Planning Development of Ethiopia's Hydropower Resources

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1 Introduction

As part of the recently completed Ethiopia Power System Expansion Master Plan Study, the task of deriving an optimised generation expansion plan covering the next 25 years was complicated by : the requirement to consider some 44 existing and candidate hydropower plants and 40 associated storage reservoirs; cascade developments within eight separate river basins; pronounced seasonal variations in natural river inflows, and the historic occurrence of severe multi-year droughts; pronounced seasonal variations in the availabilities of other renewable forms of electricity generation, including wind, solar and biomass; high forecast growth rates of domestic electricity demand, and opportunities for the export of significant amounts of electrical energy to neighbouring countries.

The paper describes the efforts made to take these and other factors into account within the planning process, and the way in which applications of the commonly used WASP computer program were combined with those of software for simulating and optimising the operation of integrated electricity supply systems (AQUARIUS) and rapidly evaluating the performance of alternative expansion plans (EPSIM). Particular emphases are placed on the way in which the conjunctive operation of large reservoirs was modelled, so as to reflect the benefits from cascade development and different storage characteristics, and the importance of taking into account seasonal variations in the availability of other types of generating plant when estimating hydro plant capabilities. Conclusions are drawn, and suggestions made regarding the desirability and feasibility of modelling multiple demand areas, and simultaneously optimising the commissioning of transmission links and interconnections with neighbouring countries, in addition to new interdependent generating capacity.

2 Background

Ethiopia has one of the highest hydroelectric potentials in Africa and the government has ambitious plans for developing the country's economy and rapidly increasing its power supply capabilities. Geographically, the country can be divided into eight river basins, the largest of which are the Abay, or Blue Nile, which flows from Lake Tana in the north to the border with Sudan before joining the White Nile at Khartoum, and the Omo which flows south and enters Lake Turkana in Kenya (Figure 1). In 2012 the country's population was estimated to be 79.2 million, of which some 26.5% had access to electricity.

In recent years generating capacity serving the Inter Connected System (ICS) has been transformed by the commissioning of a number of large hydroelectric plants, including Gibe I (210 MW - 2004), Tekeze I (300 MW - 2009), Beles (460 MW - 2010), and Gibe II (420 MW - 2010). In 2012, additional generating capacity was provided by the 5 MW Aluto Langano I geothermal plant and the 30 MW Ashegoda I and 51MW Adama I wind farms.

Between 2013 and 2019 committed non-hydro generation plant includes the 90 MW Ashegoda II wind plant, the 75 MW Aluto Langano II geothermal unit, a 25MW Energy from Waste plant in the capital Addis Ababa, some 448 MW of capacity at sugar factories, 120 MW of biomass and some 78 MW of diesel capacity. While these plants will provide a degree of back-up capability, the dependency of the ICS on hydropower will be further increased by plants currently under construction, namely Genale Dawa III (254 MW), Gibe III (1,870 MW) and Grand Renaissance (6,000 MW) which, at the time of the study, were expected to be commissioned in 2015 and 2017 respectively.

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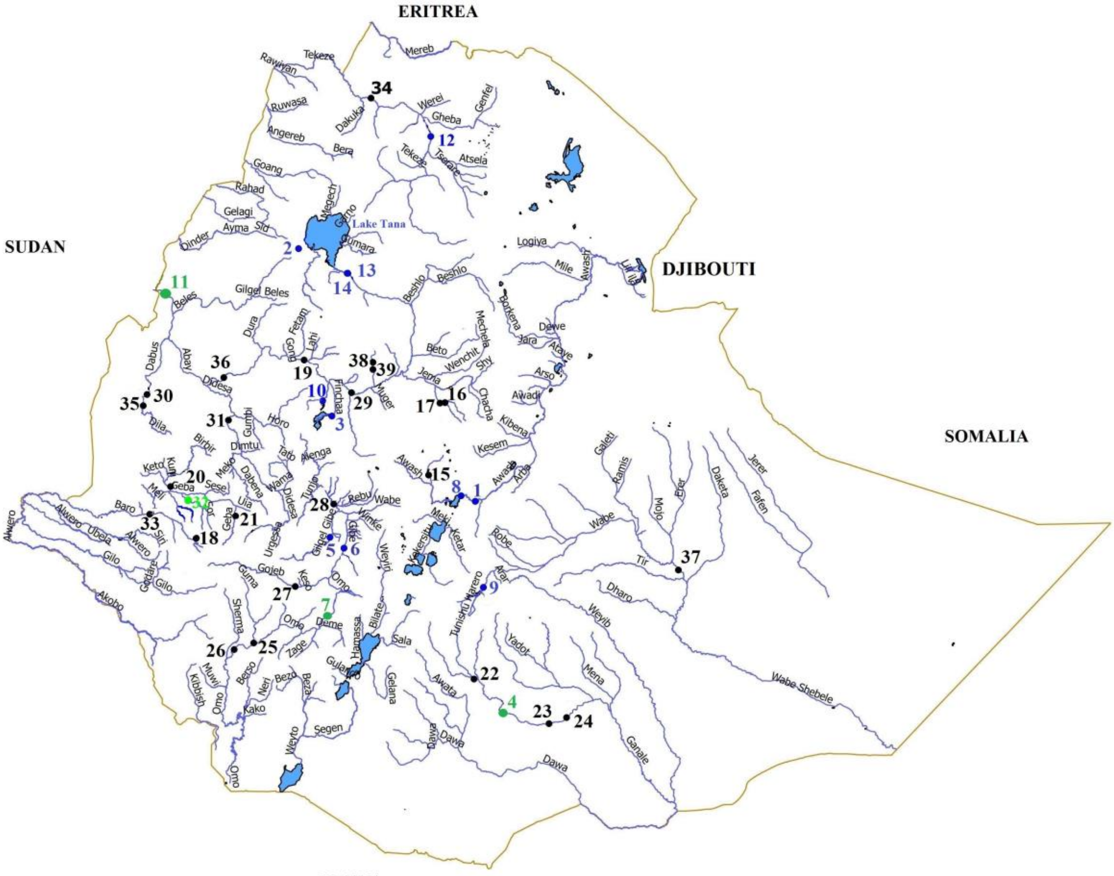

Figure 1 : Main Ethiopian Rivers and Hydro Project Locations

When completed the Grand Renaissance project, situated on the Blue Nile some 25 km from the Sudanese border, will have the largest installed capacity of any hydropower plant in Africa and is expected to generate significant amounts of energy for export to neighbouring countries. In addition to existing 230 kV connections with Djibouti and Sudan, a +/- 500 kV 2,000 MW DC link to Kenya, a second 230 kV line to Djibouti and a 500 kV interconnector to Sudan are planned.

3 Power System Expansion Masterplan Study

In August 2012 the Ethiopian Electric Power Corporation (EEPCO) contracted the firm of Parsons Brinckerhoff UK to carry out a World Bank funded Power System Expansion Masterplan Study. Objectives of the study were to develop plans to best supply forecast domestic and potential export demands for electrical energy over the 25 year period from 2013-2037, and to provide the capability of updating such plans in the future. In particular, the study was designed to indicate how best to exploit Ethiopia's hydropower potential, while giving adequate consideration to the optimal roles of both conventional (thermal and geothermal) and non-conventional (wind, solar and biomass) forms of generation. Candidate hydro projects were to be as defined by already completed studies. As tends to be common practice, optimisation of the generation expansion plan was followed by determination of the most cost effective connections and extensions to the existing transmission system.

Work began on the 1st of October 2012 together with the EEPCO planning team and was essentially completed in February 2014. On inception, a total of 45 existing and potential hydro plants and 40 associated medium to long-term storage reservoirs were identified for inclusion in the study, significantly exceeding the numbers originally envisaged. These are listed in Table 1 together with some of their principal parameters.

The table illustrates the wide range of installed capacities (6 to 6,000 MW) and average flows (between 7 and 1,064 m^3/s), while associated reservoirs are estimated to provide up to 760 'days of storage', this being the active storage divided by the mean daily inflow.

Hydroelectric	Entry	Average	Installed	Energy Generation (2)		Plant	Project	Head Defining and	Average	Active	
Plant	Date	Flow	Capacity	Minimum	Average	Factor	Location	Other Reservoirs (1)	Inflow (2)	Storage	
Model Name (3)	year (4)	m3/s	MW	GWh/a	GWh/a	-	Map #	Model Name(s) (3)	m3/s	Mm3	days
Abu Samuel HEP		6.9	6	12	16	0.30	15	Abu Samuel RES	6.9	-	-
Aleltu East HEP		12.8	189	375	801	0.48	16	Rikicha Gomoro RES	12.8	409	371
								Chacha RES	4.63	159	397
Aleltu West HEP		15.6	265	640	1,066	0.46	17	Aleltu West RES	15.54	34	26
								Jida RES	8.39	551	760
								Weserbi RES	1.9	34	210
Awash II HEP	*1996	58.6	32	149	183	0.65	1	-	58.6	-	-
Awash III HEP	1971	58.6	32	150	184	0.66	1	-	58.6	-	-
Baro 1 HEP	2024	74.8	166	506	652	0.45	18	Baro 1 RES	74.6	993	154
Baro 2 HEP	2024	77.1	507	1,550	1,955	0.44	18	Baro 2 RES	77.2	18	3
Beko Abo HEP	2022	646.4	935	4,445	6,617	0.81	19	Beko Abo RES	647.7	1,235	22
Beles HEP	2010	32.1	460	1,357	2,749	0.68	2	Lake Tana	192.0	9,130	550
Birbir R HEP	2023	105.5	467	1,949	2,717	0.66	20	Birbir R RES	105.4	2,490	273
Finchaa HEP	1973	15.0	128	422	615	0.55	3	Finchaa RES	21.5	788	424
								Amerti RES	5.0	40	92
Geba 1 HEP	2020	31.7	215	462	952	0.51	21	Geba 1 RES	32.4	1,050	375
Geba 2 HEP	2020	50.6	157	488	753	0.55	21	Geba 2 RES	51.4	1,685	380
Genale 3 HEP	2015	98.0	254	1,124	1,691	0.76	4	Genale 3 RES	100.9	1,200	138
Genale 5 HEP	2025	103.3	100	361	573	0.65	23	Genale 5 RES	103.5	139	15
Genale 6 HEP	2020	104.1	246	1,039	1,528	0.71	24	Genale 6 RES	104.3	210	23
Genji HEP	2024	41.8	214	620	909	0.48	18	Genji RES	41.8	5	1
Gibe I HEP	2004	44.1	210	610	882	0.48	5	Gibe I RES	61.8	718	134
Gibe II HEP	2010	43.0	420	1,400	2,030	0.55	6	-	-	-	-
Gibe III HEP	2015	483.7	1,870	3,285	5,348	0.33	7	Gibe III RES	486.5	10,833	258
Gibe IV HEP	2020	565.1	1,472	4,022	6,127	0.48	25	-	-	-	-
Gibe V HEP	2025	565.1	660	1,234	1,899	0.33	26	-	-	-	-
Gojeb HEP		86.0	150	379	559	0.43	27	Gojeb RES	86.4	1,049	141
Halele HEP	2024	80.5	96	247	450	0.53	28	Halele RES	87.3	5,561	737
Karadobi HEP	2021	576.5	1,600	5,084	7,831	0.56	29	Karadobi RES	591.6	18,731	366
Koka HEP	1960	58.6	43	94	133	0.36	8	Koka Lake	63.0	1,169	215
Lower Dabus HEP		168.9	250	430	635	0.29	30	Lower Dabus RES	170.9	1,363	92
Lower Didessa HEP	2034	229.3	550	656	974	0.20	31	Lower Didessa RES	228.7	3,525	178
Maleka Wakana HEP	*2014	24.2	153	325	555	0.41	9	Maleka Wakana RES	25.0	600	278
Neshe HEP	2013	5.8	98	131	245	0.29	10	Neshe RES	6.1	154	290
Renaissance HEP	2017	1,064.3	6,000	10,322	14,684	0.28	11	Renaissance RES	1,543.9	51,600	387
Sor 1 HEP	2014	1.7	5	25	30	0.68	32	-	-	-	-
Sor 2 HEP	2017	9.0	5	30	39	0.88	32	Sor RES	51.3	264	60
Tams HEP		352.6	1,000	4,408	6,044	0.69	33	Tams RES	354.8	4,807	157
Tekeze I HEP	2009	121.3	300	782	1,399	0.53	12	Tekeze I RES	128.8	6,954	625
Tekeze II HEP	2034	205.2	450	1,393	2,713	0.69	34	Tekeze II RES	212.0	6,630	362
Tis Abay I HEP	*2000	54.0	11	-	2	0.02	13	Lake Tana	192.0	9,130	550
Tis Abay II HEP	1993	27.5	68	-	10	0.02	14	Lake Tana	192.0	9,130	550
Upper Dabus HEP	2020	148.6	326	1,142	1,455	0.51	35	Upper Dabus RES	153.9	2,639	198
Upper Mendaya HEP	2023	746.5	1,700	5,552	8,554	0.57	36	Upper Mendaya RES	766.6	10,315	156
Wabi Shebele HEP		98.9	88	477	690	0.90	37	Wabi Shebele RES	100.1	3,333	385
Werabesa HEP	2024	86.8	340	778	1,516	0.51	28	Werabesa RES	86.8	138	18
Yeda 1 HEP	2024	10.6	162	408	627	0.44	38	Yeda RES	11.0	240	253
								Chemoga RES	5.5	265	557
Yeda 2 HEP	2024	10.6	118	299	460	0.45	39	-		-	-
Totals (excluding duplicate reservoir data)			22,517	59,163	89,853					153,958	
Key to status		Existing	Under Construction		Candidate						

(1) If appropriate, AQUARIUS uses head varying productivities based on associated upstream reservoir water levels

(2) Based on AQUARIUS Potential System model and monthly simulation from 01/1965 to 12/2012

(3) AQUARIUS model name(s)

(4) * indicates year of refurbishment

Table 1 : Key Parameters of Existing & Candidate Ethiopian Hydro Projects

The approximate locations of these hydro projects are indicated on Figure 1, and indicate the high levels of potential hydraulic interaction, particularly within the Blue Nile basin, and hence the importance of adequately assessing benefits arising from sequential (cumulative) regulation. A number of reservoirs can be considered as being ‘multi-purpose’ and so competing demands for, say, irrigation releases also needed to be taken into account when estimating generation capabilities.

Previous Ethiopian master planning studies had used software developed by the Canadian firm of ACRES International for estimating the potential performance of hydropower projects (ARSP) and expansion plan simulation/optimisation (SYSIM). However, this software was no longer supported by its developers and EEPCO had experienced problems when applying it to increasingly complex systems. Following discussions, it was agreed that the WASP IV computer program, as supplied by the International Atomic Energy Agency, would be used for the optimisation of generation expansion plans and that Program AQUARIUS, developed by Power & Water Systems Consultants (PWSC) of the UK would be employed for generation system modelling and providing requisite estimates of the capabilities of both existing and candidate hydropower plants. It was further agreed that PWSC’s Expansion Planning SIMulation program (EPSIM) would be used as a complement to WASP IV, and that Siemen’s PSS/E program would be used for planning transmission network extensions.

3.1 Load Forecasts

Sales of electricity supplied from the ICS between 2001 and 2011 increased by an average of 11.4% per annum, and such high rates made it difficult to distinguish between organic growth and underlying seasonal variations. Using a number of statistical techniques, Reference, High and Low global and sectoral demand forecasts were produced for each year until 2037. By then the population of Ethiopia is projected to increase to 149.4 million, an average annual growth rate of 2.6%. The demand forecasts assume high rates of economic growth, especially during the first ten years of the planning period, driven by ambitious plans for developing the industrial and agriculture (irrigation) sectors, and new railway construction.

The average annual growth rates for electricity demand, including exports, were 12.4%, 14.0% and 10.1% for the Reference, High and Low forecasts respectively. Exports to Djibouti, Sudan, Egypt, Kenya and Tanzania were predicted to grow from 1,445 GWh in 2013 to 35,303 GWh by 2037. A distributed load forecasts for 15 load centres was produced for input to the transmission planning process.

3.2 Estimation of Hydro Project Characteristics

A prerequisite for reliable expansion planning is that the characteristics of candidate plants be evaluated on a consistent basis especially when, as in Ethiopia, the hydro projects had been investigated with varying degrees of detail, ranging from river basin through to full feasibility level studies. Given the number of existing and candidate hydro projects to be considered, a major task was the retrieval and collation of large amounts of project related data from available reports and ARSP data sets. Particular concerns were that existing estimates of expected energy production were based on inflow series of different lengths and the application of various definitions of so called ‘firm energy’.

3.2.1 Hydrological Inputs

Consideration of the available flow records led to the selection of the 25 year period from 1961 to 2005 as the basis for estimating the performance of existing and candidate hydroplants. Missing monthly values were estimated using linear multiple regression to create 24 base records, from which were derived the 40 incremental flow series required for the AQUARIUS river system model shown in Figure 2. However, daily records should preferably be used for the calculation of incremental flows due to ‘time of travel’ affects, otherwise negative monthly quantities can result.

Of particular note is the highly seasonal variation of river flows in Ethiopia, with almost 80% of average total flows occurring during the months of July through to October. This uneven distribution has major implications for the volumes of reservoir storage required to ensure regular releases throughout the year. Another important consideration was whether the selected sequence could be considered as representative of long term hydrologic conditions, particularly in view of the catastrophic drought and famine suffered in northern Ethiopia between 1984 and 1987, during which flows were only some 70% of average. Ranking consecutive annual flows suggested that the corresponding four year total is a statistical ‘outlier’ with a low probability of recurrence.

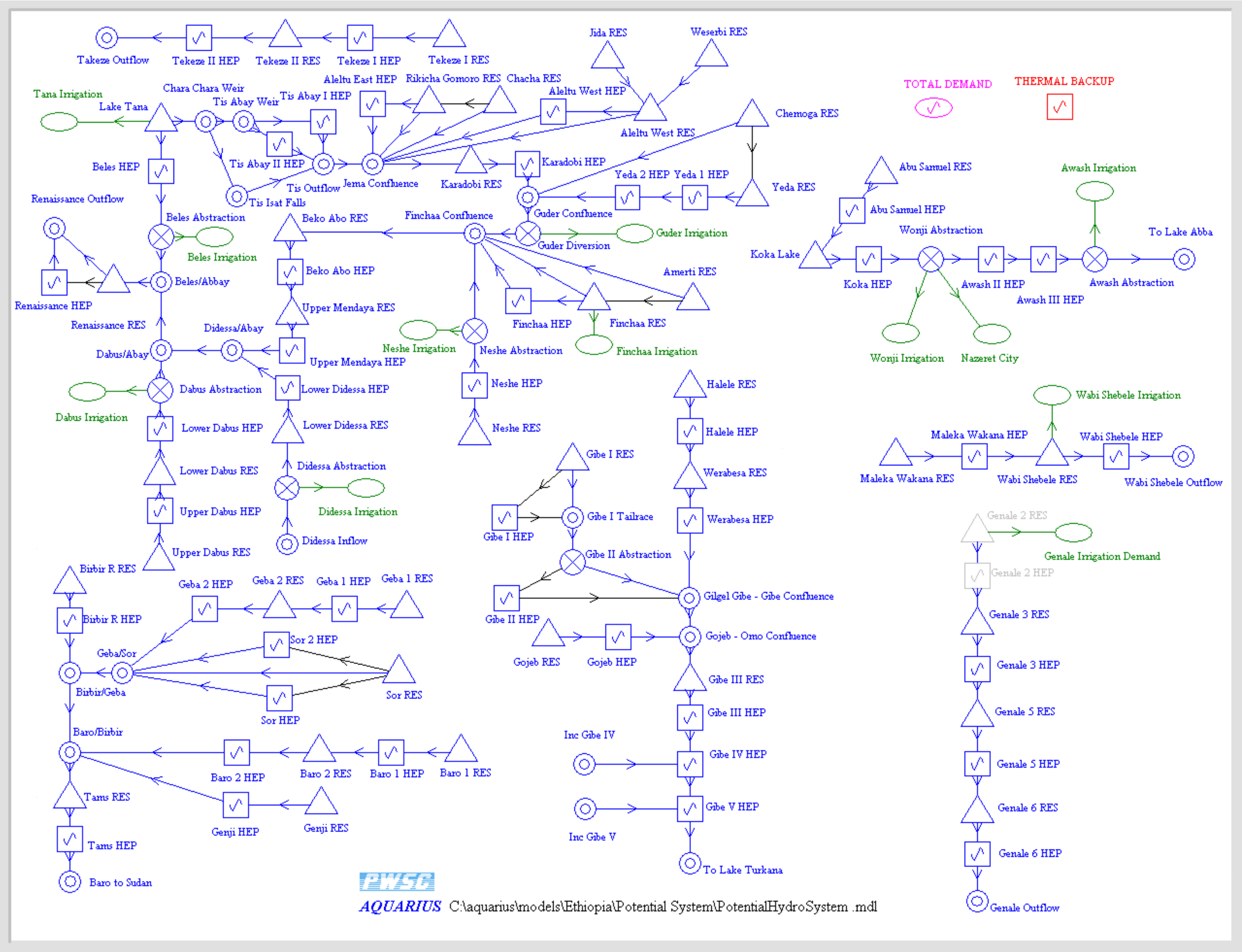

Figure 2 : AQUARIUS Model of Existing & Potential Hydropower Developments in Ethiopia

However, fitting extreme value functions to the historic data suggests that this is not obviously the case, and it was consequently decided that it would be prudent to include the 1984-1987 drought period when assessing hydro plant capabilities. Other hydrological data required for each reservoir were estimates of the calendar month evaporation loss in mm/month. Such losses can be very significant in Ethiopia, especially from Lake Tana which has a large surface area but is relatively shallow.

3.2.2 Other Data Requirements

AQUARIUS models of the Ethiopian water resource and power generation systems also required elevation/volume/surface area relationships for each reservoir and, for each power plant, the specific power outputs in MW per m^3/s as a function of the upstream water level. In addition, and as shown in Figure 2, a number of significant irrigation demands were explicitly modelled and the associated demands specified. A feature of AQUARIUS is that it allows extensive descriptions of the data and its sources to be assigned to each component and stored as part of the model defining input file.

4 Power System Operations Modelling

For each simulation time step AQUARIUS uses Linear Programming (LP) to optimize reservoir releases, river flows and generation plant outputs so that water and electricity demands are met at minimum cost. The objective function includes user specified penalty factors applied to individual water and electricity supply deficits, as well as the satisfaction of minimum river flow requirements and other ‘soft’ constraints. While AQUARIUS and EPSIM are capable of modelling transmission system constraints and losses, these facilities were not used during the study although, for transparency, data on domestic and individual export demands were input separately. A three load block representation of electricity demands was used in both programs to represent peak, mid range and base loads.

AQUARIUS is able to simulate system performance using daily, weekly or calendar monthly time steps, and execution times vary accordingly. Since both the available flow data series and demand forecasts were based on monthly values, and given the complexity of the systems to be analysed, the majority of runs were made using a monthly time step.

4.1 System Operating Policies

When simulating the operation of water resource and power supply systems as complex as those which may develop in Ethiopia over the next decades, the choice of operating policies is of considerable importance. This is not only due to the need to model the benefits of cascade development but also those arising from the conjunctive operation of the hydro systems and other forms of electricity generation, particularly those having significant seasonal variability.

As shown in Table 1, existing and potential reservoirs exhibit a very wide range of characteristics with their active storage, in terms of average inflow, ranging from a few days to well over a year. However, it should be recognised that, given the severity and duration of the multi-annual drought experienced during the mid 1980’s, even such large storage facilities cannot be guaranteed to provide full regulation of inflows.

Similarly, the significant monthly variation in inflows means that considerable storage is required to ensure an even availability of hydroelectric generation during the year. Again, within the existing and potential hydro plants there is a huge variation in installed capacity, ranging from the massive 6,000 MW Grand Renaissance scheme to less than 5 MW.

The system operating policy employed in all AQUARIUS runs executed during the study was to try and keep reservoirs equally full in terms of their active storage, and hence aim to achieve the desirable situations when all reservoirs in the system spill and reach their minimum levels simultaneously. Such a policy can be implemented in AQUARIUS using a global Stored Water Value operating rule with, for example, the ‘cost’ of water held in reservoir storage being assigned a value close to zero when full, rising to just less than the penalty cost of not meeting demands when empty. Thus, at the start of a simulation time step two reservoirs are the same percentage full in terms of active storage, then they will be assigned the same water cost. At the same time, if the cost of stored water is greater than the cost of alternative forms of generation, then the latter will be preferentially dispatched as part of the LP optimisation.

While the global rule described above can be very efficient in managing the long term operation of reservoirs, it can also lead to some undesirable shorter term results. This is particularly true when multi-purpose reservoirs are required to meet irrigation or other localised water demands, including compensation releases. As a result, secondary rules may be required to protect such supplies, and these can be achieved either by increasing their relative stored water values or, preferably, by optimising a set of retention levels below which releases are limited to those necessary to supply water demands only.

4.2 Potential System Model

During the initial phase of the expansion planning process, AQUARIUS was used to estimate the calendar monthly capabilities of existing and potential hydro plants in terms of energy and capacity under different hydrological conditions, it being noted that for some plants there can be significant reductions in hydro capacity with low reservoir levels. At this stage of the study no assumptions could be made as to the characteristics of any non-hydro generation plant that would also be commissioned so, as shown in Figure 2, a single ‘back up thermal’ plant with constant availability was included in the Potential System Model. It can be noted that this model assumes that **all** hydro projects are in operation and hence the full potential effects of sequential regulation were reflected in the energy and capacity capability estimates produced. While this assumption will tend to overestimate the effects of such regulation, in the second phase of the expansion planning process the capabilities were re-estimated on the basis of the actual expected system configuration in a given future year.

Using the AQUARIUS Yield Search facility, the maximum demand that could be met over the 1961–2005 sequence with 100% reliability and a total installed hydro capacity of 22,517 MW was found to be 71,826 GWh/a, giving an average load factor of 0.36. In order to estimate the potential hydro capabilities within a future hydro-thermal system simulation runs were then made with a ‘back up thermal capacity’ equal to the installed capacity less the average output of 8,256 MW.

Unless otherwise constrained, the least cost LP solution will use as much as possible of the lowest valued stored water, and this can result in a relatively uneven distribution of individual reservoir releases and hydro plant outputs over the medium term. Such unevenness was observed in the hydro capabilities initially obtained using the Potential System Model and, while compatible with maximising system outputs, can lead to unrepresentative results when input to expansion plan optimisation algorithms such as WASP. As a result, additional constraints were introduced which set minimum monthly hydro plant target outputs to 20% of their installed capacity. This had the desired effect of smoothing individual plant outputs without impinging on the maximum yield of the system, and the results shown in Table 1correspond to the simulation run made with these constraints imposed.

4.3 Individual Demand Year / System Configuration Models

Following identification of the optimal generation expansion plan obtained from running Program WASP with hydro plant capabilities obtained from the Potential System Model, 13 individual Demand Year / System Configuration AQUARIUS models were constructed. In general, the selected years correspond to those in which there would be a significant change to the system configuration. It should be emphasised that these models represented the complete generation system of existing and scheduled new plants, and thus take specific account of the sequential regulation effects associated with those reservoirs commissioned. Non-hydro plants included wind, solar, biomass, sugar factory producers as well as conventional thermal plants such as single and combined cycle gas turbines, and diesels.

Each individual non-hydro plant was modelled in terms of its operating cost per MWh as well as its calendar monthly availability. The solar, wind and biomass plants, and particularly the sugar factory producers, display significant monthly variations reflecting the seasonal availability of their respective energy sources. Of particular significance is the lack of any generation capability of the sugar factory and biomass plants during the months of June to September, although this would to a considerably degree be offset by the high river flows occurring during the same months.

These models were used to provide updated estimates of individual calendar monthly hydro plant capacity and energy capabilities for use in refining the generation expansion plans derived in the first phase of the planning process. Runs were also made to establish the time that a given configuration could supply the forecast demands as well as whether or not individual plant commissioning dates could safely be delayed.

5 Optimisation of Generation System Expansion Plans

The WASP program was used to develop generation system expansion plans over the 25 year planning horizon. A 12 season simulation was employed with capacity and energy outputs for each hydro plant corresponding to 'firm' and 'average' hydrological conditions taken from the AQUARIUS runs. The WASP optimisation algorithm has limitations in that candidate hydro plants are successively selected from two lists. Hydro candidates were therefore ranked in terms of their overall investment cost per kWh of average energy production. Engineering, Procurement and Construction (EPC) costs for the 27 hydro plant candidates shown in Table 1 were estimated based on those contained in available reports, and differential inflation rates applied to the component parts of the works. Capital costs included Interest During Construction (IDC), environmental costs and substation and specific transmission costs, and a 90% standard conversion factor was applied to local costs.

Existing thermal plant use imported light fuel oil, but potentially there are indigenous gas, oil and coal resources that could be developed, and imports could include oil, gas, coal and uranium. Screening curves were produced to compare the overall cost per kWh at different plant load factors of thermal plant candidates, and resulted in the coal-fired and nuclear plant being excluded from further consideration. Separate modelling of candidate solar and wind power plants at selected sites was undertaken so as to provide the requisite cost and availability data. The resulting generic non-hydro candidate plant units considered were: 100 MW geothermal, 300 MW wind power, 300 MW solar, 140 MW gas turbines, 420 MW combined cycle gas fired turbines, and 70 MW diesels. The fuels selected for the candidate plant included imported light and heavy fuel oil, together with a gas development/import option from 2025 with conversion from oil as appropriate.

The analyses were carried in 2012 monetary terms, with a 'real' (i.e. inflation removed) discount rate of 10% and a Cost Of Unserved Energy (COUE) of 1.0 US$/kWh adopted for the Reference Case scenario. Sensitivity runs were carried out for the low and high load demand forecasts, 8% and 12% discount rates and a COUE of 0.5 US$/kWh. Since the existing and future Ethiopian generation systems are likely to be hydro dominated, energy rather than capacity availability is the critical planning parameter. It can also be noted that the costs of unserved energy form an explicit component of the objective function which WASP seeks to minimise, and hence balance investment and operating costs against the 'economic' costs of failing to fully meet forecast electricity demands. As a result, it would seem incorrect if 'firm' hydro plant energies were estimated as corresponding to less than 100% reliability in terms of the available historic flow sequences.

With the performance characteristics of existing and candidate plants based on the AQUARIUS Potential System Model, WASP was used to determine the corresponding least cost solution based on the total discounted investment, operating and unserved energy costs. Variations in the maximum seasonal generation from solar, wind, sugar and biomass plants were simulated by specifying additional maintenance days and adjusting their capacities. The earliest dates when new plant could become available, e.g. as a result of minimum construction times, and resource constraints limiting the number of candidate units that could be commissioned in any given year were significant.

The resulting initial expansion plan provided data for construction of the individual AQUARIUS Demand Year / System Configuration Models which were then used to refine the capacity and energy availabilities ascribed to hydro plants in service in a particular year, taking account of sequential flow regulation and the availabilities of installed non-hydro plant. The effects of delaying the introduction of various hydro plants was tested by fixing the hydro project commissioning dates and allowing WASP to optimise the introduction of non-hydro plant, and hence identify the refined plan with the minimum net present value. Some complications arose from the fact that, whereas AQUARIUS simulates on a daily, weekly or calendar monthly basis WASP uses seasons of equal length. Spreadsheets were developed to combine AQUARIUS derived hydro plant data for input to WASP and for post-processing of WASP results, and EPSIM was employed to confirm the WASP results and to undertake sensitivity tests.

Table 2 details the recommended Generation Expansion Plan for the Reference Load Forecast, and Figure 3 compares the monthly energy demand with the firm and average energy availabilities. Wind, solar and diesel generation makes an early contribution and there is a large hydro-power development up to 2025, especially when the already committed hydro plants are included. Combined cycle plant is scheduled 2025 onwards when imported or domestic gas is assumed to become available. Geothermal plant would be installed up to the specified limits, reaching 5,000 MW by 2027. Plans for the location of non-hydro plant were developed for input to the transmission planning process.

Non-Hydro Generating Plant Units in Service							Hydro Projects to be Commissioned
Unit Type	Geothermal	Wind	Solar PV	GT (Gas)	CCGT (Gas)	Diesel	
Capacity	100 MW	300 MW	300 MW	140 MW	420 MW	70 MW	
2012							
2013							
2014							
2015							
2016		1	1				
2017		2	1				Sor 2
2018	2	3	1				
2019	3	3	1			6	
2020	5	3	1			6	Geba 1 & 2, Genale 6, Gibe IV, Upper Dabus
2021	7	3	1			6	Karadobi
2022	9	3	1			6	Beko Abo
2023	9	3	1			6	Upper Mandaya, Birbir R
2024	9	3	1			6	Werabesa, Halele, Yeda 1 & 2, Baro 1 & 2, Genji
2025	12	3	1	1		6	Genale 5, Gibe V
2026	16	3	1	1		6	
2027	16	3	1	1		6	
2028	21	3	1	2		6	
2029	23	3	1	2	2	6	
2030	25	4	1	3	3	6	
2031	28	4	1	3	4	6	
2032	31	5	1	3	5	6	
2033	34	5	1	4	6	6	
2034	37	5	1	4	6	6	Takeze II, Lower Didessa
2035	42	5	1	5	6	6	
2036	46	5	1	5	7	6	
2037	50	5	1	5	8	6	

Table 2 : Reference Case Generation Expansion Plan

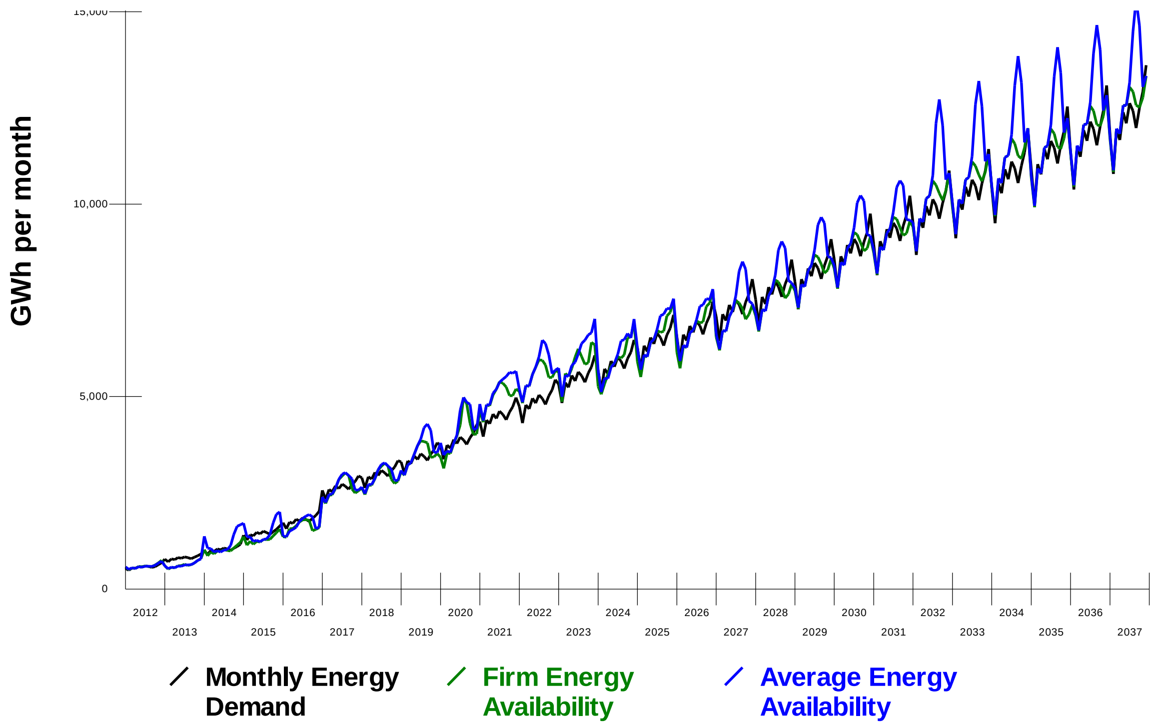

Figure 3 : Reference Case Generation Expansion Plan
Monthly Energy Demands and Energy Availabilities (GWh/month)

6 Optimisation of Associated Transmission Systems

The transmission system in 2013, its short term development to 2020 and that necessary to support the long term Reference Generation Expansion Plan to 2037 were studied in detail using the power systems analysis program PSS/E. The analyses undertaken included load flow, fault level, transient stability and switching studies. A database of over 550 transmission projects, including lines substations and reactive compensation was compiled.

In 2013 the system included 400 kV, 230 kV, and 132 kV transmission lines together with sub-transmission at 66 kV and 45 kV. At the time of the study a large number of transmission projects were under construction and committed, including the introduction of transmission at 500 kV to connect Grand Renaissance to Addis Ababa and to Sudan. A whole life economic comparison to 2050 including costs of investment, losses, and maintenance was carried out comparing the development of the rest of the EHV grid at 400 kV or 500 kV. Due to the need to maintain an N-1 level of security of supply in the future, adopting 500 kV would not lead to a reduction in the number of circuits, and the present value analysis showed that the reduced cost of the losses at 500 kV was not sufficient to offset the increased investment costs. An additional whole life cost analysis separately considered the connection of the major hydro plants of Upper Mendaya, Beko Abo and Karadobi to the grid, and confirmed that connection at 400 kV would be more economic than 500 kV or 765 kV. The main system development was therefore based on 400 kV. Over the period 2013 to 2037, a total of 1301 km of 500kV, 5,682 km of 400 kV, 8,630 km of 230 kV and 6,068 km of 132kV transmission circuits was planned.

7 Conclusions

The WASP program for ‘optimising’ generation expansion plans was originally developed in the 1970’s and, although it continues to be accepted by lending agencies as a sound basis for evaluating investments in electricity generation, is known to have a number of limitations. These include the need to externally rank candidate hydro plants; no facilities for taking account of project interdependencies; and a single demand area representation of electricity demands. Within the Ethiopian Master Plan study, considerable efforts were made to take account of interactions between all types of generation plant by constructing models of future system configurations and simulating their performance when required to satisfy projected demands. The results were used to successively refine the original WASP derived expansion plan and take account of the benefits that should accrue from sequential regulation and the need to accommodate non-hydro generation plants having significantly different seasonal availabilities.

Derivation of the Power System Expansion Plan required the retrieval and collation of large amounts of technical and economic data, and the extensive assistance provided by the EEPCO planning team is gratefully acknowledged. This data included that associated with 27 candidate hydro projects studied at different levels of detail. To provide consistent estimates of the capabilities of these and existing hydro plants, and the benefits associated with sequential regulation, sophisticated models of the existing and potential national water resource system and power generation systems were constructed and some 40 monthly incremental flow series covering the years 1961-2005 established. The installed computer software and data input sets should enable EEPCO (now Ethiopian Electric Power – EEP) to update the generation and transmission expansion plans on a regular, preferably annual, basis so as to reflect changing demand forecasts, plant construction schedules and other data changes. However, while considerable time was spent training EEPCO staff, it is suggested that such projects should cater for a degree of on-going technical support relating to the use of increasingly sophisticated models and analysis.

The growth and planning of multinational power pools which promote the interchange of electrical energy significantly increases the complexity associated with power system expansion planning. For example, justification for developing large scale hydro projects may well depend on the terms of potential export agreements and associated tariffs, while in other cases the costs of new generation plant may need to be balanced against those of transmission system reinforcement or the availability of imports. Such considerations suggest the need for integrated generation and transmission system planning which also takes explicit account of project interdependencies. In an effort to overcome such perceived limitations, a (continuous) Linear Programming optimisation module has been developed for use in conjunction with Program EPSIM which can simultaneously optimise integrated generation and transmission expansion plans while taking account of multiple electricity demand areas, transmission capacity constraints and losses, mutually exclusive and mutually dependent generation and transmission line projects, hydro project energy capabilities as a function of upstream developments and weighted operating costs under ‘average’ and ‘firm’ hydro energy conditions. Initial experience indicates the feasibility and practicality of such an approach for problems involving several thousand objective function variables and constraints.

Timothy Wyatt graduated from Edinburgh University in 1969 with an Honours degree in Civil Engineering. After 4 years researching the application of simulation and mathematical programming techniques to water resource systems, he spent 6 years in Latin America as a hydrologist and water resources engineer working on Electricity Masterplan studies for Guatemala and Peru, before being appointed as project leader for a power system expansion study in Uruguay. He has subsequently analysed hydro-thermal power systems in Sri Lanka, Cameroon, Brazil, Turkey, Tanzania and Ethiopia, and developed the AQUARIUS computer program for simulating and optimising the long and short-term operation of integrated water resource, water supply and power supply systems, and Program EPSIM for simulating and optimising the expansion of integrated power supply systems. He is the Managing Director of Power & Water Systems Consultants Ltd. (PWSC), which he co-founded in 1983, and has authored a number of papers on operating policy optimisation and development planning.

Andrew Pearce graduated with First Class Honours in Engineering Science from Oxford University in 1973. After a graduate apprenticeship he gained 7 years consultancy experience as an Electrical Engineer in the UK and the Middle East in project engineering and power systems analysis. Subsequently he specialised in load forecasting and least cost generation and transmission planning, gaining world-wide experience in Africa, Eastern Europe and the NIS countries, the Caribbean and in the Near and Far East. He also worked on rural electrification studies, including distribution from the electrified lightning shield wires of transmission lines. Andrew was Technical Director of Energy Strategic Consulting at Parsons Brinckerhoff, and his work has included project management and analysis for major Masterplan Studies in Jordan, Kurdistan, and Iraq. He was PB’s Project Manager for the Ethiopian Electricity Masterplan Study carried out for the Ethiopian Electric Power Company (EEPCO). He is now an independent consultant.

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