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Screening Power Plants for Green-Based Generation Expansion Planning for Kenya

Patrobers Simiyu
Institute of Energy & Environmental Technology (IEET); Jomo Kenyatta University of Agriculture & Technology; Kenya

Abstract: *The main concern in the global generation sector was the huge CO_2 emissions from the conventional power generation. In Kenya, the sector prepares 20 year rolling least cost power development plan (LCPDP) for expanding the power system to meet the current and future power demands. The 2011-2031 LCPDP generation plan proposed a system expansion that would result in a 33% fossil fuel power generation posing a huge CO_2 emission dilemma. However, renewable energy integration in the least-cost generation expansion planning (GEP) was considered key to energy security and emission reduction. During GEP, the screening curves are useful preliminary tool in selecting candidate generation options. In this study the screening curves were used in vetting the candidate plants for green-base GEP in Kenya. The findings showed that the green base load candidate plants were namely; 140MW Geothermal, 140MW low grand falls hydro, 300MW Wind, 1000MW imports, 60MWMutonga hydro and 1000MW nuclear plants characterized by US$ 90-660/kW.yr fixed cost, more than 40% capacity factor and US$cts 6-13/kWh levelized cost of electricity (LCOE). Suitable green peaking plant were 180MW GT-Natural gas, 100MW Solar PV and imports depicted by US$ 100-700/kW.yr fixed cost, less than 40% capacity factor and US$cts 15-30/kWh LCOE. These were a mix of green generation plants for cost effective utilization and environmental sustainability in Kenya. Therefore, the research recommended the selected candidate plants for simulation and optimization of a green-based generation expansion plan for Kenya using relevant GEP models.*

Key Words*: annual generation cost curves; base load plants; generation expansion planning; levelized cost of electricity; screening curves; peaking plants.*

I. Introduction

The growing concerns for climate change mitigation in the generation sector have driven many countries in the world towards environmentally-benign generation investments [1]; [2]. Renewable energy (RE) is regarded as an appropriate clean power alternative to the conventional carbon intensive plants [3]; [4]. Consequently, RE integration in least-cost generation expansion planning (GEP) is considered key to energy security and emission reduction [5]; [6].

In Kenya, the sector prepares 20 year rolling least cost power development plan (LCPDP) at the energy regulatory commission (ERC) for expanding the power system to meet the current and future power demands. The 2011-2031 LCPDP had significant RE composition [7]. However, there was room for more integration because the planned large hydropower and heavy fuel oil (HFO) dominated power generation posed serious challenges. According to [8], the large hydros were vulnerable to acute energy shortfalls due to the frequent droughts. Conversely, the HFO and the planned conventional coal power plants posed the CO_2 emissions dilemma [9].

However, Kenya owns huge under-exploited RE resources yet for exploitation. Therefore this study assessed the Kenya generation potential using the screening curves with the aim of identifying a portfolio of sustainable RE candidate plants for green-based GEP. This would stimulate the Kenya generation sector in adopting a more sustainable GEP towards security of power and CO_2 emission reductions. In addition, as a regional hub in social-economic development, Kenya will stand as a benchmark for many countries in Africa and beyond. This paper is divided into seven sections. The section two gives an overview of the screening curves. Section three presents the RE potential in Kenya. Section four outlines the study methodology. Section five gives the results. Section six gives the discussion while the last section gives the conclusion and recommendation for future research.

II. Screening Curves

The screening curve analysis (SCA) involves preliminary vetting of candidate generation sources to establish the most economical supply option. In this approach, the total costs during the operating life of the potential options are discounted and plotted against capacity factor values. The resulting screening curves captures major trade-offs between capital and operating costs and the utilization levels of various generation technologies allowing higher cost options to be excluded for further consideration [10].

In the SCA, the annual total generation cost (AGC) is represented as a function of variable fuel cost (VFC) and variable operation and maintenance cost (VOMC). The annualized capital cost (ACC) and fixed operation and maintenance cost (FOMC) are held constant. The linear equation (1) shows the screening curve expression [11].

$$\mathrm{AGG} = \{\mathrm{ACC} + \mathrm{FOMC} + (\mathrm{VFC} + \mathrm{VOMC}).\mathrm{T}\} \qquad (1)$$

Where: *ACC;* Annualized capital cost per MW, *FOMC;* Fixed operation and maintenance cost per MW per year, *VFC;* Variable fuel cost per MWh, *VOMC;* Variable operation and maintenance cost per MWh and *T*; total year operating hours for the given MW.

Additionally, the screening curves integrated with the load duration curve (LDC) can give an appropriate mix of plants to minimize the total generation cost of a power system. In this way, the screening curves are positioned on the upper half while the LDC placed on the lower half. By projecting the intersection point from the screening curves onto the LDC, the portion of generation capacity that would be supplied from the plants captured in the screening curves is yielded [10]; [12].

However, SCA is inadequate for GEP as it doesn't capture the complex and diverse power generation parameters such as system reliability, resource capacity constraints, related uncertainties as well as the existing generation system [12]; [11]. For this reason, numerous and sophisticated GEP models extensive in literature are available for effective simulation of the generating system's operation and subsequently optimizing the generation expansion plan [13]. Nevertheless, prior to the process, the screening curves are useful preliminary screening tool in selecting candidate generation plants [12].

III. Renewable Energy Potential In Kenya

Kenya is well endowed with enormous RE resources. The hydropower potential in Kenya totals 1670MW but only 807MW of this capacity is installed. Detailed hydropower assessments revealed a 700MW High Grand Falls potential project along the Tana River and a further 100MW at Karura. Additionally, Mutonga (60MW) and low grand falls (LGF) (140MW) sites were found suitable for immediate development. Moreover feasibility studies established Ewaso Ng'iro South River (220MW) and the North-Rift Valley basin at Arror (70MW) [9].

The geothermal resources mainly situated within the Kenya's East African Rift system are currently installed at 250.4MW. Detailed exploration studies revealed that the potential geothermal sites have a total generation of 5,000 – 10, 000 MWe. The prospects are clustered mainly into Central Rift (1,800MW), South Rift (2,400MW) and North Rift (3,450MW) [9] [14].

Kenya's strategic location along the equator offers great potential of about 4-6 KWh/m^2/day of daily insolation for solar power. This potential is spread in many parts of the coast, north eastern, eastern amongst other parts of the country [15]. The total area capable of delivering 6KWh/m^2 per day is about 106, 000 km^2 with a potential of 638, 790 TWh for solar photovoltaic (PV) and thermal though less than 1% is in use [16]; [17].

Additionally, a huge potential of about 346W/m^2 and wind speeds of over 6m/s for wind power generation exists. On average about 90,000 Km^2 of area in the country have very excellent wind speeds of 6m/s yet a meager 5.3MW is currently installed [9]. Nonetheless, the steady growing interest in wind power is significantly increasing its role in the Kenya electricity mix for grid and off-grid power systems [15].

Moreover, there are commercially exploitable coal reserves discovered in the Mui basin in Kitui County besides the RE potential. In the 2011-2031 LCPDP, conventional coal power generation was projected to come on line in 2015 and by 2030 it would provide 4500MW of power. Nevertheless, the projected use of the coal technology will increase the CO_2 emissions to record levels contradicting the climate change mitigation strategies [8].

Furthermore, there are other cost-effective energy resources within Kenya's reach. There are at least 2000MW hydropower imports from Ethiopia. Secondly, about 2340MW Natural gas imports and local reserves are available for 180MW combined cycle gas turbine (CCGT) plants. Finally, the country has adopted a systematic international methodology of developing the nuclear infrastructure for commissioning its first ever 1000MW nuclear power plant by 2024 [7].

IV. Methodology

The candidate generation plants from the Kenya's available energy resources for the study include; 140MW geothermal, 1000MW nuclear, 300MW coal, 180MW Gas Turbine (GT)-Kerosene, 180MW GT-Natural gas, 160MW heavy fuel oil (HFO), 1000MW imports, 60MW Mutonga hydro, 140MW low grand falls (LGF), 300MW wind and 100MW solar photovoltaic (PV). A generation cost model (GCM) was set up in the Microsoft Excel encompassing each candidate plant. The GCM was mainly comprised of power generation technical and economic power generation characteristics namely; fixed & variable generation costs, total outage rate (TOR), outage adjustment factor (OAF), interim replacement (IR), interest during construction (IDC) and capital recovery factor (CRF). Figure 1.0 shows the GCM outline for the candidate plants.

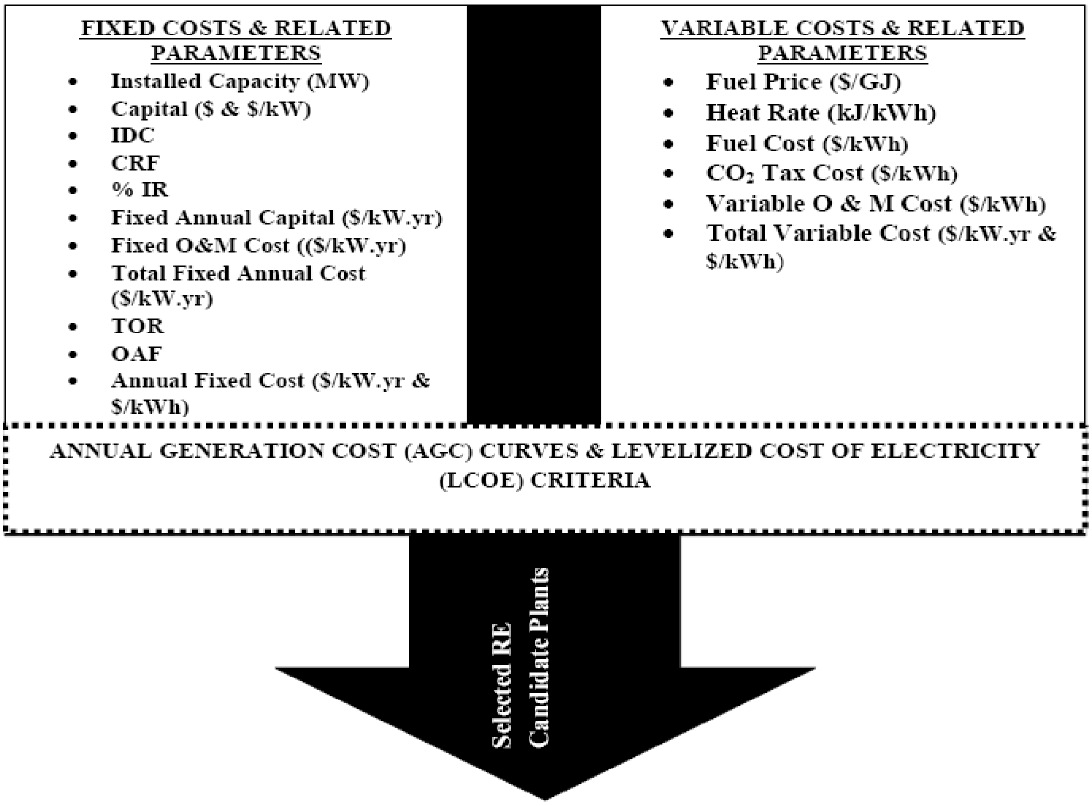

Figure 1.0: GCM Outline for the Candidate Generation Plants

The equations (2) to (10) were used to represent the power generation characteristics for all the candidates in the GCM.

$$\text{Capital }(\$X10^6) = \frac{\text{Installed Capacity (MW) X Capital (\$/kW)}}{(10^3)} \quad \ldots(2)$$

$$\text{Fixed Annual Capital}(\$/\text{kW.yr}) = \{\text{Capital}(\$/\text{kW})\ \text{X}(\text{IDC Factor})\text{X}(\text{CRF} + \text{IR})\} \quad \ldots(3)$$

$$\text{Total Fixed Annual Cost}(\$/\text{kW.yr}) = \{\text{Fixed Annual Capital}(\$/\text{kW.yr}) + \text{Fixed O}\&M(\$/\text{kW.yr})\} \quad \ldots(4)$$

$$\text{OAF} = \frac{1}{(1-\text{TOR})} \quad \ldots(5)$$

$$\text{Annual Fixed Cost}(\$/\text{kW.yr}) = \{\text{Total Fixed Annual Cost}(\$/\text{kW.yr})\ \text{X}(\text{OAF})\} \quad \ldots(6)$$

$$\text{Annual Fixed Cost}(\$/\text{kWh}) = \frac{\text{Annual Fixed Cost (\$/kW.yr)}}{(8760)} \quad \ldots(7)$$

$$\text{Fuel Cost}(\$/\text{kWh}) = \frac{\text{Fuel Price (\$/Gj) X Heat Rate (kJ/kWh)}}{(10^6)} \quad \ldots(8)$$

$$\text{Total Variable Cost}(\$/\text{kWh}) = \{\text{Fuel Cost}(\$/\text{kWh}) + CO_2\ \text{Tax Cost}(\$/\text{kWh} + \text{Variable O}\&M\ Cost(\$/\text{kWh})\} \quad \ldots(9)$$

$$\text{Total Variable Cost}(\$/\text{kW.yr}) = \{\text{Total Variable Cost}(\$/\text{kWh})\ \text{X}\ 8760\} \quad \ldots(10)$$

The GCM was used to evaluate the annual generation cost (AGC) for each candidate plant as a function of the annual variable cost (AVC); the annualized fixed cost (AFC) held constant. These cost variables for the candidates are shown in the AGC curve expression in equation (11). In this linear equation, the AFC is the intercept while the AVC, the slope.

$$\text{AGC}(\$/\text{kW.yr}) = \{\text{AVC}\ (\$/\text{kW.yr}).(\%\ \text{CapacityFactor}) + \text{AFC}(\$/\text{kW.yr})\} \quad \ldots(11)$$

Similarly, the levelized cost of electricity (LCOE) for each candidate plant was calculated. The total variable cost (TVC), AFC and capacity factor were key LCOE components. The LCOE expression is represented using equation (12).

$$\text{LCOE}(\$/\text{kWh}) = \text{TVC}\ (\$/\text{kWh}) + \frac{\text{AFC (\$/kW.yr)}}{(8760\ \text{X}\ \%\ \text{Capacity Factor})} \quad \ldots(12)$$

The AGC and the LCOE screening curves were used in the selection of the base load and peaking RE candidate plants for GEP.

V. Results

The generation cost model (GCM) was developed for screening the candidate generation plants. Table 1.1 presents the GCM for the candidate generation plants. From table 1.1, the capital costs widely varied across the candidate plants. Solar PV had the highest capital cost of US$4450/kW.yr while the imports had the lowest of about a tenth of the solar PV's capital cost (US$455/kW.yr). On the other hand, the fuel cost was quite significant in GT-kerosene had the highest fuel cost at U$cts 22.2/kWh while HFO the least at U$cts 9.1/kWh. The RE such as solar PV, wind, low grand falls (LGF), Mutonga hydro, imports and geothermal had no fuel costs.

Table 1.1: Candidate Generation Plants' Generation Cost Model (GCM).

	Geothermal	**Nuclear**	**Coal**	**GT-KERO**	**GT-N.GAS**	**HFO**	**Import**	**Mutonga**	**LGF**	**Wind**	**Solar PV**
Configuration (n x MW)	**1 x 140**	**1 X 1000**	**1 X 300**	**1 x 180**	**1 x 180**	**1 x 160**	**1000**	**1x60**	**1x140**	**300**	**100**
Total Capacity (MW)	140	1000	300	180	180	160	1000	60	140	300	100
Fixed Cost											
Capital ($ x 10^6)	511	4055	631	135	135	218	455	259	507	690	445
Capital ($/kW)	3650	4055	2104	750	750	1364	455	4314	3621	2300	4450
IDC Factor	1.1344	1.2605	1.1341	1.0725	1.0725	1.0654	1.0654	1.3378	1.3378	1.0654	1.1380
Annuity Factor (or C.R.F.)	0.0937	0.0839	0.0937	0.1019	0.1019	0.1019	0.0937	0.0817	0.0817	0.0937	0.1114
Interim Replacement	0.921%	0.68%	0.921%	0.35%	0.35%	0.35%	0.35%	1.03%	0.87%	0.64%	0.63%
Fixed Annual Capital ($/kW/yr)	426.0	463.6	245.5	84.7	84.7	153.1	47.1	531.4	438.2	245.3	596.1
Fixed O&M Costs ($/kW/yr)	56.0	90.0	63	11.8	11.8	62.5	30.0	21.3	19.8	28.1	39.0
Total Fixed Annual Cost ($/kW/yr)	482	554	309	97	97	216	15	553	458	273	635
Total Outage Rate (TOR)	0.068	0.150	0.156	0.078	0.078	0.098	0.150	0.0969	0.0969	0.100	0.091
Outage Adjustment Factor (OAF)	1.073	1.177	1.185	1.085	1.085	1.108	1.176	1.107	1.107	1.111	1.100
Annual Fixed Cost ($/kW/yr)	**517**	**652**	**366**	**105**	**105**	**239**	**91**	**612**	**507**	**304**	**699**
Annual Fixed Cost ($/kWh)	**0.0590**	**0.0744**	**0.0417**	**0.0120**	**0.0120**	**0.0273**	**0.0104**	**0.0699**	**0.0579**	**0.0347**	**0.0798**
Variable Cost											
Fuel Price ($/GJ)	-		4.557	19.37	9.11	11.08	-	-	-	-	-
Heat Rate (kJ/kWh)	-		10900	11,440	11,447	8,197	-	-	-	-	-
FuelCost($/kWh)	-	0.0087	0.0497	0.2216	0.1043	0.0909	-	-	-	-	-
CO_2 Tax Cost ($/kWh)	-		0.0221	0.0089	0.0066	0.0089	-	-	-	-	-
Variable O&M Cost ($/kWh)	0.00557	0.0049	0.0036	0.0120	0.0010	0.0089	-	0.0053	0.0053	0.0010	0.0010
Total Variable Cost ($/kWh)	**0.00557**	**0.0136**	**0.0754**	**0.2425**	**0.1119**	**0.1087**	**0.0500**	**0.0053**	**0.0053**	**0.0010**	**0.0010**
Total Variable Cost ($/kW/yr)	**49**	**119**	**660**	**2124**	**980**	**952**	**438**	**47**	**47**	**9**	**9**

				Unit Cost ($/kW.yr)							
Capacity Factor	**Geo**	**Nucl**	**Coal**	**GT-KER**	**GT-N.GA**	**HFO**	**Impo**	**Muto**	**LGF**	**Wind**	**SoPV**
0%	517	652	366	105	105	239	91	612	507	304	699
10%	522	663	432	317	203	334	135	617	512	305	700
20%	527	675	498	530	301	429	178	621	517	305	700
30%	532	687	564	742	399	525	222	626	521	306	701
40%	536	699	630	954	497	620	266	631	526	307	702
50%	541	711	696	1167	595	715	310	635	531	-	-
60%	546	723	762	1379	693	810	354	640	535	-	-
70%	551	735	828	1592	791	905	397	-	-	-	-
80%	556	747	894	1804	889	1001	441	-	-	-	-
90%	561	759	960	2017	987	1096	485	-	-	-	-
100%	566	770	1026	2229	1085	1191	529	-	-	-	-

				Unit Cost ($/kWh)							
Capacity Factor	**Geo**	**Nucl**	**Coal**	**GT-KER**	**GT-N.GA**	**HFO**	**Impo**	**Muto**	**LGF**	**Wind**	**SoPV**
10%	0.5957	0.757	0.493	0.362	0.231	0.382	0.154	0.704	0.584	0.348	0.799
20%	0.3006	0.385	0.284	0.302	0.172	0.245	0.102	0.355	0.295	0.174	0.400
30%	0.2023	0.262	0.215	**0.282**	**0.152**	**0.200**	0.085	0.238	0.198	0.117	0.267
40%	0.1531	0.200	0.180	0.272	0.142	0.177	0.076	0.180	0.150	**0.088**	**0.200**
50%	0.1236	0.162	0.159	0.266	0.136	0.163	0.071	0.145	0.121	-	-
60%	0.1039	0.138	**0.145**	0.262	0.132	0.154	0.067	**0.122**	**0.102**	-	-
70%	0.0899	0.120	0.135	0.260	0.129	0.148	0.065	-	-	-	-
80%	0.0793	**0.107**	0.128	0.257	0.127	0.143	0.063	-	-	-	-
90%	**0.0711**	0.096	0.122	0.256	0.125	0.139	**0.062**	-	-	-	-
100%	0.0646	0.088	0.117	0.254	0.124	0.136	0.060	-	-	-	-

The annualized fixed costs (AFC) & annualized variable costs (AVC) for the candidate plants at varied capacity factors yielded the annual generation cost curves (AGC). Figure 1.1 shows AGC curves realized for the candidate plants. Similarly, the unit cost or levelized costs of electricity (LCOE) for the candidate plants at varied capacity factors generated the LCOE curves. Figure 1.2 shows the LCOE for candidate plants.

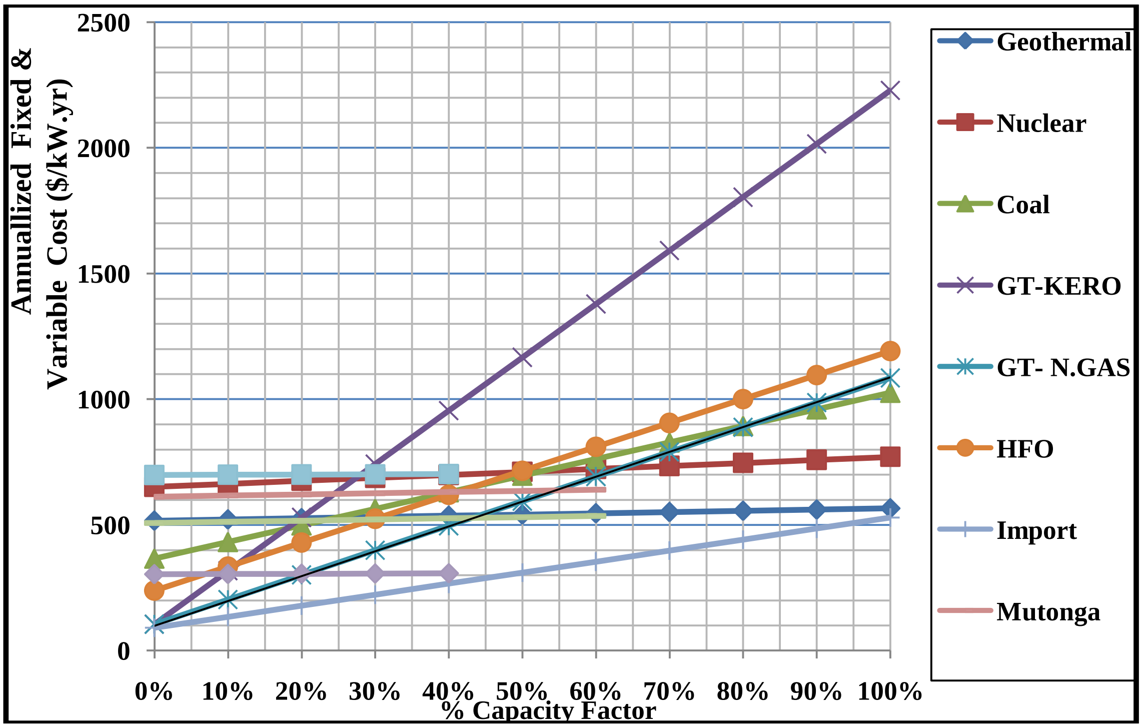

figure 1.1: AGC Curves for candidate plants

The results in figure 1.1 show that solar PV had the highest AFC of US$ 699/kW.yr while the Ethiopia's hydropower imports the least at US$ 91/kW/yr. On the contrary, GT-kerosene incurred the highest AVC of US$ 2124/kW.yr while wind and solar PV the least at US$ 9/kW.yr each. On the other hand, the results in figure 1.2 show that solar PV at 30% capacity factor cost highest at US$cts 20/kWh while hydropower imports from Ethiopia at 90% capacity factor cost the least at US$cts 6.2/kWh.

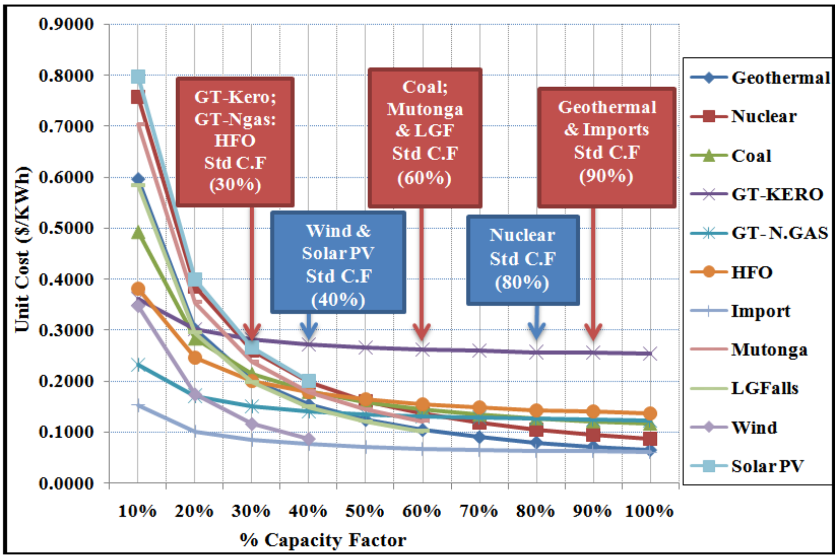

figure 1.2: LCOE curves for candidate plants

The results in figure 1.1 collaborated with figure 1.2 distinguished base loads from peaking power plants. The base load and peaking candidate power plants are displayed in table 1.2. In table 1.2, it was observed that at high capacity factor of above 40%, the base load candidates incurred at higher AFC than AVC and low LCOE. However, the case for the 300MW coal was rather incomparable with all the other base load plants. The Coal plant had an AFC of US$ 366 per kW.yr lower than the AVC of US$ 660 per kW.yr. Besides, its LCOE was the highest in relation to all the other base load candidate plants.

On the contrary, at low capacity factor of 30% and 40%, the peaking candidate plants had higher AVC than AFC and high LCOE. However, this was exceptional for 100MW solar PV which had a lower AVC of US$ 9 per kW.yr than AFC of US$ 699 per kW.yr. Although, solar PV and 160MW HFO had the same LCOE of US$cts 20/kWh; the HFO's relatively higher AVC of US$ 952 per kW.yr gave solar PV the comparative advantage as a better peaking plant. Similarly, the 180MW GT-kerosene was as unfavorable peaking plant as HFO on account of its highest AVC.

Table 1.2: Base Load and Peaking Candidate Plants

SNo.	Candidate Generation Plants	Annual Fixed Cost ($/kW/yr)	Annual Variable Cost ($/kW/yr)	LCOE ($cts/kWh)	% Capacity Factors	Plant Type
1	140MW Geothermal	517	49	7.1	90	Base Loads
2	300MW Wind	304	9	8.8	40	Base Loads
3	140MW LGF	507	47	10.2	60	Base Loads
4	1000MW Nuclear	652	119	10.7	80	Base Loads
5	60MW Mutonga hydro	612	47	12.2	60	Base Loads
6	300MW Coal	366	660	14.5	60	Base Loads
7	1000MW Imports	91	438	6.2	90	Both
8	180MW GT-Nat Gas	105	980	15.2	30	Peak Loads
9	160MW HFO	239	952	20.0	30	Peak Loads
10	100MW Solar PV	699	9	20.0	40	Peak Loads
11	180MW GT-Kero	105	2124	28.2	30	Peak Loads

Consequently, 140MW geothermal, 140MW LGF hydro, 300MW wind, 1000MW imports, 60MW mutonga hydro and 1000MW nuclear plants were selected as suitable green base load plants while coal was excluded. On the other hand, 180MW GT-natural gas and 100MW solar PV plants were suitable green peaking plants while 160MW HFO and 180MW GT-kerosene were barred. The abundant hydropower imports from Ethiopia served both as a base and peaking power plant.

VI. Discussion

The results from the annual generation cost (AGC) and the levelized cost of electricity (LCOE) curves were used to select suitable base load and peaking plants for GEP. According to [12]; [11], the AGC and LCOE curves are used during preliminary screening of generation plants. An appropriate mix of candidate plants minimizes the total generation cost. Therefore, green base load plants were identified as those with high fixed costs (US$ 90-660/kW.yr), high capacity factor (more than 40%) and low LCOE (US$cts 6-13/kWh) namely; 140MW Geothermal, 140MW LGF hydro, 300MW Wind, 1000MW imports, 60MW Mutonga hydro and 1000MW nuclear plants.

Additionally, suitable green peaking plants were recognized as those with low fixed costs (US$ 100-250/kW.yr), low capacity factor (less than 40%) and high LCOE (US$cts 15-30/kWh). The 180MW GT-Natural gas was the main peaking option. Although 100MW Solar PV had the highest fixed cost (US$660/kW.yr), low capacity factor (40%) and high LCOE (US$cts 20/kWh); it was classified as a peaking plant on account of its intermittent nature. Additionally, the imports were considered partly as a peaking plant on account of it abundance and relatively low cost. The characteristics for the base load and peaking plants and related energy technologies were extensive in literature as cited by [10]; [13]; [11]. In addition, the selected power plants were majorly clean and RE in accordance to the classification by [5]; [13]; [4].

As a matter of fact, Kenya was well placed to plan for exploitation of these enormous candidate energy resources for the following reasons. The 60MW Mutonga and 140MW LGF hydropower sites were due for immediate development [9]. Besides; the abundant unexploited feasible geothermal totaling to 7600MW existed [14] for shifting the base load generation from the vulnerable hydropower [9]. Moreover, the Kenya's strategic location along the equator offered about 638, 790 TWh potential for solar PV as a potential peaking substitute for the expensive HFO power [16]; [17]. Furthermore, a huge potential of about 346W/m^2 for wind base load power generation exists [15]. Moreover, an effective green generation portfolio required a proportion of other resources for higher generation system's reliability and stability [5]. Subsequently, there were at least 2000MW hydropower imports from Ethiopia, about 2340MW natural gas and about 4000MW nuclear potential [7]. This was a secure and reliable green-based generation portfolio for security of power and CO_2 emission reduction.

VII. Conclusion And Recommendation

The selected green base load candidate plants for GEP were those with US$ 90-660/kW.yr fixed costs, more than 40% capacity factor and US$cts 6-13/kWh LCOE namely; 140MW Geothermal, 140MW LGF hydro, 300MW Wind, 1000MW imports, 60MW Mutonga hydro and 1000MW nuclear plants. Additionally, suitable green peaking plants were those with US$ 100-250/kW.yr fixed costs, less than 40% capacity factor and US$cts 15-30/kWh LCOE namely 180MW GT-Natural gas and 100MW Solar PV. Additionally, the plentiful imports served as a peaking plant. This was a mix of green generation plants for cost effective utilization and environmental sustainability in Kenya. Therefore, the research recommended the selected candidates for simulation and optimization of a green-based generation expansion plan for Kenya using relevant GEP models.

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