Modelling energy supply options for electricity generations in Tanzania

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Abstract

The current study applies an energy-system model to explore energy supply options in meeting Tanzania's electricity demands projection from 2010 to 2040. Three economic scenarios namely; business as usual (BAU), low economic consumption scenario (LEC) and high economic growth scenario (HEC) were developed for modelling purposes. Moreover, the study develops a dry weather scenario to explore how the country's electricity system would behave under dry weather conditions. The model results suggests: If projected final electricity demand increases as anticipated in BAU, LEC and HEC scenarios, the total installed capacity will expand at 9.05%, 8.46% and 9.8% respectively from the base value of 804.2MW. Correspondingly, the model results depict dominance of hydro, coal, natural gas and geothermal as least-cost energy supply options for electricity generation in all scenarios. The alternative dry weather scenario formulated to study electricity system behaviour under uncertain weather conditions suggested a shift of energy supply option to coal and natural gas (NG) dominance replacing hydro energy. The least cost optimization results further depict an insignificant contribution of renewable energy technologies in terms of solar thermal, wind and solar PV into the total generation shares. With that regard, the renewable energy penetration policy option (REPP), as an alternative scenario suggests the importance of policy options that favour renewable energy technologies inclusion in electricity generation. Sensitivity analysis on the discount rate to approximate the influence of discount rate on the future pattern of electricity generation capacity demonstrated that lower values favour wind and coal fired power plants, while higher values favour the NG technologies. Finally, the model-

ling results conclude the self-sufficiency of the country in generating future electricity using its own energy resources.

Keywords: electricity generation, MESSAGE model, discount rate, renewable energy, supply options

1. Introduction

Energy is an important element in accomplishing the interrelated socio-economic development of any country. Tanzania's energy supply relies mainly on biomass, which accounts for nearly 90% of the total primary energy supply (Wawa, 2012, IEA, 2013). The remaining energy supply is accounted from petroleum products at approximately 8%, grid electricity 1% and renewable energy sources such solar and wind which account for nearly 1% (MEM, 2012, Kabaka and Gwang'ombe, 2007). Total electricity generation shares in 2012 were mainly from natural gas 50.7%, hydro 28.6%, oil products 20.1%, biofuels 0.3% and solar PV 0.2% (IEA, 2014). Projections are approximating electricity demand to reach 47.7 TWh in the year 2035 equivalent to an annual growth of approximately 8% (MEM, 2012). Energy resources are enormous and are available in various forms, including biomass, hydro, geothermal, biogas, wind, solar, natural gas and coal (Kihwele *et al.*, 2012, MEM, 2013a). There is an estimated coal proven reserve of 304 million tonnes. whereas that of natural gas is 45 billion cubic meters (Kusekwa, 2013, MEM, 2012). Geothermal has an estimated potential of 650 MW (Mnjokava, 2008, Kihwele *et al.*, 2012), while

hydro estimated potential is 4700 MW (MEM, 2012). Biomass estimated sustainable potential is 12 million TOE from agriculture wastes, plantation forests and natural forests (Wilson, 2010). The country experiences annual sunshine hours of 2 800 to 3500 hours and solar irradiation ranging from 4-7 kWh/m^2 across the country (Casmiri, 2009, Kihwele *et al*., 2012). The renewable energy potential in the country is substantial but largely untapped for electricity and other thermal applications (Bauner *et al*., 2012, Kichonge *et al*., 2014b). The country's renewable energy potential from municipal solid wastes currently disposed in dump sites is considerable as shown in studies by Omari *et al*. (2014a) and Omari *et al*. (2014b).

Tanzanian energy demand, specifically electricity, has been growing over years because of socio-economic transformations that opened up the country's economy. Statistics on the country's GDP growth since the year 2000 show an annual average increase of 7% (BOT, 2012). However, substantial challenges faces the electricity sector owing to constrained generation capacity and distribution network (Kapinga, 2013, Wangwe *et al*., 2014) which previously resulted in outages and rationing (Loisulie, 2010, MEM, 2013b). Despite the electricity sector challenges, the demand is expected to grow as the country targets a middle income economy status as detailed in Development Vision 2025 (URT, 1999) and its implementation through Big Results Now (BRN) initiatives (Kahyoza, 2013). Realizing Tanzania Development Vision 2025 goals implies that the country needs adequate, reliable, affordable and environmentally friendly electricity supply options. Achieving these require optimal generation capacity additions, which consider diversifications of power plants systems. Finding optimal generation capacity addition based on least cost plan is important in formulating supply options considering the high investments costs associated with it. It is therefore the objective of this study to apply MESSAGE (Model for Alternative Energy Supply Strategies and their General Environmental Impacts) to find least-cost optimal energy supply options. MESSAGE is an appropriate framework for this study as it is capable of dealing with long-term planning horizons based on high-resolution short-term system dynamics. Using MESSAGE, optimization of electricity supply options in each scenario will help describes possible future final electricity supply options availability. Study results will benefit policy and decision makers to arrive at a relevant solution interactively in national electricity system expansion planning.

2. Methodology
2.1 MESSAGE Model
Model for Energy Supply Strategy Alternatives and their General Environmental Impacts (MESSAGE) is an optimization modelling tool (Messner and Strubegger, 1995), which calculates the least-cost energy supply system. Connolly *et al*. (2010), describes MESSAGE as a bottom-up model capable of optimizing operation and investment of technologies in medium to long term energy systems. MESSAGE modelling approach allows the realistic evaluation of the long-term role of an energy supply option under competitive conditions (IAEA, 2008, Hainoun *et al*., 2010). The least-cost determination in MESSAGE is through minimization of the total discounted energy system cost subject to the constraints representing demands, resource deficiency and capacity limits. Discounted energy system cost minimization includes investments, fixed and variable operation costs, maintenance costs, fuel and any additional penalty costs, which defines the limits and constraints relation. With MESSAGE, alternative energy supply strategies in agreement with user-defined constraints are assessed (IAEA, 2006, Tait *et al*., 2014).

Mathematical techniques tied up with MESSAGE comprises of linear and mixed-integer programming. The purpose for linear programming (LP) applications is that all the limits and the objective function (optimization target) are linear functions of the decision variables. Mixed-integer use in MESSAGE is due to integer values at the optimal solution requirements by some of the decision variables. Objective function in MESSAGE modelling approach is as shown in Equation 1. The variable $X_{i,j,t}$ denotes a flow variable (input) of fuel form *i* in technology *j* in the time step *t*. Flow variable describes amount produced in which technology and the type of fuel. The investment variable denoted by $Y_{i,t}$ represents new installation of technology *j* in time step *t*.

$$\text{Min} \sum \text{Cost} * \left(X_{i,j,t} + Y_{i,t} \right) \tag{1}$$

The MESSAGE model computes the objective function to satisfy the condition to ensure demand-supply balance as illustrated in equation 2. The parameter *D* denotes energy demand, *j* represents energy demand of *j* while *t* represents time step. In addition, η represents technology efficiency, *X* denotes production decision of the technology, *i* is the number of technologies and *n* total number of technologies.

$$\sum_{i=1}^{i=n} \eta_{i,t} X_{it} \geq D_{j,t} \tag{2}$$

MESSAGE has been used to model the power supply sector by means of the principle of reference energy system (RES), which allows representation of the entire energy network including possible development paths (Rečka, 2011, Selvakkumaran and Limmeechokchai, 2011). RES is composed of

energy resources and sources, energy carriers (form) and technologies. RES captures network flow of energy carrier from one process to the other starting in the resource to the consumer delivery. The explanation of energy forms includes each level of energy chains, technologies using or producing these energy forms, and the energy resources. MES-SAGE defines energy forms and technologies in all steps of energy chains. This includes identification of energy chain levels beginning from the demand to the resources, the energy forms to energy services. MESSAGE computes energy demand from the first level of each energy chain up to the energy resource level. Final demand level is distributed according to the types of consumption (Van Beeck, 1999, Pinthong and Wongsapai, 2009).

The MESSAGE modelling approach has previously applied to formulate an optimal energy supply strategy for Syria (Hainoun *et al.,* 2010); policy options study for power sector in Zambia (Tembo, 2012); strengthening of renewable energy applications (IAEA, 2007; IAEA, 2006); Optimal electricity system planning in a large hydro jurisdiction: Will British Columbia soon become a major importer of electricity? (Kiani *et al.,* 2013) alternate electricity supply model (Roque, 2014); climate change policy analysis (Nakicenovic *et al.*, 2000): nuclear energy in mitigating CO_2 emissions (AlFarra and Abu-Hijleh, 2012) among many others. Further information on MESSAGE as LP optimization tool is as found at the IAEA organization web site (www.iiasa.ac.at/web/home/research/modelsData/MESSAGE/MESSAGE.en.html).

2.2 Electricity demand projections
The final electricity demand projections were done using Model for Analysis of Energy Demand (MAED) (Kichonge *et al.,* 2014a) and have been summarized in Figure 1. MAED is a bottom-up modelling approach (Bhattacharyya and Timilsina, 2009) chosen because of its suitability to model the final electricity demand projections based on time and data availability. Suitability of MAED to relate systematically the corresponding social, technological and economic factors which affect the demand was also considered in the selection of the model (IAEA, 2006, IAEA, 2009). Literatures such as *Hainoun et al.* (2006), IAEA (2006)), IAEA (2009), Nakarmi *et al.* (2013) and the IAEA organization website (www-pub.iaea.org/MTCD/publications/PDF/CMS-18_web.pdf) gives detailed account of MAED.

2.3 Modelling framework
2.3.1 Electricity conversion technologies
Conversion technologies considered includes coal fired power plant, solar PV, hydro, solar thermal, biomass, conventional gas turbine (GT), heavy fuel oil (HFO) and combined cycle gas turbine (CCGT) power plants.

2.2.2 Reference energy system (RES)
The proposed Tanzanian RES accommodates resources, primary, secondary and final demand energy levels. Simplified schematic flow of the energy chains, levels and conversion technologies in RES are as described in Figure 1. Rectangles in the RES represent the technologies, which contain the techno-economic data. A single technology as used in the proposed RES denotes all conversion technologies, which uses the same type of fuel. The energy resource level is characterized by coal and
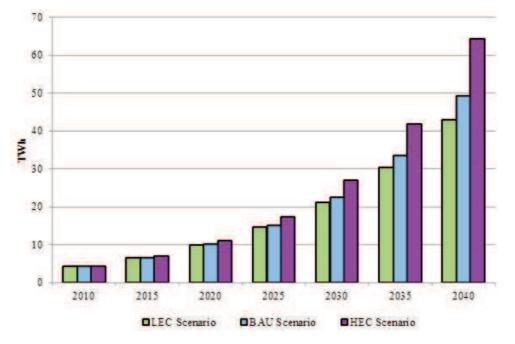

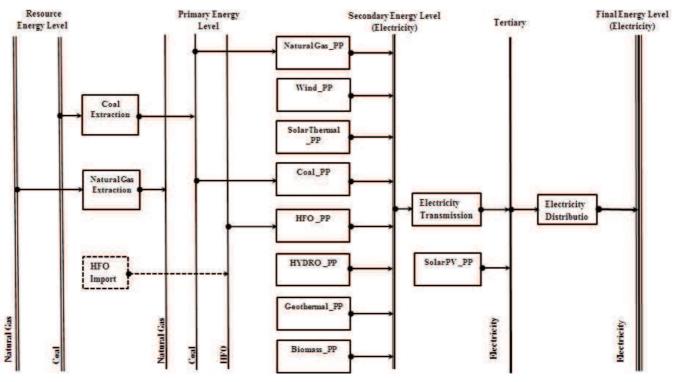**Figure 1: Electricity demands projections**

Figure 2: Energy chain levels and conversions technologies schematic flow diagram

natural gas, which are locally available resources. Energy carriers in the form of natural gas (NG), coal and HFO defines primary energy level in the energy chain. The secondary energy level is composed of electricity as the only form of energy echoed in this study. Intermediary of primary and secondary energy levels, there are electricity conversion technologies whose main inputs are energy carriers from the primary energy level. Electricity transmission and the distribution network connect secondary and final energy levels. The final electricity demand developed from the model's external factors (Kichonge *et al.,* 2014a) is given at the first level of each energy chain. The model calculates the equivalent productions of each of the technologies at the succeeding levels of the chain up to the energy resource level, which then gives the optimal technical choice by minimizing the total system cost, while meeting the given final electricity demand.

2.4 Modelling basic assumptions
The general assumptions considered in modelling energy supply options for electricity generation for Tanzania are as follows:

*   All model scenarios span from 2010, which is the base year to 2040 as the last year. A time step of five years has been adopted throughout the study period as more steps slows down the solver and also for easy results reporting;
*   Each model year in all scenarios is divided into four seasons to capture seasonal variations in reservoir inflows and load for hydro, solar PV and wind turbines. The seasons includes Season 1, which encompasses January to February (dry season); Season 2 – March to May (wet/rainy season); Season 3 – June to September (dry/sunny weather season) and Season 4 – October to December (short rainy season);
*   The expected load profile for defining the mix in power generation plants follows an annual hourly and monthly load curve characteristics as shown in Figures 3 and 4. An annual hourly load curve with characteristics was produced from hourly generation data collected for the years 2009 to 2012. Generation of annual hourly load curves was done by taking average values in load demands for a particular hour throughout a year. Daily base load patterns together with energy resources variations are taken into account by describing two types of days which are workdays (Monday to Saturday) and weekends (Sunday and holidays). The daily base load patterns for a 24 hour day has been divided as nine parts for Season 1, ten parts for Season 2, eight parts for Season 3 and twelve parts for Season 4;
*   Final electricity demand differences under business as usual (BAU), low economic consumption (LEC) and high economic growth (HEC) scenarios as projected in MAED are as depicted in Figure 1. Other parameters such as energy forms, seasonal and daily power demand variability, constraints, technologies and resources remained the same for BAU, LEC and HEC scenarios.
*   Air emissions control measures have not been included in the model;
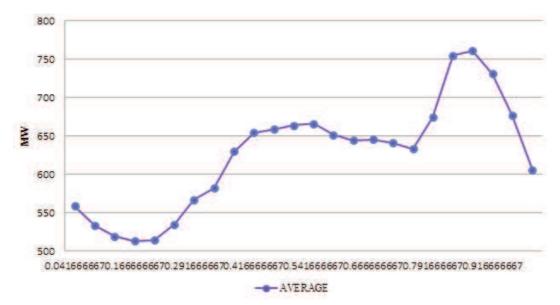*   The operation time thus electricity output for

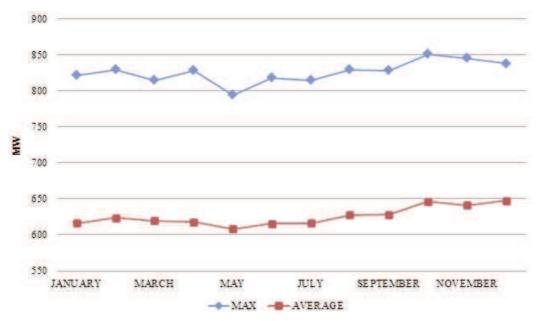**Figure 3: Annual hourly load curve characteristics**

Figure 4: Annual monthly load curve characteristics

solar PV, solar thermal and wind power plants follows the proposed seasonal and daily sunshine/wind variation;

- Geothermal power plants begin operation in 2025, with an initial installed capacity of 100 MW and increasingly to 650 MW in 2040 (MEM, 2012, Mnzava and Mayo, 2010);
- The discount rate parameter for economic evaluation of the future investment project was set to 10% in each scenario;
- The entire national electricity system has been simplified and modelled as a single grid system;
- Existing and future expansion projects, transmission and distribution losses and reserve margins as specified in the power system master plan (MEM, 2012) has been adopted for optimization

purposes;

- Summary of the crucial parameters for modelling electricity supply options in terms of specific technical and economic characteristics adopted for conversion technologies are as depicted in Table 1.
- The investment costs for renewable energy technologies (wind, solar PV and thermal) assumed a decreasing trend as the industry develops and thus becomes cost competitive in future (Philibert, 2014). The investment cost for wind technology in the base year as shown in Figure 5 was approximated at 2 438 US$/kW and then decreased steadily to 1 800 US$/kW in 2025 where it assumed this constant value to 2040. Solar PV technology investment costs assumed

Table 1: Summary of technical and economic characteristics of conversions technologies

	CCGT_PP	GT_PP	Hydro_PP	Solar PV_PP	*Conversion technology* Solar TH_PP	Biomass_PP	HFO_PP	Wind_PP	COAL_PP
Investment Costs (US$'00/kW)	1808.5	1220	2227	4000	4500	3860	800	2438	1900
Variable O & M Costs (US$'00/kWyr)	26.5	39.5	4.5	0	40	26.5	105	4.5	52.56
Fixed Costs (US$'00/kW/yr)	9.5	9.5	8.5	40	149	40	20	40	50
Plant life (years)	25	25	50	30	30	30	40	25	30
Plant factor (share)	0.95	0.95	0.95	0	-	0.95	0.75	0.9	0.95
Efficiency (%)	0.52	33		-	-	28	30	-	40
Operation time (share)	0.94	0.75	0.85	0.26	0.26	0.9	0.7	0.35	0.85
Input	NG	NG	-	-	-	Biomass	HFO	-	Coal
Output	Electricity	Electricity	Electricity	Electricity	Electricity	Electricity	Electricity	Electricity	Electricity

a base year value of 4 000 US$/kW and decreased in steps to 3 500 US$/kW and 2 500 US$/kW in 2025 and 2030 respectively where it presumed a constant value of 2 500 US$/kW towards the year 2040. Similarly, the investment cost for solar thermal technology towards the end of the study period presumed a decreasing trend from the base year value of 4 500 US$/kW to 3 500 US$/kW.

3. Results and discussions

Final electricity demands have been optimized in order to determine the optimal energy supply options for Tanzanian electricity sector. This section presents MESSAGE modelling results calculated based on the least-cost energy supply options for electricity generation for the period 2010-2040. Based on the total system costs of the electricity system discounted over the study period 2010-2040,

three different energy supply options have been optimized in lieu of BAU, LEC and HEC scenarios as detailed in Kichonge *et al.* (2014a).

3.1 Installed capacity

The total installed capacity increases gradually from 804.2 MW in the base year to 10 811.5 MW, 9 190.6 MW and 13 325.6 MW in 2040 for BAU, LEC and HEC scenarios respectively as illustrated in Figure 6. The least-cost optimal results show HEC scenario has the highest total capacity additions at 12 521.4 MW in 2040 as compared to the BAU scenario 10 007.3 MW and LEC scenario 8 386.65 MW. Annual increase of installed capacity in HEC scenario is equivalent to 9.81%, while BAU and LEC scenarios projection increases are 9.05% and 8.46% respectively. Hydro, NG, coal and geothermal power plants dominate the total installed capacity additions in all scenarios. Wind and bio-
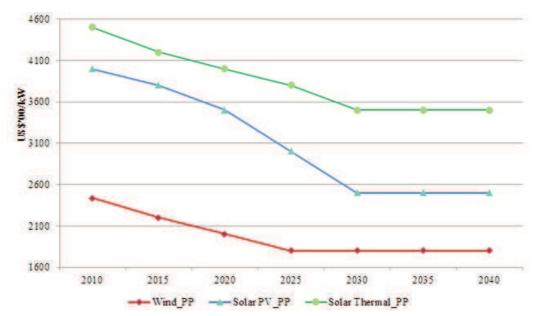

Figure 5: Evolution of the investment costs for wind, solar thermal and solar PV power plants

Table 2: Least cost installed capacity shares by technology (MW)

	2010	2015			2020			2025			2030			2035			2040		
	Base Year	BAU	LEC	HEC	BAU	LEC	HEC	BAU	LEC	HEC	BAU	LEC	HEC	BAU	LEC	HEC	BAU	LEC	HEC
Coal_PP	-	–	–	–	9.3	7.4	14.2	10.1	5.0	9.2	7.3	3.7	13.2	27.0	18.3	26.7	29.1	27.0	25.6
HFO_PP	5.1	10.8	10.9	10.5	6.4	6.6	6.1	4.34	4.48	3.95	3.16	3.31	2.75	2.37	2.61	1.92	0.96	1.13	0.78
CCGT_PP	–	30.6	30.2	33.2	36.8	37.6	34.8	24.8	27.9	31.6	9.8	11.1	12.9	2.4	5.2	15.9	18.4	16.7	31.8
GT_PP	25.1	21.9	22.0	21.1	13.8	13.8	12.8	9.1	9.4	8.3	6.8	5.6	7.7	7.8	7.3	6.5	5.2	6.1	4.2
Hydro_PP	69.8	35.4	35.6	34.1	25.4	25.9	24.0	43.3	44.6	39.3	56.4	59.1	49.0	51.0	56.0	41.3	35.8	42.1	29.0
Wind_PP	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	4.6	–	3.8
Biomass_PP	–	1.2	1.2	1.2	0.8	0.8	0.7	0.5	0.5	0.5	0.4	0.4	0.3	0.2	0.2	0.2	–	–	–
GeoTh_PP	–	–	–	–	–	–	–	2.6	2.7	2.4	12.4	12.9	10.7	9.3	10.2	7.5	6.0	7.1	4.9
Solar_PV	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Solar_Th	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Electricity Import	–	–	–	–	7.8	7.9	7.3	5.2	5.4	4.8	3.8	4.0	3.3	–	–	–	–	–	
Total(%)	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100

mass represents a small proportion in the total installed capacity whereas solar PV and thermal were not able to compete.

There is a corresponding increase of thermal installed capacity addition (coal and NG power plants) in both scenarios. NG power plants (CCGT and GT) increase their shares in the total installed capacity from 202 MW in 2010 to 2 546.55 MW in 2040 for BAU scenario. LEC scenario observes a similar increasing trend to 2 090.67 MW in 2040, while HEC scenario is 4794.47 MW. The shares of hydro power plants witnesses an opposite decreasing trend in the period 2015-2030, where it picks-up the dominance to 2035. Hydro power plants shares decrease from 69.8% in 2010 to 35.8%, 42.1% and 29% in 2040 for BAU, LEC and HEC scenarios respectively. The main reason attributed to the decreasing trend is the potential constraints despite the fact that it is the cheapest in operating costs (MEM, 2013b).

3.2 Least cost electricity generation mix
Summarized least cost total electricity generation for each scenario are as shown in Figure 7 and the least-cost electricity generation supply options results by technology in Table 3. BAU scenario least cost electricity generation expanded from 5 632 GWh in 2010 to 62 770 GWh in 2040. The expansion is equivalent to an annual growth rate of 8.4% as compared to 7.9% and 9.3% for the LEC and
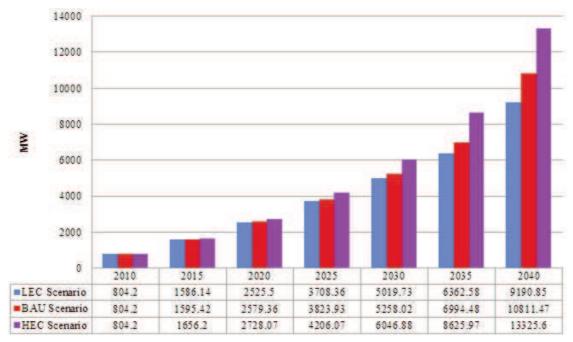

	2010	2015	2020	2025	2030	2035	2040
LEC Scenario	804.2	1586.14	2525.5	3708.36	5019.73	6362.58	9190.85
BAU Scenario	804.2	1595.42	2579.36	3823.93	5258.02	6994.48	10811.47
HEC Scenario	804.2	1656.2	2728.07	4206.07	6046.88	8625.97	13325.6

Figure 6: Least cost total installed capacity (2010-2040)

Table 3: Least cost electricity generation shares by technology

	2010	2015			2020			2025			2030			2035			2040		
	Base	BAU	LEC	HEC	BAU	LEC	HEC	BAU	LEC	HEC	BAU	LEC	HEC	BAU	LEC	HEC	BAU	LEC	HEC
Coal_PP	–	–	–	–	11.8	9.3	17.7	13.3	6.7	11.9	6.6	3.3	15.0	25.9	17.2	30.4	38.1	33.5	3.0
HFO_PP	2.0	0.2	0.2	0.2	–	–	–	0.03	0.02	0.06	0.05	0.03	0.04	0.03	0.03	0.02	0.01	0.01	0.01
NGpower plants	28.9	54.3	53.8	56.5	57.1	58.8	53.4	28.9	33.1	36.9	11.8	11.8	14.5	7.5	9.8	15.8	10.7	10.6	27.6
CCGT_PP	–	76.5	76.2	78.8	86.9	86.6	86.8	88.6	89.4	92.6	88.3	92.2	90.5	88.3	91.2	96.3	96.9	95.7	99.3
GT_PP	100.0	23.5	23.8	21.2	13.1	13.4	13.2	11.4	10.6	7.4	11.7	7.8	9.5	11.7	8.8	3.7	3.1	4.3	0.7
Hydro_PP	66.7	44.3	44.7	42.2	30.4	31.2	28.2	53.9	56.1	47.8	66.0	69.8	56.5	55.2	60.5	44.6	41.2	47.1	31.7
Wind_PP	–	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.2	0.0	1.7
Biomass_PP	2.5	1.2	1.2	1.0	0.6	0.6	0.6	0.3	0.3	0.2	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0
GeoTh_PP	–	–	–	–	–	–	–	3.6	3.8	3.2	15.2	14.8	13.8	11.2	12.3	9.1	7.7	8.8	5.9
Solar_PV	–	–	–	–	–	–	–	0.0	–	–	–	–	–	–	–	–	–	–	–
Solar_Th	–	–	–	–	–	–	–	0.0	–	–	–	–	–	–	–	–	–	–	–
Electricity Import	–	–	–	–	0.1	0.1	0.2	–	–	–	0.1	0.1	0.1	0.1	0.1	0.1	0.05	0.1	0.03
Total(%)	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100

HEC scenarios respectively. The base year proportions in the generation mix include hydro (66.7%), NG (28.9%), biomass (2.5%) and HFO (2%). Results describe general dominance of hydro power plants in the generation mix with NG, biomass and HFO power plants compensating the balance. The optimized results show the proportion of hydropower plants generation increasing gradually to 41.2 %, 47.1 % and 31.7 % in 2040 for BAU, LEC and HEC scenarios respectively.

The proportion of coal power plants in the total generation rises gradually from 11.8 % in 2020 to 38.1% in 2040 for BAU scenario while for LEC scenario is 9.3% in 2020 and rises to 33.5% in 2040. HEC scenario witness higher proportion at 17.7% in 2020 and grows to 33% in 2040. The higher proportion of hydro, NG and coal power plants in the generation mix is imminent due to lower investment and fuel costs as compared to other candidates technologies considered. Unlike the increases in
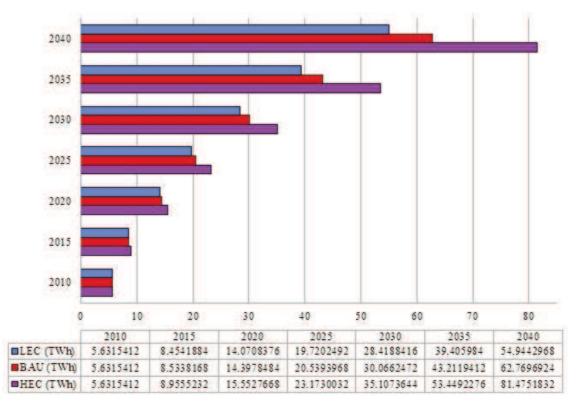

	2010	2015	2020	2025	2030	2035	2040
LEC (TWh)	5.6315412	8.4541884	14.0708376	19.7202492	28.4188416	39.405984	54.9442968
BAU (TWh)	5.6315412	8.5338168	14.3978484	20.5393968	30.0662472	43.2119412	62.7696924
HEC (TWh)	5.6315412	8.9555232	15.5527668	23.1730032	35.1073644	53.4492276	81.4751832

Figure 7: Least cost electricity generation for study period (2010-2040)

hydro and coal power plants generation shares, the proportions of NG power plants increasingly dominate more than 50% of the generation from 2015-2020 and thereafter declines in 2040. The decline in NG power plants proportions after 2020 is due to presumed new investments in hydro power plants. NG power plants technologies proportion in 2040 for BAU scenario split into CCGT (96.9%) and GT (3.1%). However, a similar trend follows in LEC and HEC scenarios in which the share of CCGT will be as high as 95.7% and 99.3% respectively in 2040. The choice of CCGT in least-cost optimized results attributes to higher availability and efficiency up to 60% in comparison to that of GT 40% (Sharman, 2005, Sims *et al.*, 2003). Combined thermal generation contributes 48.8% of the total in 2040 for BAU scenario whereas the contribution of thermal generation for LEC scenario is 44.1 % and that for HEC scenario is 60.6%. Higher final electricity demands in HEC scenario drives the increase in the use of thermal generations. Hydro and geothermal resource potential constraints attributes to the use of more thermal generations towards the end of the study period. On the contrary, renewable energy with the exclusion of hydro makes up small proportion in the contribution of the total electricity generation mix.

The contribution of renewables technologies into electricity generation for BAU, LEC and HEC scenarios extends to 6.2 TWh, 4.8 TWh and 6.2 GWh respectively in the year 2040. The share of renewable energy generation in BAU scenario accounted for an average of 2.1% in the period from 2010 to 2025 and, thereafter, grows to 15.4% in 2030 and then retreats to 9.9% in 2040. The rise of renewable energy in 2030 attributes to utilization of full geothermal energy potential presumed in the year. HEC scenario shares of renewable energy from 2025 – 2040 averaged at 1.9 % in the total electricity generation. Comparable trends are also as observed in LEC scenario. Moreover, within renewable energy technologies, geothermal dominates the generation mix followed by biomass and wind with insignificant shares from solar thermal and solar PV power plants. Geothermal and wind

power plants by the end of the study period in 2040 generated 7.7 % and 2.2 % respectively of all electricity in the BAU scenario. Similarly, geothermal power plants generation for LEC and HEC scenarios was approximately 8.8 % and 5.9 % respectively. The constraints on geothermal energy resources potential and the rise in electricity demand reduced the share of geothermal technologies in 2040 for HEC scenario.

The least-cost electricity generation results in the BAU, LEC and HEC scenarios draws four most important conclusions. The first one is the key role played by hydro, coal and NG technologies in the final electricity generations. These technologies have shown least-cost competitiveness in electricity generation, which describes their importance in sustainable development of the electricity sector. The second is insignificant contribution from solar thermal and solar PV technologies in the entire study period. The high investment costs associated with the technologies discourages the penetration in generations mix despite their least operations and maintenance costs. The last conclusion is the country self-sufficiency in generating electricity using its own local energy resources thus ensuring security of supply for sustainable development.

3.3 Primary energy supply

Primary energy supply composition for electricity generation is as shown in Table 4. Coal, NG, HFO and biomass are the main primary energy supply for electricity generation. Conversion technologies for geothermal, hydro, wind, solar PV and solar thermal do not consume primary energy for electricity generation. Primary energy supply in the BAU scenario will grow from 6 203 GWh in 2010 to 73 083 GWh in 2040. Similarly, the growth in the LEC scenario amounts to 57 529 GWh against 110,700 GWh in the HEC scenario. Generally, all scenarios projects increased coal consumptions as compared to NG with small proportions from biomass and HFO towards 2040. The least-cost supply option, show electricity generation will depend on coal and NG to cover primary energy supply. It further depicts gradually decrease in HFO to less than

Table 4: Primary energy production (2010-2040)

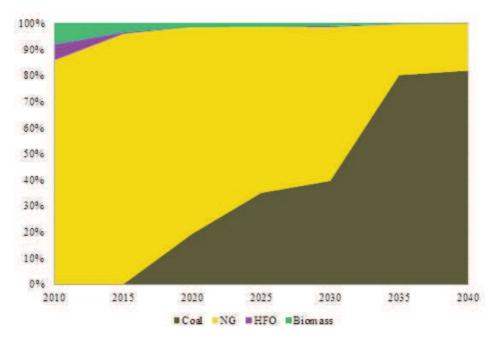|	Coal			Natural gas			HFO			Biomass		
	BAU	LEC	HEC	BAU	LEC	HEC	BAU	LEC	HEC	BAU	LEC	HEC
2010	–	–	–	5326.4	5326.4	5326.4	380.8	380.8	380.8	495.5	495.5	495.5
2015	–	–	–	10469.6	10310.4	11278.5	66.7	63.4	72.5	369.9	367.6	326.9
2020	4235.5	3283.0	6865.4	17314.4	17465.6	17524.9	0.0	–	0.0	313.0	315.7	312.7
2025	6809.8	3283.0	6865.4	12356.9	13519.5	17351.5	21.5	14.3	42.6	242.2	237.6	154.7
2030	4995.2	2366.6	13130.6	7430.1	6801.0	10467.1	52.6	25.4	48.0	126.4	117.4	123.8
2035	27982.2	16905.6	40673.7	6787.2	7933.7	16647.6	41.0	44.4	38.5	91.2	91.2	50.3
2040	59862.6	45949.3	67200.2	13196.3	11555.5	43475.7	24.2	24.2	24.2	–	–	–
Total	103,885	71,787	134,735	72,881	72,912	122,072	587	552	607	1,638	1,625	1,464

Figure 8: Primary energy supply – BAU scenario

0.1% in 2040. Figure 8 depicts primary energy supply in the BAU scenario that is the representative trend for other scenarios.

3.4 CO_2 emissions
The total CO_2 emission depicted in Figure 9 rises from 1182-kilo tonnes of CO_2 in 2010 to 23652.3-kilo tonnes of CO_2 in 2040 for the BAU scenario. The rise in CO_2 emission in the BAU scenario represents an annual growth of 10.5%. Similarly, the increases for LEC and HEC scenarios represent annual growth of 9.5% and 11.7 % respectively. The growth rate in CO_2 emissions in the LEC scenario is much lower than that of HEC and BAU sce-

narios due to slow economic growth presumed in the scenario representing less energy consumption. Similarly, the higher CO_2 emissions in the HEC scenario is highly influenced by higher electricity demands, which resulted in optimal capacity additions of coal and NG power plants. The emission of CO_2 in all scenarios is higher due to insignificant renewable energy conversion technologies applications.

3.5 Economics of scenarios
The capital investment cost required for the entire period of study is based on MESSAGE least cost modelling results. The sharing of capital invest-
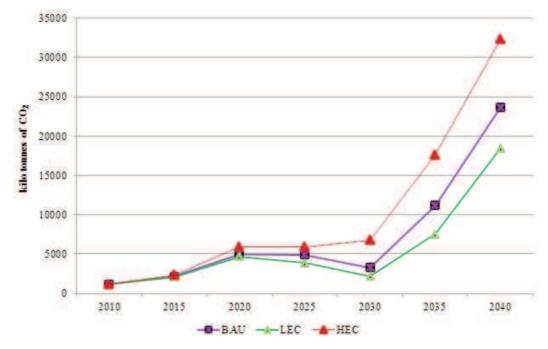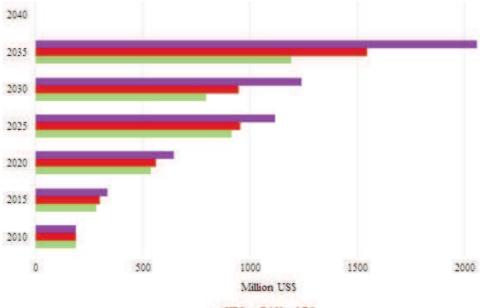

Figure 9: Least cost projected CO_2 emissions (2010-2040)

Figure 10: Capital investment costs for the entire study period (2010-2040)

Table 5: Total investment and O&M costs

Name of Scenario	O&M Variable Cost (Million US$)	O&M fixed cost (Million US$)	Investment cost (Million US$)	Total investment and O&M cost (Million US$)
BAU	999.7	1127.7	4487.6	6615.1
LEC	805.4	1013.4	3900.0	5718.8
HEC	1,334.8	1,222.2	5,595.3	8,152.4

ments for the period of 2010 – 2045 is as shown in Figure 10. In meeting final electricity demand under BAU, LEC and HEC scenarios, the total capital investment cost of 4 488 million US$, 3 903 million US$ and 5 573 million US$ respectively would be required. The main share of the capital investments for the entire period in BAU, LEC and HEC scenarios falls into the period of 2015 to 2035, in which most of the capacity addition is taking place. The capital investment needed to develop a BAU scenario final electricity demand in the entire study period would be about 584 million US$ more than LEC scenario, while 1 086 million US$ increase would be needed for a HEC scenario. The higher capital investment costs are observed in 2035 for HEC and BAU scenarios, while for LEC scenario is in 2030.

Least cost modelling results as presented in Table 5 shows the main differences among BAU, LEC and HEC scenarios in terms of the investment cost and variable and fixed O&M costs. Variable O&M costs for the HEC scenario are 335.1 and 529.4 million US$ higher than those for the BAU and LEC scenarios. Moreover, the LEC scenario entail lower fixed O&M costs at 1013.4 million US$ as compared with the BAU and HEC scenarios.

4. Sensitivity analysis
Sensitivity analyses carried out in this study, intend-

ed to explore the influence of techno-economic parameters, policy options and extreme dry weather conditions in the expansion of the final electricity generation mix.

4.1 Renewable energy penetration
Least-cost optimization results as distinguished in previous sections reveals in-significant penetration into electricity generation of renewable energy technologies due to the high investment costs. Among the reasons behind the insignificant penetration of renewable energy technologies in electricity generation is the absence of non-environmental friendly energy supply constraints. As a result, the market forces decide to choose the least-cost energy supply options for electricity generations, which in most cases, occurs as non-environmentally friendly sources (Bull, 2001; Lewis, 2007). Based on this fact, the study formulates a renewable energy penetration policy option (REPP) as an alternative scenario to study electricity system behaviour under energy supply constraints to promote renewable energy technologies in the generation of electricity. The policy option in REPP requires a compulsory penetration of renewable energy technologies (combined together) to contribute at least 10% of the total electricity generation in 2020 and increasingly to 30% in 2040. The REPP scenario assumes energy demands projections and all techno-eco-

Table 6: Renewable energy penetration between BAU and REPP scenarios

	Scenario	2010	2015	2020	2025	2030	2035	2040
Renewables shares in electricity generation (%)	BAU	2.5	1.2	0.6	4.0	15.4	11.3	9.9
	REPP	2.5	1.2	10.1	15.1	20.7	25.0	30.0
CO_2 emission level (kilo tonnes of CO_2)	BAU	1182.3	2134.0	4982.8	4889.3	3266.5	11189.3	23652.3
	REPP	1182.3	2134.0	3874.6	2927.7	1906.2	4380.7	12198.3
Primary energy supply (GWh)	BAU	6202.7	10906.2	21862.9	19430.5	12604.3	34901.5	73083.1
	REPP	6202.7	10906.2	18778.3	14069.0	8924.9	18971.2	41212.6
Renewables installed capacity shares (%)	BAU	0.0	1.2	0.8	3.1	12.7	9.5	10.6
	REPP	0.0	1.2	17.1	20.7	18.1	24.1	34.7

nomic parameters of the BAU scenario with the additions of the compulsory policy measures. All modelling inputs of REPP scenario remain the same as in the BAU scenario except for the imposed compulsory penetration of renewable energy technologies.

The results of REPP scenario implementations as compared to the BAU scenario in terms of the total installed capacity, electricity generation and CO_2 emissions are as illustrated in Table 6. The MESSAGE results depict a huge reduction of CO_2 emissions at approximately 48% in the REPP scenario as compared to the BAU scenario in 2040. The displacement of thermal power plants with renewable energy technologies has resulted in reduction of CO_2 emissions and primary energy supply. The total installed capacity shares of renewable energy technologies increases to 17.1% and 34.7% in 2020 and 2040 respectively. BAU scenario composition was 0.8% in 2020 and 10.6% in 2040. The shares of renewable energy technologies in the total generation mix for the REPP scenario has increased to 30% in 2040 as compared to 9.9% it had in the BAU scenario. Satisfactory inclusion of renewable energy technologies into the electricity generation mix, as shown in the REPP scenario, has demonstrated the importance of compulsory meas-

ures in policy formulation in favour of renewables.

Even though the compulsory policy measures resulted in the expansion of renewable energy technologies shares, REPP scenario depict additional investments costs as compared to the BAU scenario. The comparison in the investments costs between the BAU and REPP scenarios is as depicted in Figure 11. Meeting REPP scenario requirements will necessitate considerable investment cost of 7 665.8 million US$ as compared to 4 487.6 million US$ for the BAU scenario. Contrariwise, as shown in Figure 12, REPP scenario accommodation exhibits a decrease in the operation and maintenance variable costs (O&M). There is a decrease to 680.6 million US$ in the operation and maintenance variable costs for the REPP scenario, when compared to 999.7 million US$ for the BAU scenario in the entire study period. MESSAGE modelling results; show that the REPP scenario demands a more aggressive approach to investment in renewable energy technologies. For that reason, if the country chooses to implement the policy, additional policies such as renewable energy feed-in tariff and institutional frameworks that are essential for the growth of renewable energy technologies must be in place. The compulsory policy measures as revealed in MESSAGE modelling helps in tapping of the enor-
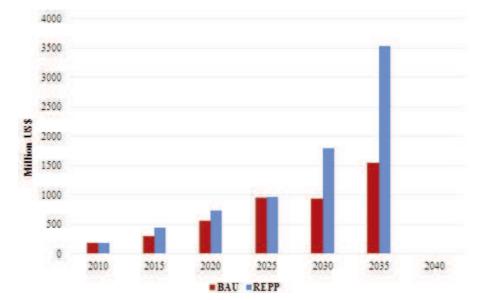

Figure 11: Investments costs comparison between BAU and REPP scenarios

mous potential of renewable energy resources into electricity generations for the benefit of the environment and security of supply.

for the fossil fuel scenarios. A decrease or increase of the discount rate has insignificant influence on capital investments of hydro, biomass and geothermal, which seems to be due mainly to the limited resources potential.
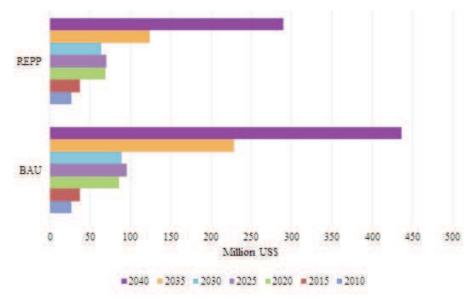

Figure 12: Variable O&M costs comparison between BAU and REPP scenarios

4.2 Discount rate adjustments

Adjustments were carried out on the BAU scenario to approximate the influence of the discount rate on the upcoming pattern of electricity generation capacity, electricity production or economic effectiveness of a number of electricity generation plants. The discount rate adjustments carried out were 6%, 8%, 12% and 14% in comparison to a study-adopted value of 10%. Adjustments of discount rate value to 6% preferred early capacity addition of 500 MW wind power plant into electricity generation in 2035, while 8%, 10% and 12% favours addition in 2040 with no addition for the 14% values. Solar PV and thermal failed to be competitive in all discount rates adjustments. These technologies require special policy option for their inclusion into electricity generation to be realistic. Adjustments of discount rate values to 12% and 14% were in favour of capacity addition of CCGT and GT power plants as opposed to lower values (6% and 8%), which preferred coal power plants. Higher efficiency coupled by a lower operating and maintenance costs, shorter construction time and fuel cost characterizes CCGT and GT power plants thus turn out to be more attractive for capacity addition in comparison to other technologies options. The discounts rates of 6%, 8%, 12% and 14% resulted in coal fired power plants total installed capacity of 6 652 MW, 6 108 MW, 5 385 MW and 4773 MW respectively. In other words, a higher value of discount rate leads to the postponement of large-scale investments. According to the minimum cost criterion, a discount rate of 10% gives greater preference

4.3 Dry weather scenario

Experience has shown weather conditions affect electricity generation capacity causing outages and rationing (Loisulie, 2010; MEM, 2013b). The alternative dry weather scenario was formulated to analyse electricity system behaviour under uncertain weather conditions. All modelling inputs of a dry weather scenario remain the same as in the BAU scenario except for the imposed generation's constraints of hydropower to 20% of the total generations in the period 2020-2040. The least-cost results as shown in Table 7 shows the generations will shift to coal and NG power plants at approximately 42.8% and 30.2% respectively. The capacity additions for coal power plants will expand to 9 772 MW as compared to 6 040 MW in the BAU scenario. Because of imposed hydropower constraints, the CO_2 emission will increase to 86938.67-kilo tonnes of CO_2 as compared to 51296.6-kilo tonnes of CO_2 in the BAU scenario. Based on MESSAGE modelling results, if the country chooses to implement measures because of dry weather conditions, more usage of coal and NG as primary energy supplies will be the least cost option. The additional capacity in terms of coal and NG power plants to replace hydropower plants would decrease both the risks of a dry weather condition and energy security uncertainties. However, the weaknesses of coal and NG development into a dry weather scenario are the higher CO_2 emissions as compared to the BAU scenario as depicted in Figure 13. The capital investment cost of the dry weather scenario will require less than 535.52 million US$ as compared

Table 7: Generation mix by technology dry weather scenario

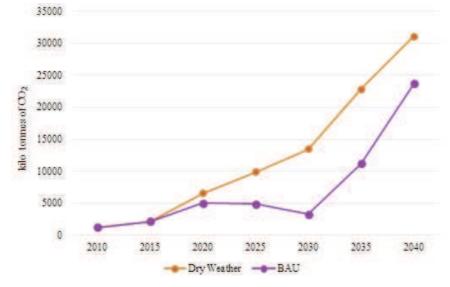|	2010	2015	2020	2025	2030	2035	2040
Coal_PP	-	-	*25.11*	*34.92*	*41.15*	*52.93*	*42.85*
HFO_PP	2.03	0.23	-	-	0.004	0.03	0.01
NG_PP	28.86	54.56	54.41	41.00	22.06	15.60	30.20
CCGT_PP	0.00	76.62	89.11	87.23	92.20	90.55	97.88
GT_PP	100.00	23.38	10.89	12.77	7.80	9.45	2.12
Hydro_PP	66.65	43.98	19.90	20.04	20.23	20.03	16.98
Wind_PP	-	-	-	-	-	-	2.20
Biomass_PP	2.46	1.23	0.59	0.41	0.13	0.07	-
GeoTh_PP	-	-	-	3.63	16.29	11.22	7.71
Solar_PV	-	-	-	-	-	-	-
Solar_Th	-	-	-	-	-	-	-
Electricity Import	-	-	-	-	0.13	0.12	0.05
Total %	100	100	100	100	100	100	100

Figure 13: Comparison in CO$_2$ emissions between Dry weather and BAU scenarios

to capital investment in the BAU scenario. Less capital investment cost in the dry weather scenario is due to lower capital investment cost and shorter construction time of coal coal-fired and NG power plants. Despite hydro power plant lower operation and maintenance costs, coupled with zero fuel consumption for final electricity generation, they have higher capital investment costs and longer construction life (Sharma, 2010).

5. Conclusion

The study presented a modelling approach on the energy supply options for electricity generation in Tanzania. The modelling approach emphasized optimal results based on the least-cost as assumed in MESSAGE. Based on the results presented, MESSAGE turned out to be a useful tool to address energy supply options for electricity generation in Tanzania. The projected total installed capacity increases gradually from 804.2 MW in the base year to 10811 MW, 9190.9 MW and 13325.6 MW in

2040 for the BAU, LEC and HEC scenarios respectively. The increase in the total installed capacity would call for capital investment cost of 4 488 million US$, 3 903 million US$ and 5 573 million US$ respectively for the BAU, LEC and HEC scenarios.

Hydropower plants dominate the capacity additions followed by coal, CCGT, geothermal and GT power plants to meet the electricity generation expansion in both scenarios. Total primary energy supply dominated by coal and NG rises to 73 083 GWh, 57 529 GWh and 110 700 GWh in 2040 for the BAU, LEC and HEC scenarios respectively, as compared to base year amount of 6 203 GWh. In meeting final electricity demands, CO$_2$ emissions will expand from 1182-kilo tonnes of CO$_2$ to 10.5%, 9.5% and 11.7% respectively for BAU, LEC and HEC scenarios with decreases of CO$_2$ in the REPP scenario.

Renewable energy sources as concluded in the REPP scenario were identified as promising for meeting the future electricity demand in Tanzania.

Potential contribution of renewable energy sources to the savings of coal and NG reserves would be a great contribution to the economy and the environment. However, the dry weather scenario has shown a shift to coal and NG power plants generations at approximately 42.8% and 30.2% respectively resulting into higher CO_2. The sensitivity analysis tests results have shown lower discount rates to favour investments on wind and coal power plants, while higher discount rates favour NG power plants. The least-cost results have shown implications concerning capital investment costs versus environmental impacts concerns. Least cost modelling results have concluded that meeting final electricity demands without considerations of environmental impacts concerns is cheaper. Policy makers should balance the capital investment costs and environmental concerns in the energy planning of the country.

Acknowledgments

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