	Sub-group P-5 Leader	Civil Engineering	More than 15 Years in Hydropower Sector
10	Baburaja Maharjan	Group Leader (Electrical)	Electrical Engineering	More than 10 Years Experience
11	Prajwal Khadka	Group Leader (Electrical)	Electrical Engineering	More than 10 Years Experience
12	Jiwan Kumar Mallik	Group Leader - Solar	Electrical Engineering	More than 10 Years of Experience in RE Sector

13	Abhishek Yadav	Economic Specialist and Solar Group Leader	Electrical Engineering and Energy Economics	More than 10 Years of Experience in RE Sector
14	Dipesh Shrestha	Group Leader (Solar)	Solar Expert	More than 10 Years of Experience in RE Sector
15	Niraj Karmacharya	GIS Expert	Geomatics Engineering	More than 5 Years Experience in GIS works
16	Prabhakar Khanal	Engineer-Geomatics	Geomatics Engineering	5 Years Experience in GIS works
17	Saurav Suman	Engineer – Hydropower	Civil Engineering	2-5 Years Experience in Hydropower Sector
18	Yuba Raj Acharya	Engineer – Hydropower	Civil Engineering	2-5 Years Experience in Hydropower Sector
19	Raju Mandal	Engineer – Hydropower	Civil Engineering	2-5 Years Experience in Hydropower Sector
20	Binod Karki	Engineer – Hydropower	Civil Engineering	2-5 Years Experience in Hydropower Sector
21	Neeraj Kumar	Engineer – Hydropower	Civil Engineering	2-5 Years Experience in Hydropower Sector
22	Nabin Panta	Engineer – Hydropower	Civil Engineering	2-5 Years Experience in Hydropower Sector
23	Binay Paudyal	Engineer - Power System	Electrical Engineering	More than 1 Year Experience
24	Kishor Karki	Engineer – Electrical	Electrical Engineering	More than 1 Year Experience
25	Bishnu Dawadi	Engineer – Electrical	Electrical Engineering	More than 1 Year Experience
26	Tika Ram Regmi	Engineer – Electrical	Electrical Engineering	More than 1 Year Experience

27	Ravi Raj Shrestha	Engineer – Electrical	Electrical Engineering	More than 1 Year Experience
28	Prasan Lama	Engineer-Geomatics	Geomatics Engineering	1 Year Experience in GIS Works
29	SurajUpadhyay	Engineer-Geomatics	Geomatics Engineering	1 Year Experience in GIS Works
30	Amir Bhandari	Engineer-Geomatics	Geomatics Engineering	1 Year Experience in GIS Works
31	Shalik Ram Lamsal	Engineer-Inititate-Geomatics	Geomatics Engineering	Initiating in GIS Works
32	Ranju Pote	Engineer-Inititate-Geomatics	Geomatics Engineering	Initiating in GIS Works
33	Bijay Aryal	Engineer-Inititate-Geomatics	Geomatics Engineering	Initiating in GIS Works
34	Asutosh Bhandari	Engineer-Inititate-Geomatics	Geomatics Engineering	Initiating in GIS Works
35	Himal Chand	Engineer-Inititate-Geomatics	Geomatics Engineering	Initiating in GIS Works
36	Jagadish Poudel	Engineer-Inititate-Geomatics	Geomatics Engineering	Initiating in GIS Works
37	Ishwor Sapkota	Engineer-Inititate-Geomatics	Geomatics Engineering	Initiating in GIS Works
38	Yurosh Sapkota	Engineer-Inititate-	Geomatics Engineering	Initiating in GIS Works

		Geomatics		
39	Abin Prajapati	Engineer-Inititate-Geomatics	Geomatics Engineering	Initiating in GIS Works
40	Anushka Adhikari	Engineer – Electrical	Electronics and Communication Engineering	Initiating
41	Abanish Tiwari	Engineer–Initiate-Electrical	Electrical Engineering	Initiating
42	Bibhav Rayamajhi	Engineer – Initiate - Civil	Civil Engineering	Initiating
43	Ramesh Kandel	Engineer – Initiate - Civil	Civil Engineering	Initiating
44	Ashish Regmi	Engineer - Electrical	Electrical Engineering	Initiating

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10 ANNEXES

Annex A : Summary of Identified Hydropower Projects

Annex B : Summary of Identified Solar Power Projects

Annex C : Summary of Cost and Identified Sites of Biomass Power Projects

Annex D : Summary and Cost Estimate of Identified Grid Extension Network

Annex E : Summary Report of Identified Hydropower Projects

(District Wise Report Submitted)

Annex F : Cost Estimate for Solar Power Projects

Annex G : GIS Maps of Identified Biomass Power Projects

Annex H: GIS Maps of Identified Hydropower Projects

Annex H-1 : (GIS Map of Province No: 01, 03 and 04)

Annex H-2 : (GIS Map of Province No: 05, 06 and 07)

Annex I : GIS Maps of Identified Solar Power Projects

Annex J : GIS Maps of Identified Substations

Annex K: Parameters for Financial Analysis Model

Annex L : Parameters for Economic Analysis Model

Annex M: GIS Map of Identified Wind Power Projects

Annex N: Field Visit Findings

Annex O: Minutes from the Workshop