ENTRO

EASTERN NILE POWER TRADE PROGRAM STUDY

AfDB

PRE-FEASIBILITY STUDY OF DAL HYDROPOWER PROJECT, SUDAN

FINAL REPORT

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with participation of :

- EPS (Egypt)
- Tropics (Ethiopia)
- YAM (Sudan)

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LIST OF ABBREVIATIONS/ACRONYMS

A	Ampere (Unit of electric current)
AC	Alternating Current
ARF	Area Reduction Factor
B/C ratio	Benefit/Cost ratio
ºC	Degrees Celsius (centigrade)
CCGT	Combined Cycle Gas Turbine
CFRD	Concrete Faced Rockfill Dam
cm	centimetre
CN	Curve Number
CV	Curve of Variation
D	Diameter
DC	Direct Current
DSM	Demand Side Management
EIA	Environmental Impact Assessment
EIRR	Economic Internal Rate of Return
EELPA	Ethiopian Electric Light and Power Authority
EEPCO	Ethiopian Electric Power Corporation
EFY	Ethiopian Fiscal (or Financial) Year
EMA	Ethiopian Mapping Authority
ENCOM	Eastern Nile Council of Ministers
ENSAP	Eastern Nile Subsidiary Action Programme
ETB	Ethiopian Birr (national currency unit)
ETC	Ethiopian Telecommunications Corporation
EV1	Extreme Value type 1
FIRR	Financial Internal Rate of Return
FSL	Full Supply Level
FWL	Flood Water Level
GPS	Global Positioning System
GWh	Gigawatt-hour (equals 1000 MWh)
ha	Hectare (unit of area)
HD	Hydrology Department
HEC1	Hydrology simulation model
HFO	Heavy Fuel Oil
HH	Household
HPP	Hydro Power Project
HV	High Voltage
HVAC	High Voltage Alternating Current
HVDC	High Voltage Direct Current
Hz	Unit of frequency (Hertz)
ICB	International Competitive Bidding

ICOLD	International Committee on Large Dams
ICS	Interconnected System
IDC	Interest During Construction
IDEN	Integrated Development of the Eastern Nile
IEA	Initial Environmental Assessment
ITCZ	Inter-Tropical Convergence Zone
km	kilometre
kV	Kilovolt (1000 volts)
kVA	Kilovolt-ampere
kWh	Kilowatt-hour
kW	Kilowatt
LAN	Local Area Network
LCGEP	Least Cost Generation Expansion Plan
LF	Load factor (Ratio of average load to peak load)
LLF	Loss load factor (Ratio of peak loss to average loss)
LFO	Light Fuel Oil
LS	Lump sum
LV	Low Voltage
LWRL	Lowest Regulated Water Level
m	metre
MDE	Maximum Design Earthquake
mm	millimetre
m/s	metres per second
m^3/s	cubic metres per second (unit of flow)
MAF	Mean Annual Flood
MAP	Mean Annual Precipitation
masl	metres above sea level
MCC	Motor Control Centres
MOL	Minimum Operating Level
MoWR	Ministry of Water Resources (Ethiopia)
MSHP	Medium Scale Hydropower Plants Study
MPa	Mega-Pascal (Unit of pressure (stress))
MPP	Multipurpose project
MUSD	Million United States Dollars
MVA	Megavolt-ampere
MVAr	Megavolt Ampere reactive rating
MV	Medium Voltage
MW	Megawatt
MWh	Megawatt-hour
N	Newton (= 1 kg x acceleration of gravity) (unit of force)
NA	Not Applicable
NELSAP	Nile Equatorial Lakes Subsidiary Action Programme
NBI	Nile Basin Initiative
NMSA	National Meteorological Services Agency

NPV	Net Present Value
O&M	Operation and Maintenance
OPGW	Optical Fibre Ground Wire
Pa	Pascal (= 1 N/m^2)
PF	Ratio of active power on apparent power (Power factor)
PMF	Probable Maximum Flood
PMP	Probable Maximum Precipitation
PLC	Power Line Carrier
PSS	Power System Stabilizer
PV	Present Value
R	Resistance (electric)
RCC	Roller Compacted Concrete
RFP	Request for Proposal
RHO	Regional Hydrological Office
rpm	revolutions per minute
RQD	Rock Quality Designation
s (sec)	second
SC	Series Compensation (transmission)
SCF	Standard Conversion Factor
SCS	Self Contained System
SIL	Surge Impedance Load
SPT	Standard Penetration Test
STD	Sexually Transmitted Disease
SV	Static Voltage controller
SVS	Static Var Compensator
TCSC	Thyristor Controlled Series Compensator
TOR	Terms of Reference
TWh	Terawatt-hour
UCB	Unit Control Board
UCS	Uniaxial Compressive Strength
UAB	Unit Auxiliary Board
UG	Underground
US	Upstream
USc	United States Cent
USD	United States Dollar
USSCS	United States Soil Conservation Service
UTM	Universal Transverse Mercator grid (maps)
V	Volt
VA	Volt-ampere
VAr	Volt-ampere reactive
W	Watt
Wh	Watt-hour
WMO	World Meteorological Organisation

E.1. EXECUTIVE SUMMARY

E.1.1 PROJECT AREA

The Dal project site is located on the Nile some 280 km downstream of Dongola and immediately upstream of Lake Nubia / Lake Nasser formed by the Aswan High Dam. (Figure E.1). The catchment area for the Dal project comprises the entire Blue Nile and White Nile river basins together with the Main Nile downstream of Khartoum.

The headwaters of the Blue Nile are in the mountains surrounding Lake Tana, the largest tributary of which is the Gilgel Abay. Lake Tana, at an elevation of approximately EL. 1785 m provides significant regulation of the natural river flow in the upper reaches of the Blue Nile. The Blue Nile flows generally within a deeply incised gorge which has a relatively gentle gradient falling some 630 m over 500 km from an elevation of El.1030 m at Kessie bridge to El. 500 m at the Sudan Border.

The White Nile originates at the outlet of Lake Albert in Uganda and includes flow from the Victoria Nile, which in turn is fed by Lake Victoria. The White Nile flows generally northwards through the Sudd to join the Blue Nile at Khartoum. Downstream of the confluence of the Blue Nile and White Nile rivers the Nile River flows northwards to Egypt and the Mediterranean Sea. The mean annual flow of the Nile at Dal is estimated as some 2668 m^3/s.

E.1.2 DEVELOPMENT OPTIONS FOR THE NILE IN SUDAN

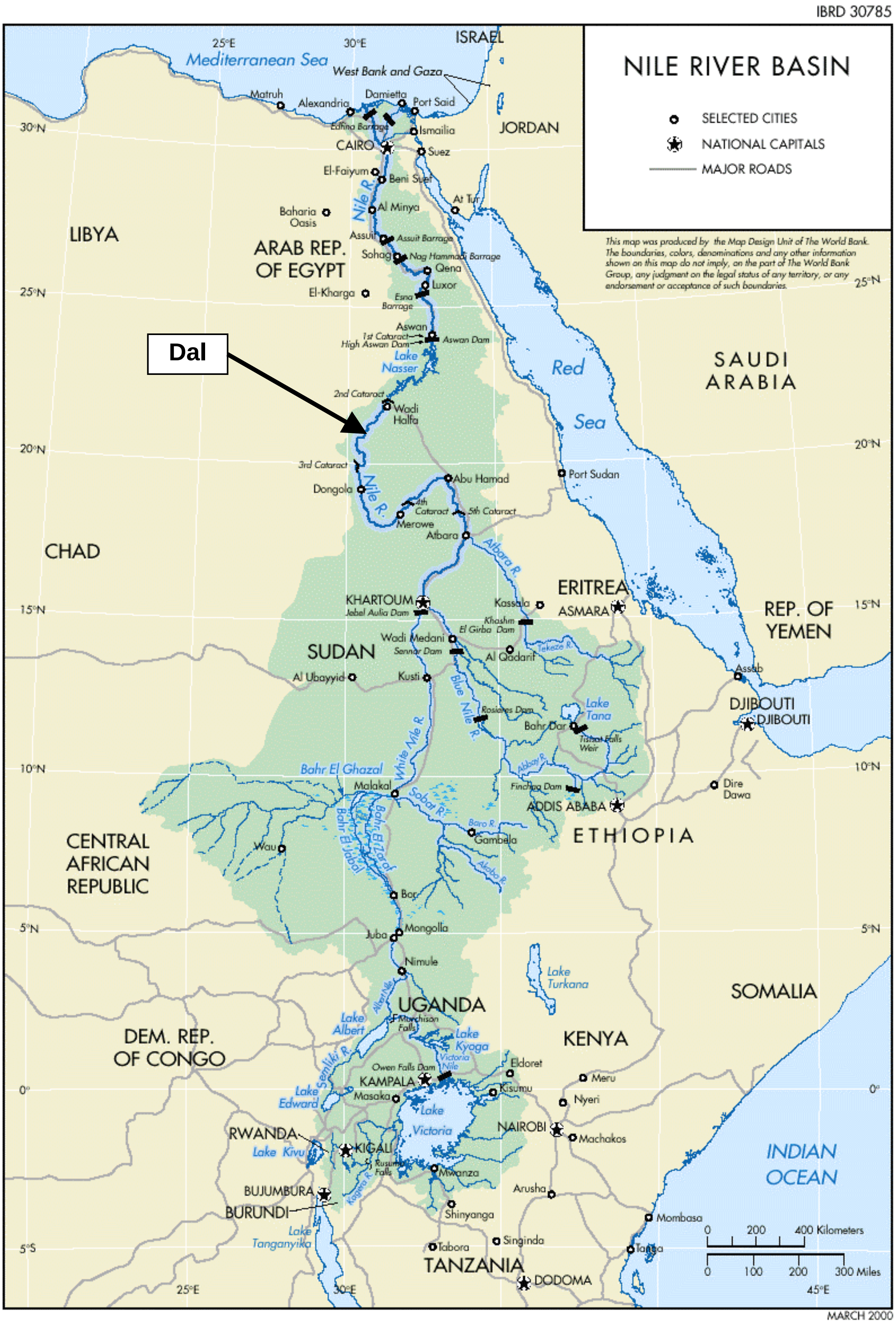
The Nile Waters Study was completed in 1979 and identified potential hydropower development sites on the main stream of the Nile in Sudan as well as on each of the tributary valleys of the Blue and White Nile as listed in Table E.1. These projects have subsequently been re-evaluated in successive power system planning studies carried out for the National Electricity Corporation in 1993 and 2006.

Table E.1 : Characteristics of Hydropower Projects on the Nile

Site	Gross Head (m)	Full Supply Level (m)	Reservoir Area (km^2)	Installed Capacity (MW)	Average Energy Output (GWh/year)
Dal (Low)	20.5	201	300	340	1943
Dal (High)	37.5	218	990	780	3150
Kagbar	17	218	300	108	851
Kagbar (Alt.)	17	218	300	340	1421
Merowe	55	300	700	1250	5500
Dagash	16	323	250	285	1520
Shereik	20	343	250	315	2000
Sabaloka	11.5	374	140	120	520

The Merowe project commenced construction in 2003 and is now nearing completion.

Figure E.1 : Location of Hydropower Project Sites



The characteristics of the Dal project as proposed in the Nile Waters Study are shown in Table E.2. The Dal project was planned as a 600 MW development with 6 turbine-generator units each of 100 MW. A 400 kV transmission line was planned to evacuate the power over the 670 km distance to Khartoum.

Table E.2 : Characteristics of Dal Hydropower Project (Nile Waters Study, 1979)

Length of Dam (m)	5200
Maximum Height (m)	74
Retention Level (m)	218
Reservoir Area (km^2)	1000
Installed Capacity (MW)	600
Rated Head (m)	38
Average Annual Energy (GWh/Yr)	3500

E.1.3 INITIAL REVIEW OF PROJECT

At the outset of this study an initial review of the Dal project was undertaken based on information from available mapping and field reconnaissance. The primary objective of the review was to assess the previous studies and to identify constraints to development of the Dal site.

The principal constraints to the development of the Dal site comprise low topography on the west bank of the river and the number of affected persons living and depending on the river and in particular on its annual flood regime in an area which does not benefit from rainfall.

The review concluded that the site was potentially suitable for development of a dam up to some 20 m in height with a full supply level of up to El. 201 m. This development has been characterised in previous studies as the “Low Dal” option. In contrast, the “High Dal” option with a dam some 40 metres in height and with full supply level of El. 218 m was considered to have very high social and environmental impacts.

As a result of this initial review the study of the Dal project described in this report has been confined to the “Low Dal” option. The development of the Low Dal project is compatible with development of the Kagbar project upstream and does not have any impact on other developments upstream along the Nile.

E.1.4 RESERVOIR CHARACTERISTICS

The reservoir characteristics of the Dal reservoir have been determined from existing reports based on cross-sections that have been surveyed at 5 km intervals along the Nile and are presented in Table E.3 and Figs. E.2 and E.3.

Table E.3 : Dal Reservoir Elevation Area Volume Relationship

Elevation (m)	Area (km^2)	Volume ($m^3 \times 10^6$)
180	14	45
183	24	100
187	52	246
190	87	456
193	133	780
197	195	1,420
200	277	2,120
205	421	3,876
210	614	6,436
215	836	10,031
220	1,117	14,842
230	3,177	39,172

Figure E.2 : Dal Reservoir Elevation Area Relationship

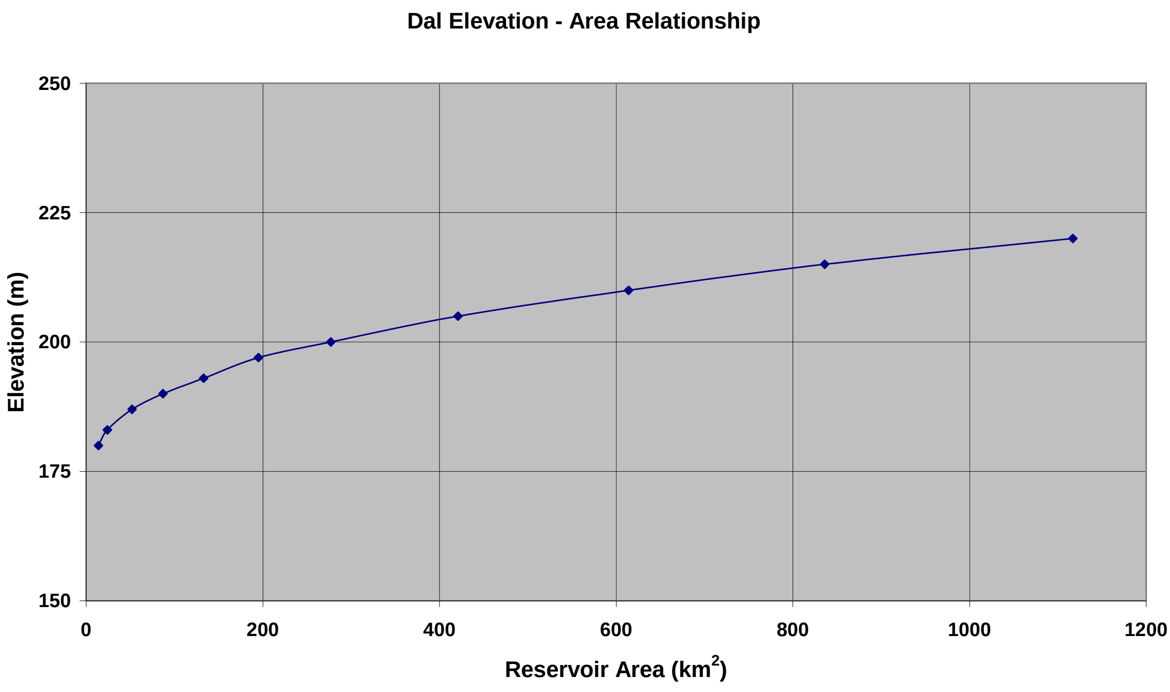
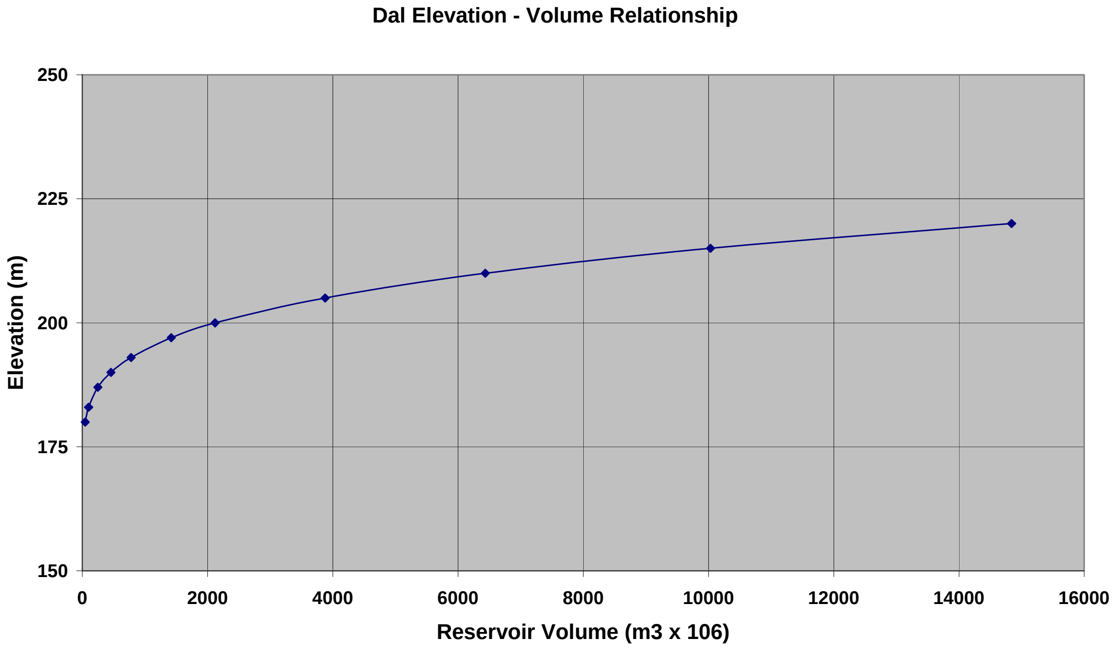


Figure E.3 : Dal Reservoir Elevation Volume Relationship



E.1.5 HYDROLOGY

The Dal site is located some 280 km downstream of the Dongola hydrometric station and some 120 km upstream of the former Wadi Halfa hydrometric station. There are no intervening catchments. Accordingly the time series for flow at Dongola has been adopted directly for the Dal site. Recorded average monthly flows for Dongola are given in Table E.4.

Table E.4 : Summary of Average Discharge for Dongola (1890-1995) (m^3/s)

Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
1335	1053	847	864	812	837	1967	6982	7930	4979	2611	1694	2668

The flow sequence for the period 1954 – 2003 has been adopted for reservoir simulation studies in common with the other projects, Mandaya and Border, in Ethiopia.

E.1.6 FLOOD STUDIES

Flood estimates for design of the Dal spillway to ensure safe passage of flood flows and design of river diversion works are shown in Table E.5, below.

Table E.5 : Frequency Analysis of Flood Flows (m^3/s) for Nile at Dongola

Return Period (Years)	Method	
	LP3	Gumbel
10000		21,670
1000		18,240
500		17,200
100	13,790	14,800
50	13,080	13,760
20	12,100	12,370
10	11,260	11,300
5	10,340	10,190

The construction of the Merowe project upstream of Dal will alter the flood regime in the Nile at Dongola and further downstream at Dal. Depending on the exact mode of operation a significant attenuation of flood magnitude in the Nile at Dongola and Dal can be anticipated associated with the routing of floods through the Merowe reservoir, particularly with the lower return period events. A design capacity of 10,000 m^3/s has been adopted for the river diversion works during construction approximately equivalent to the 1 in 20 year flood.

For reasons of dam safety, it will be necessary to ensure that flood releases from Merowe can pass the Dal dam safely under all foreseeable circumstances. Accordingly, a spillway capacity of 20,000 m^3/s has been adopted for the Dal site, similar to the design capacity of the Merowe spillway.

E.1.7 SEDIMENT

Recent measurements over the period 2001 to 2003 suggest that the mean annual suspended sediment discharge in the Main Nile amounts to some 140 Mt/yr.

It is noted that this figure is significantly lower than recent estimates for average sediment discharge in the Abbay (Blue Nile) at Kessie in Ethiopia of 220 Mt/yr produced as part of the present study, based on sediment concentration measurements carried out at the Kessie hydrometric station in 2004.

A sediment balance for the Nile River was prepared as part of the Cooperative Regional Assessment (CRA). The sediment discharge entering Karadobi has been assumed as 92 Mt/yr compared to a current estimate for sediment discharge at Kessie (slightly upstream of Karadobi), based on 2004 data of 220 Mt/yr in this study.

There is a high level of uncertainty regarding many of the estimates involved in deriving a sediment balance for the Nile given that many of the individual components of the balance are highly variable from year to year and that measurements are infrequent and imprecise. Some data is now more than 40 years old whilst it is anticipated that sediment discharge will have increased over this period due to pressures of population, agriculture and deforestation.

Although the overall balance of sediment along the Nile downstream of Merowe is therefore uncertain, the average sediment discharge at the Dal site following construction of the Merowe project can probably be expected to lie within the range 75Mt to 100 Mt, depending on the effectiveness of the sediment flushing regime at Merowe. Much of this sediment will be very fine grained and will have a lower trapping efficiency in Dal than would be the case without Merowe upstream. A trapping efficiency of 55 % has been estimated for Dal based on Brune's relationship for primarily fine grained and colloidal particles and assuming that sediment flushing at Dal would not take place. Under these circumstances it is anticipated that sediment deposition in the Dal reservoir will be some 40 - 55 Mt/year, or some 30 – 40 Mm^3/year.

E.1.8 RESERVOIR AND POWER SIMULATION

Computer simulations have been carried out to estimate the energy characteristics of the potential alternative scheme configurations of the Dal project. The simulations have been performed employing a program named RAPSO that has been developed over a long period of years to represent seasonal and annual operation of any combination of hydroelectric schemes. The RAPSO model was set up and calibrated for the recent National Electricity Corporation (NEC) long-term power system planning study to represent all existing and potential schemes in the Sudanese Nile system. Results are summarised in tabular and graphical forms below.

The average energy outputs together with some other key indicators that have been calculated for the alternative installations of the Low Dal scheme, both without and with the Mandaya project upstream, are presented in Table E.6. Operation without Mandaya over the 3 hydrological years 2001-03 is illustrated graphically in Figure E.4.

The flow commanded by Mandaya, which that scheme could regulate to a considerable extent, is some 44 per cent of the inflow to Dal. Operation with Mandaya over the 3 hydrological years 2001-03 is illustrated graphically in Figure E.5. The reductions in the spill peak with Mandaya upstream can be seen by comparing Figure E.4 with Figure E.5.

Table E.6 : Energy Outputs for Dal Project

Option	Full Supply Level (m)	Installed Capacity (MW)	Energy Output (GWh/year)
Low Dal	**201**	**340**	**1,944**
Low Dal	**201**	**400**	**2,160**
Low Dal with Mandaya	**201**	**340**	**2,088**
Low Dal with Mandaya	**201**	**400**	**2,304**

Figure E.4 : Operation of Low Dal with 8x50 MW

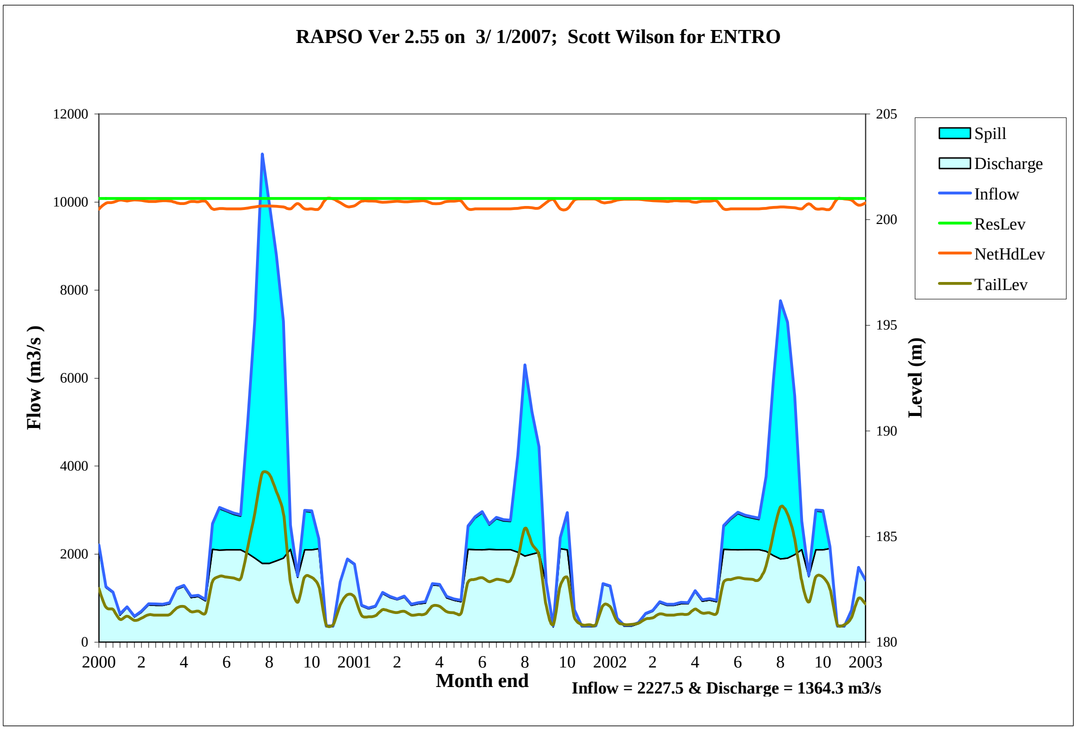
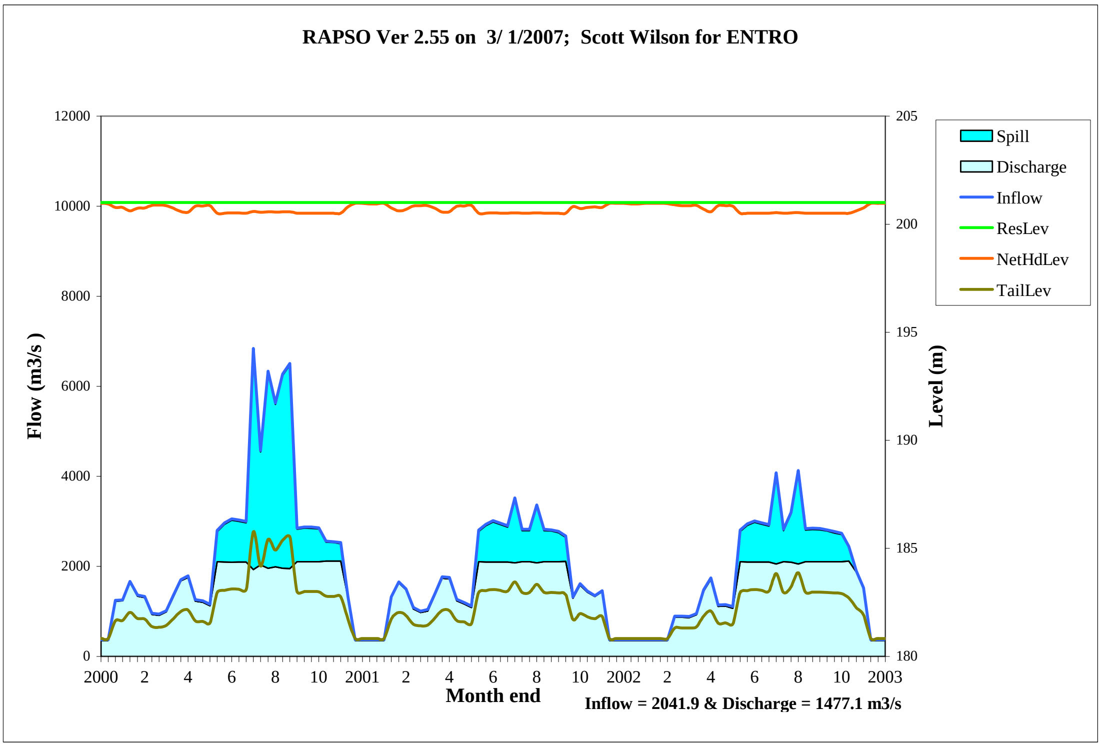


Figure E.5 : Operation of Low Dal with 8x50 MW and Mandaya 800 m FSL



E.1.8.1 Downstream Impacts in Egypt

The Low Dal and Kajbar projects are essentially run-of-river projects with very small storage reservoirs. As such there are no significant impacts associated with reservoir filling or operation and these have not been specifically studied.

E.1.9 GEOLOGY

Dal dam site is situated at the northern end of a south/north stretch of the Nile. In the Dal stretch the river is following a north striking foliation trend and possibly a geological contact parallel to the foliation. The Dal cataract is carved out of resistant granite and gneissic granite rock.

The Nile appears to have migrated from west to east at Dal. The slopes to the west of the river are relatively flat and planed-off, with sparse hills of granite protruding from out of desert sands. On old elevated terrace of the Nile is found on the west side of the river, elevated levees and scatters of alluvial pebbles on top of windblown sand, indicate that the alluvial terrace is at least 1 km wide.

The landscape to the east of the Nile is very rocky, and steeper than that seen on the west side. This side of the Nile has only a narrow recent alluvial terrace, and it appears that the rocky outcrops are being undercut and steepened by gradual eastward migration of the river. Wadis on the east bank correspond to geological weaknesses that have been eroded away (dykes and faults) during “geological time”.

Geological mapping at the site confirmed the existence of four broad geological formations; namely the Massive Grey Granite, Sheared Granitoid Gneiss, Pink Sheared Syenite/Diorite Granitoid Gneiss, and Biotite Schist / Amphibolite Gneiss. All these rocks are Precambrian in age, and they are all intruded by pegmatite, felsite, and basic dykes of indeterminate age. Fault zones were not seen in the field. Pegmatite and acidic dykes are ubiquitous across the entire mapped area.

A striking feature of both potential centre lines for the Dal dam is the rock slope that forms each right flank, and the very narrow alluvial terrace at the base of each rock slope, but the depth of these narrow terraces is unknown. Both centrelines have a single deep active river channel on the eastern side of the river section. The depth of alluvium below this channel is unknown. Both centrelines have rocky islands in the centre and west side of the active channel, and outcrops are quite frequent, this gives the favourable impression of shallow alluvium and good foundation conditions. However it is possible that the outcrops and islands are buried pinnacles separated by deep trenches filled with alluvium. The depth of alluvium at the dam site is crucial to the cost effectiveness of the Dal dam site and this will need to be investigated in detail during feasibility studies.

The Dal Site falls on the stable intra-cratonic plate. The nearest earthquake hot-spot to the Dal site, is the Red Sea rift trench, but this is 800 km from Dal. Clearly the Dal site lies in a zone of low to very low risk of seismic hazard.

E.1.10 PROPOSED DESIGN OF DAL DAM AND POWER STATION

The valley profile at the Dal site allows development of the dam, diversion works and power station as surface structures within the river channel. The site is suitable for dams up to some 20 - 40 metres in height but appears to be limited by the elevation of the left bank where an extensive embankment may be required as well as saddle dams in the reservoir rim and by a low saddle on the East bank at an elevation of approximately El. 224 m.

The Dal dam at the selected site will have a crest length of some 1,400 m and will have a maximum height of some 30 metres. Having regard to the site topography, geology and availability of materials at the Dal site, together with the substantial flows which must be accommodated both during construction and in the spillway facilities it is considered that an CFR dam is the most appropriate choice of dam type and offers advantages over alternative dam types such as clay-core rockfill or concrete dams.

The width of the valley at the river level allows development of a river diversion arrangement based passing flow through the western channel while construction of the spillway and power station structures is carried out within the Eastern channel protected by temporary cofferdams.

The spillway will comprise 12 radial gates each 10 m wide by 12.5 m high, with a total discharge capacity of 20,000 m^3/s with the reservoir at full supply level. The spillway gates have been sized to be capable of discharging the 1 in 10,000 year flood released from the Merowe dam upstream.

The power waterway system will comprise a reinforced concrete intake structure incorporating unitised intake gates and associated control equipment for each of the eight turbine-generator units. The intake structure will also be equipped with trash screens and trash raking mechanism, and slots to allow bulkhead gates to be deployed for gate, waterway and unit maintenance. The intakes will be integral with the powerhouse substructure and the concrete semi-spiral arrangement of the Kaplan turbine units.

The powerhouse will be a surface type structure of reinforced concrete and structural steel, construction, integral with the dam structure and located in the Eastern river channel. The powerhouse accommodates a loading/service bay, one bay for each of the 8 Kaplan turbine units, control block and offices. The tailrace of the Dal scheme will discharge directly into the existing river channel.

Each turbine will be directly connected to a vertical shaft synchronous generator. The rated output of each turbine will be 50 MW assuming a design net head of 18 m. The synchronous speed of the unit has been selected at 100 rpm.

E.1.11 TRANSMISSION SYSTEM

It is envisaged that the transmission system would connect the Dal power station to the existing Sudan grid at Dongola.

E.1.12 ACCESS ROADS AND BRIDGES

Improvement of the existing road on the East bank from Dongola to the Dal site will be required to accommodate construction traffic and heavy loads. A temporary crossing will be required across the Nile to permit construction access to the West bank.

E.1.13 COST ESTIMATE

The cost of the Dal project has been estimated as USD 1,113.2 million inclusive of environmental mitigation measures. A breakdown of the project cost is given in Table E.7.

Table E.7 : Dal Project Cost Estimate

Item	Cost (Million USD)
Environmental Mitigation	220.0
Access Roads and Infrastructure	48.5
Reservoir Clearance	16.5
Civil Works	
Diversion works	17.2
CFR Dam	98.6
Spillway	53.6
Powerhouse and tailrace	125.9
Switchyard and Buildings	5.7
Civil contingencies	45.1
Mechanical and Electrical Plant	345.5
Sub-total	976.6
Engineering and Construction Management	97.6
Owners Administration	39.1
OVERAL TOTAL	1,113.2

E.1.14 CONSTRUCTION PROGRAMME

The Dal project will take some 6 years to construct. Final installation and commissioning of all 8 turbine-generator is anticipated to require 7.5 years from commencement of construction.

Assuming that feasibility studies are carried out over the period 2007 – 2008, it is considered that the project could be completed by the end of year 2016.

E.1.15 ENVIRONMENTAL IMPACT

The Dal project will inundate an area of some 300 km^2 consisting mainly of desert with palm trees and agricultural areas along the river margin. The river margin has locally dense population in towns and villages along the river and the displaced population has been estimated at approximately 40,000 people.

E.1.16 CO_2 EMISSION SAVINGS

The Dal project will provide carbon emission savings of some 68 million tonnes of CO_2 over the assumed 50 year project life compared to equivalent thermal generation based on a 50%/50% gas-fired CCGT / coal fired thermal generation mix.

E.1.17 GENERATION PLANNING AND ECONOMIC APPRAISAL

The Dal hydropower project is a relatively high cost source of energy when compared to the major projects on the Abbay (Blue Nile) River in Ethiopia such as the Mandaya, Border and Karadobi projects. As such, the Dal project does not form part of the regional development plan. However, in advance of the implementation of the regional interconnector there Dal project may be considered as part of a national power development strategy within Sudan since it offers a lower cost source of energy than the thermal power alternatives within Sudan.

E.1.18 KEY PROJECT CHARACTERISTICS

Power and Energy			
	Installed Capacity	400 MW	
	Annual energy generation	Average	2,160 GWh/yr
	Plant factor	62%	
Hydrological data			
	Mean annual flow	2668 m^3/s	
Reservoir data			
	Full supply level	201 m	
	Minimum operating level	199 m	
	Operating range	2 m	
	Gross storage	2.47 x 10^9 m^3	
	Live storage	0.35 x 10^9 m^3	
	Surface area at FSL	300 km^2	
	Length of reservoir at FSL	160 km	
Dam			
	Type	Concrete faced rockfill (CFR)	
	Maximum height	30 m	
	Crest elevation	204 m	
	Crest length	1400 m	
	Dam volume	2,300,000 m^3	
Spillway			
	Type	Gated barrage	
	Design capacity	20,000 m^3/s	
	Elevation of spillway invert	172 m	
	No.of gate bays	12	
	Size of gates (W x H)	10 m x 12 m	

Power Intake		
	Sill elevation	170.5 m
	No. of intakes	8
Powerhouse		
	Type	Surface
	Overall length	211 m
	Overall width	20 m
	Generator floor level	180 m
	Access / loading bay level	190 m
Turbines		
	Type	Kaplan, vertical axis
	No.	8
	Speed	100 rpm
	Design net head	18 m
	Setting	170.5 m
Generator		
	Type	Vertical synchronous
	Size	62 MVA
Transmission		
	Route	Dal to Dongola
	Length	240 km
	Voltage	220 kV ac
	Type	Double circuit

1. INTRODUCTION

1.1 BACKGROUND OF THE NILE BASIN INITIATIVE

The Nile Basin encompasses ten countries: Burundi, Democratic Republic of Congo, Egypt, Eritrea, Ethiopia, Kenya, Rwanda, Sudan, Tanzania, and Uganda. In 1997, the Nile riparian countries initiated dialogue on a long term Cooperative Framework and in 1999 the Council of Ministers of Water Affairs of the Nile Basin States (Nile-COM) formally launched the Nile Basin Initiative (NBI)-an interim financing mechanism for development of regional projects. The NBI is represented by its executive arm, the Nile Secretariat (Nile-SEC) based in Entebbe, Uganda.

Nile-COM has approved a basin-wide integrated program to jointly pursue sustainable development and management of the Nile waters for promoting economic growth, eradicating poverty, and reversing environmental degradation. The program is called the Shared Vision Program (SVP) and includes seven projects, namely (1) Trans-boundary Environmental Action (2) Regional Power Trade (3) Efficient Water Use for Agriculture Production (4) Water Resource Planning and Management (5) Confidence Building and Stakeholder Participation (6) Applied Training and (7) Socio-Economic Development and Benefit Sharing.

In parallel, Nile-COM also approved action-oriented sub-basin programs, namely the Nile Equatorial Lakes Subsidiary Action Program (NELSAP) and the Eastern Nile Subsidiary Action Program (ENSAP). NELSAP includes Burundi, Democratic Republic of Congo, Kenya, Rwanda, Egypt, Sudan, Tanzania, and Uganda while ENSAP includes Ethiopia, Egypt, and Sudan. Eritrea is participating in ENSAP as an observer. NELSAP and ENSAP are meant to shift focus from planning to action on the ground through investment in actual development projects. Such projects cover irrigation and drainage development, hydropower development and power transfer networks & trade, watershed management, sustainable development of lakes & wetland systems, river regulation, flood & drought management, etc.

Nile-COM then formed the Nile Equatorial Lakes Council of Ministers (NELCOM) and the Eastern Nile Council of Ministers (ENCOM) to oversee the activities of NELSAP and ENSAP, respectively. NELCOM and ENCOM are assisted in their activities by teams of technical specialists from the respective member countries.

1.2 ORIGIN OF THE STUDY

Following the establishment of ENCOM, Ethiopia, Egypt, and Sudan have jointly adopted a strategy to develop, utilize, and manage water resources of the Eastern Nile basin in an integrated, equitable, and sustainable manner.

In defining the cooperative development paradigm, the countries identified sixty-four potential regional projects. Out of these seven priority projects, known as the Integrated Development of the Eastern Nile (IDEN) were selected. These are:

- Ethiopia-Sudan Interconnection Project,
- Eastern Nile Power Trade Investment Program Study

- Eastern Nile Multi-sector Planning Model,
- Baro-Akobo Multipurpose Hydro Power Project,
- Flood Preparedness and Early Warning,
- Irrigation & Drainage Development, and
- Watershed Management.

In order to prepare, monitor, and supervise the implementation of the IDEN, ENCOM established the Eastern Nile Technical Regional Office (ENTRO) in Addis Ababa.

In January 2002 on behalf of ENCOM, the Minister of Water Resources of the Government of Ethiopia (ENCOM Chairman) requested the African Development Bank to fund the Eastern Nile Power Trade Program Study. The African Development Bank included the funding of the Study in the Lending Program for the year 2003. The Terms of Reference (TOR) have been prepared by the Bank Mission, which visited Ethiopia, Egypt, and Sudan in July 2003. The TOR has been based on deliberations of the consultation workshop attended by donors and the EN country representatives held in Addis Ababa in July 2003 and documents collected from the field.

The Study area encompasses the Eastern Nile region, which includes Egypt, Ethiopia, and Sudan. The countries, along with other riparian states, share the waters of River Nile.

1.3 THE CONSULTANTS

Following an international competitive bidding procedure Electricité de France (EDF), in association with Scott Wilson of United Kingdom (SW) were appointed by ENTRO to carry out the Eastern Nile Power Trade Program Study.

EDF and Scott Wilson are supported and assisted by sub-Consultants in Ethiopia, Egypt and Sudan as follows:

- Tropics Consulting Engineers plc, Ethiopia,
- Electric Power Systems Eng. Co. (EPS), Egypt,
- YAM Consultancy and Development Co. Ltd, Sudan.

The Contract for the Eastern Nile Power Trade Study was signed on 26th June 2006 and the assignment commenced on 20th October 2006.

1.4 SCOPE OF THE SERVICES

The study will be carried out in two parts:

Phase 1: Co-operative Regional Assessment of Power Trade Opportunities

Phase 2: Feasibility Study of the Power Interconnection involving Ethiopia, Egypt and Sudan.

Phase 1 of the study includes the following key activities:

- Development of a Strategy for Power Trade
- Inception and Market Assessment
- Supply and Delivery Option Analysis
- Pre-feasibility Studies of Hydropower Projects
- Investment Planning and Modelling
- Regional Investment Programme

1.5 PRE-FEASIBILITY STUDIES OF HYDROPOWER PROJECTS

In order to widen the list of supply options that will be used in investment planning, the Terms of Reference require that the co-operative regional assessment of power trade opportunities shall include three pre-feasibility studies for hydropower sites that have been studied at reconnaissance level and agreed upon by the three EN countries. The sites are:

- Mandaya, Ethiopia
- Border, Ethiopia (close to the border with Sudan) and
- Dal-1 in Sudan (close to border with Egypt).

The location of each of the three sites is shown on Figure 1.1.

The pre-feasibility studies are required to be completed within 9 months of the commencement of the project, by 20th July 2007.

In the pre-feasibility Studies, multiple uses of the Nile waters (hydropower, irrigation, and flood control) and the associated regional benefits and costs will be considered. In particular, the benefits of potential irrigation, reduction in silt, and flood control in the hydropower sites, agreeable to the EN countries, will be clearly identified. These benefits will serve as useful comparative indicators for the countries in making decisions related to these projects. The Environmental and Social Impact assessment will be carried out in accordance with the Bank guidelines. Further, in accordance with the Bank Group's Involuntary Resettlement Policy (January 2003), resettlement and compensation plan will be prepared for affected population.

This report presents the Pre-feasibility Study of the Dal Hydropower Project in Sudan. The environmental and social impact assessment of the Dal hydropower project is presented in a separate report.

Figure 1.1 : Location of Hydropower Project Sites

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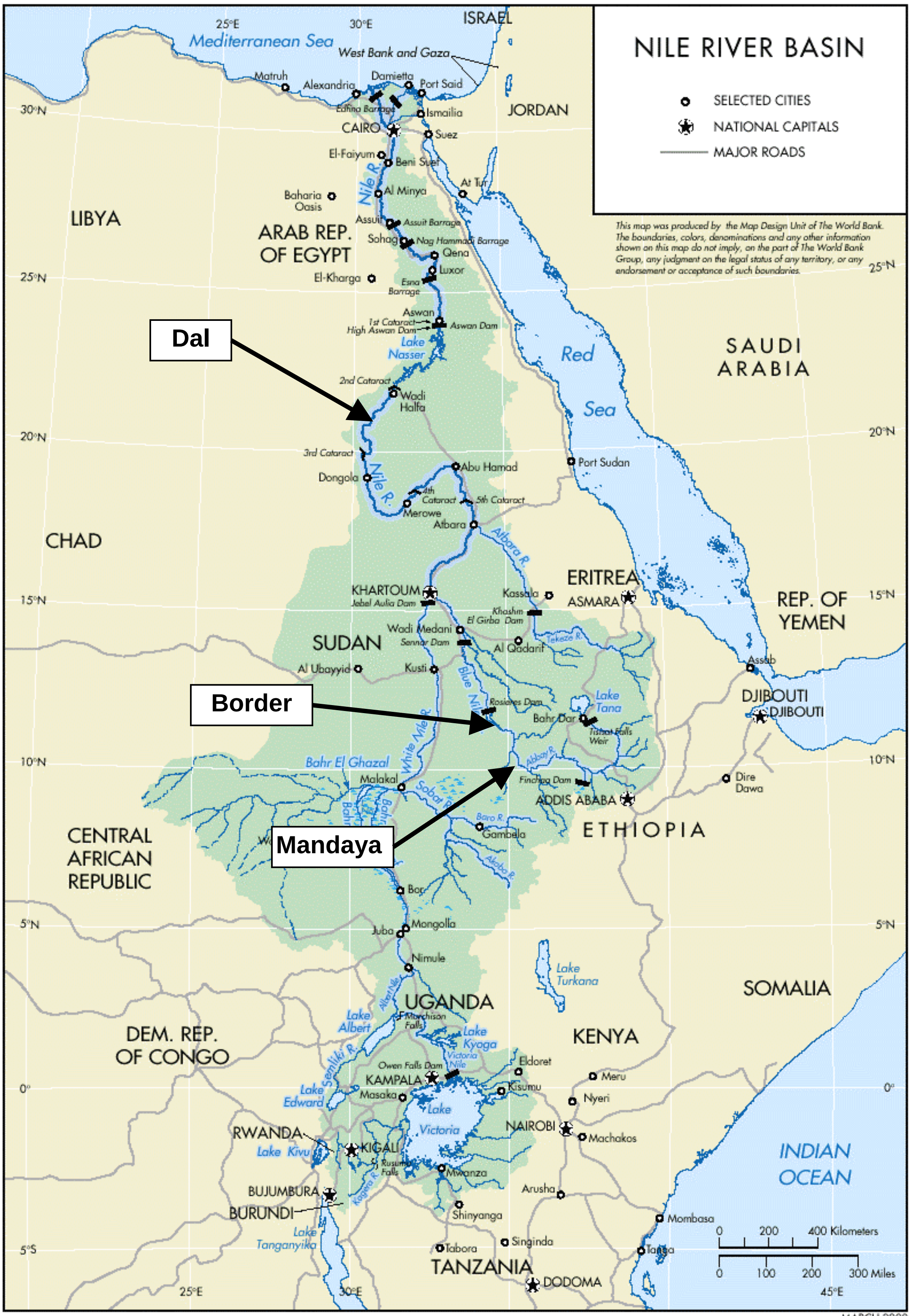


2. BACKGROUND TO THE DAL PROJECT

2.1 PROJECT AREA

The Dal project site is located on the Nile some 280 km downstream of Dongola and immediately upstream of Lake Nubia / Lake Nasser formed by the Aswan High Dam. The catchment area for the Dal project comprises the entire Blue Nile and White Nile river basins together with the Main Nile downstream of Khartoum.

The headwaters of the Blue Nile are in the mountains surrounding Lake Tana, the largest tributary of which is the Gilgel Abay. Lake Tana, at an elevation of approximately EL. 1785 m provides significant regulation of the natural river flow in the upper reaches of the Blue Nile. Much of the upper part of the basin comprises the highland plateau with elevation generally exceeding 2000 m. The plateau exhibits extensive level areas with intensive agriculture divided by incised valleys. Mountain peaks rise to over 4000 m in the North. The Blue Nile flows generally within a deeply incised gorge which has a relatively gentle gradient falling some 630 m over 500 km from an elevation of El.1030 m at Kessie bridge to El. 500 m at the Sudan Border. The course of the Blue Nile describes a broad arc exiting Lake Tana to flow in a south-easterly direction before exhibiting a wide turn to flow generally westwards as far as the Didessa confluence and thereafter northwards in the direction of the Sudan border. Thereafter the river flows generally northwards towards the confluence with the White Nile at Khartoum.

The White Nile originates at the outlet of Lake Albert in Uganda and includes flow from the Victoria Nile which in turn is fed by Lake Victoria. The White Nile flows generally northwards through the Sudd to join the Blue Nile at Khartoum. Downstream of the confluence of the Blue Nile and White Nile rivers the Nile River flows northwards to Egypt and the Mediterranean Sea. The mean annual flow of the Nile at Dal is estimated as some 2668 m^3/s.

Within the reach of the Nile between Khartoum and Aswan a series of rapids are found at various locations at which erosion resistant rocks of the Basement Complex cut across the river. These rapids have historically been known as “Cataracts” and are numbered sequentially. The 1st Cataract is located at Aswan while the 6th Cataract is located close to Abu Dom, some 80 km North of Khartoum. The 3rd Cataract is located some 60 km downstream of Dongola. Other un-numbered cataracts are also found including that at Dal some 200 km downstream of Dongola.

Each Cataract provides a potential site for hydropower development taking advantage of the more resistant rock formations to ensure good foundation conditions.

2.2 PREVIOUS STUDIES

2.2.1 The Nile Basin

The Nile Basin Volumes I to XI comprises a series of reports prepared by different authors over the period 1932 to 1978 and published by the Government Press, Cairo.

Additional supplementary reports have also been prepared extending up to the present summarising hydrological records.

Reports of relevance to the present study include Volume IX (1959) *The Hydrology of the Blue Nile and Atbara and of the Main Nile to Aswan* and Volume X (1966) *The Major Nile Projects*.

2.2.2 Nile Waters Study (1979)

The Nile Waters Study was completed in 1979 by a consortium of consultants comprising Coyne et Bellier, Sir Alexander Gibb, Hunting Technical Services and Sir M. Macdonald and Partners. The study identified potential hydropower development sites on the main stream of the Nile as well as on each of the tributary valleys of the Blue and White Nile.

The Nile Waters Study considered hydropower developments at both the 3rd Cataract and at Dal cataract. Development at the 3rd cataract was dismissed as any impoundment at this location would have involved widespread flooding of agricultural land in the Kerma – Dongola region. Consideration had been given in past studies to dam sites at Dal cataract and at Semna Gorge although the Semna Gorge site, which lies some 100km downstream of Dal is now within the reach flooded by Lake Nasser / Lake Nubia following construction of the Aswan High dam.

The reservoir impounded by a high dam at Dal would flood the towns of Abri and Delgo and would extend upstream beyond the 3rd Cataract. Backwater studies carried out as part of the Nile Waters Study indicated that with a retention level of El. 218 m would create, on average, an annual flood which would have the same effect at Argo as the natural flood. The town of Dongola itself would be unaffected.

Tailwater levels for the Dal dam would be controlled by the water level in Lake Nubia which has a top retention level of El. 182 m, but as the upper 6 m is reserved for flood storage the tailwater level at Dal would be affected only rarely and a tailwater level of El. 176.0 m was adopted for planning purposes.

Little detailed topographical information was available for the Dal site and a cross-section was adopted from previous surveys at a chainage of 155 km upstream from Wadi Halfa. The site lies at the upstream extremity of the cataract where va number of islands are located within the river channel. These offer the potential to divert flow to one side or the other of the islands while constructing the power station, spillway and dam embankment works.

The principal characteristics of the Dal project as proposed in the Nile Waters Study are summarised in Table 2.1, below:

Table 2.1 : Characteristics of Dal Hydropower Project (Nile Waters Study, 1979)

Length of Dam (m)	5200
Maximum Height (m)	74
Retention Level (m)	218
Reservoir Area (km^2)	1000
Installed Capacity (MW)	600
Rated Head (m)	38
Average Annual Energy (GWh/Yr)	3500

The project was planned as a 600 MW development with 6 turbine-generator units each of 100 MW. A 400 kV transmission line was planned to evacuate the power over the 670 km distance to Khartoum.

2.2.3 Sudan Long-Term Generation Planning Study (Acres, 1993)

The Long Term Power System Planning Study carried out by Acres considered various potential thermal and hydropower generation projects throughout Sudan. Specific sites identified with significance to the present study included potential dam and hydropower sites on the main Nile as shown in Table 2.1, below (in order commencing at Dal and moving upstream from Egypt - Sudan Border towards Khartoum):

Table 2.2 : Characteristics of Hydropower Projects on the Nile (Acres 1993)

Site	Gross Head (m)	Full Supply Level (m)	Reservoir Area (km^2)	Installed Capacity (MW)	Average Energy Output (GWh/year)
Dal (Low)	20.5	201	300	340	
Dal (High)	37.5	218	990	780	3150
Kagbar	17	218	300	300	
Merowe	40	293	425	1000	3960
Shirri	22	307	145	400	
Mograt	14	307	30	240	1360
Dagash	16	323	250	285	1520
Shereik	20	343	250	350	2000
Sabaloka	11.5	374	140	120	520

Two options were considered for development at the Dal site designated Alternative I with full supply level of El. 218 m as proposed in the Nile Waters Study and Alternative II, a lower option with full supply level of EL. 201 m.

The site adopted was similar to that described in the Nile Waters Study but with minor changes to the project layout and centreline alignment. The High Dal project (Alt. I) was planned to have 10 x 78 MW Kaplan turbine units with total capacity of 780 MW.

The Low Dal project (Alt. II) was envisaged to have an installed capacity of 340 MW utilising 8 Bulb turbines each of 42.5 MW capacity. The spillway would comprise 12 bays each with gates and provision for maintenance using stoplogs to isolate each bay. Fill dams would be required on each abutment.

2.2.4 Long Term Power System Planning Study (PB Power, 2006)

The Long Term Power System Planning Study considered many of the same group of hydropower projects as the Acres (1993) study described above except that the Merowe project was already under construction by the time of completion of the study in 2006. The projects considered comprised:

Table 2.3 : Characteristics of Hydropower Projects on the Nile (PB Power 2006)

Site	Gross Head (m)	Full Supply Level (m)	Reservoir Area (km^2)	Installed Capacity (MW)	Average Energy Output (GWh/year)
Dal (Low)	20.5	201	300	340	
Dal (High)	37.5	218	990	780	3150
Kagbar	17	218	300	108	
Merowe	55	300	700	1250	5500
Dagash	16	323	250	285	1520
Shereik	20	343	250	315	2000
Sabaloka	11.5	374	140	120	520

Of the above list only the Shereiq, Merowe and Kajbar projects were initially selected for consideration in detail in the study whist the other projects were later added at the request of the National Electricity Corporation. The arrangements for the Dal project were unchanged from those proposed by Acres (1993) with the exception of the cost estimate which was updated using the Merowe unit rates as a guide. The estimated cost of the Dal project options were as follows:

Table 2.4 : Dal Hydropower Project – Cost Estimate (PB Power, 2006)

Item	Capital Cost (US$ Million)	
	Dal - High	Dal - Low
Civil Works	709.0	369.1
Mechanical works	147.7	139.9
Electrical Works	172.0	156.3
Total Direct Costs	1028.7	665.3
Contingency Civil works (15%)	141.8	73.8
Contingency E + M (10%)	32.0	29.6
Total Contingency	173.8	103.4
Construction Cost	1202.4	768.7
Engineering (8%)	96.2	61.5
Owners Costs (2%)	24.0	15.4
Total	1322.7	845.6

2.3 INITIAL REVIEW OF PROJECT

At the outset of the study an initial review of the Dal project was undertaken based on information from available mapping and field reconnaissance. The primary objective of the review was to assess the previous studies and to identify constraints to development of the Dal site.

The principal constraints to the development of the Dal site comprise low topography on the west bank of the river and the number of affected persons living and depending on the river and in particular on its annual flood regime in an area which does not benefit from rainfall.

The review concluded that the site was potentially suitable for development of a dam up to some 20 m in height with a full supply level of up to El. 201 m. This development has been characterised in previous studies as the "Low Dal" option. In contrast, the "High Dal" option with a dam some 40 metres in height and with full supply level of El. 218 m was considered to have very high social and environmental impacts.

As a result of this initial review the study of the Dal project described in this report has been confined to the "Low Dal" option.

The development of the Low Dal project is compatible with development of the Kagbar project upstream and does not have any impact on other developments upstream along the Nile.

2.4 DAL RESERVOIR CHARACTERISTICS

The reservoir characteristics of the Dal reservoir have been determined from existing reports based on cross-sections that have been surveyed at 5 km intervals along the Nile and are presented in Table 2.5 and Figs. 2.1 and 2.2.

Table 2.5 : Dal Reservoir Elevation Area Volume Relationship

Elevation (m)	Area (km^2)	Volume ($m^3 \times 10^6$)
180	14	45
183	24	100
187	52	246
190	87	456
193	133	780
197	195	1,420
200	277	2,120
205	421	3,876
210	614	6,436
215	836	10,031
220	1,117	14,842
230	3,177	39,172

Figure 2.1 : Dal Reservoir Elevation Area Relationship

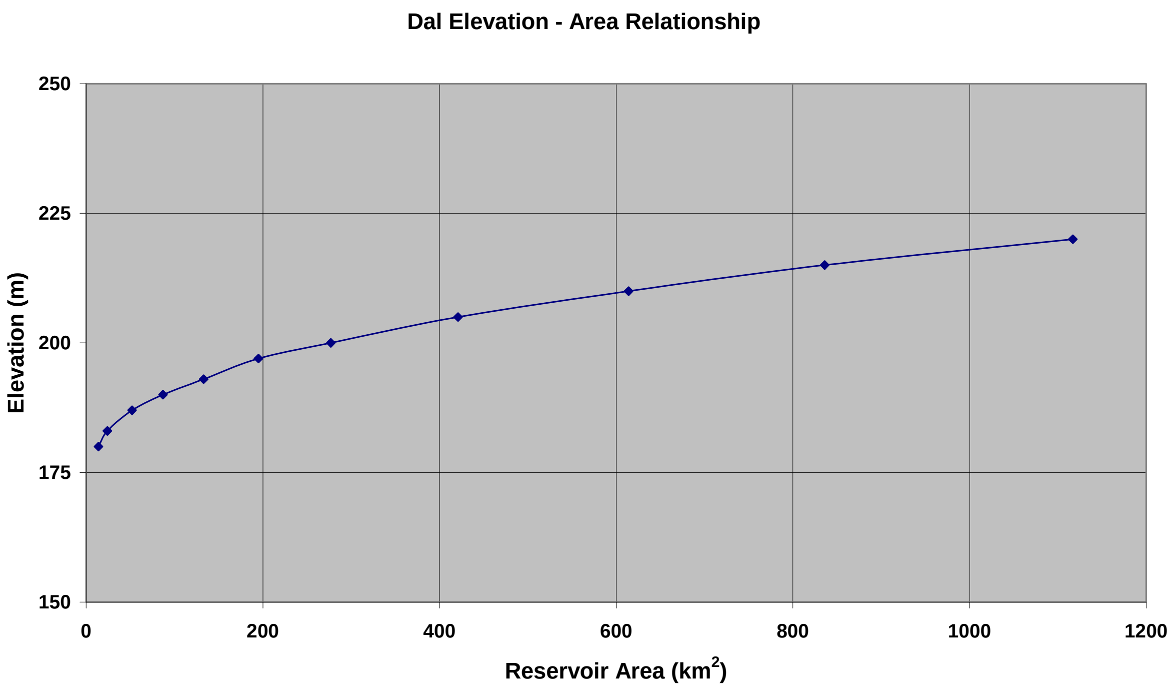
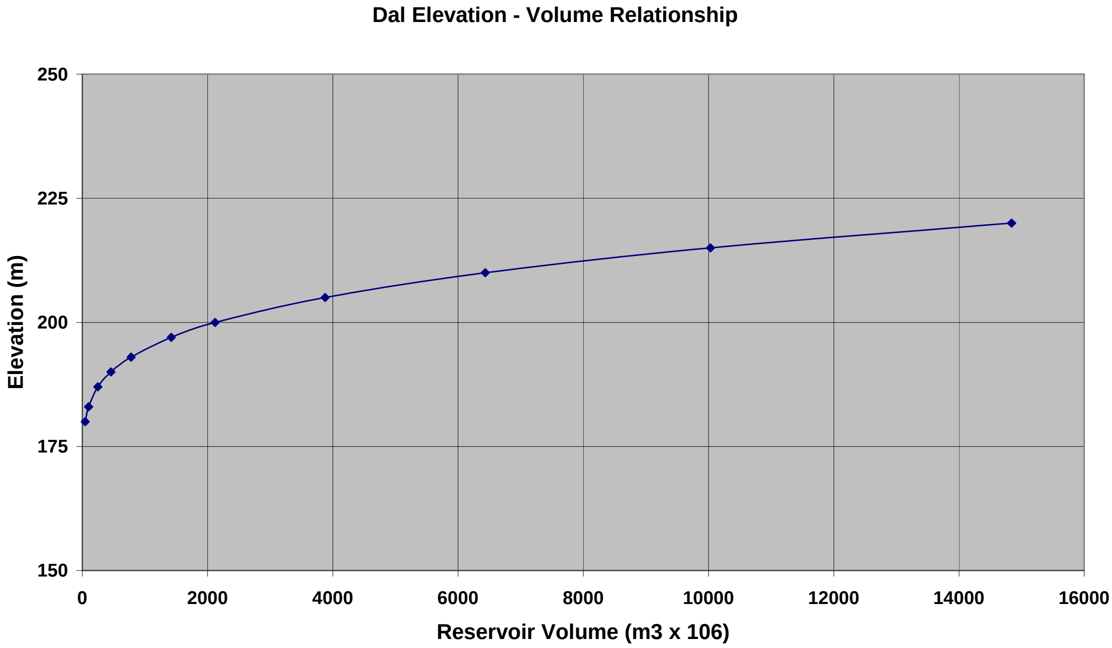


Figure 2.2 : Dal Reservoir Elevation Volume Relationship



2.5 REFERENCES

1. Nile Basin Volumes I to XI, Government Press, Cairo.
2. Nile Waters Study, Coyne et Bellier, Sir Alexander Gibb, Hunting Technical Services and Sir M. Macdonald and Partners, 1979
3. Sudan Long-Term Generation Planning Study, Acres, 1993.
4. Building Of Electricity Sector Database & Long-Term Power System Planning Study, Interim Report No. 3 : The Data Book, PB Power 2006.

3. HYDROLOGY

3.1 INTRODUCTION

The Dal project site is located on the Main Nile some 280 km downstream of Dongola and immediately upstream of Lake Nubia / Lake Nasser formed by the Aswan High Dam.

The headwaters of the Blue Nile are in the mountains surrounding Lake Tana, the largest tributary of which is the Gilgel Abay. Lake Tana, at an elevation of approximately EL. 1785 m provides significant regulation of the natural river flow in the upper reaches of the Blue Nile. Much of the upper part of the basin comprises the highland plateau with elevation generally exceeding 2000 m. The plateau exhibits extensive level areas with intensive agriculture divided by incised valleys. Mountain peaks rise to over 4000 m in the North. The Blue Nile flows generally within a deeply incised gorge which has a relatively gentle gradient falling some 630 m over 500 km from an elevation of El.1030 m at Kessie bridge to El. 500 m at the Sudan Border. The course of the Blue Nile describes a broad arc exiting Lake Tana to flow in a south-easterly direction before exhibiting a wide turn to flow generally westwards as far as the Didessa confluence and thereafter northwards in the direction of the Sudan border. Thereafter the river flows generally northwards towards the confluence with the White Nile at Khartoum.

The White Nile originates at the outlet of Lake Albert in Uganda and includes flow from the Victoria Nile which in turn is fed by Lake Victoria. The White Nile flows generally northwards through the Sudd to join the Blue Nile at Khartoum.

Downstream of the confluence of the Blue Nile and White Nile rivers the Main Nile River flows northwards through the Sabaloka gorge and is joined some 325 km north by its final tributary, the Atbara which drains the northern portion of the Ethiopia highlands and part of Eritrea. The Atbara is dry for much of the year but contributes flashy flood inflows and considerable sediment loads.

Downstream of the Atbara confluence the Main Nile flows in a series of wide loops within a broad gently sloping basin extending some 582,368 km^2 or 48.7 percent of the Eastern Nile Basin within the Sudan. To the east are the Red Sea Hills with a number of khories that very rarely reach the Nile. In the west the land rises gently towards the Darfur plateau. A large wadi – the Wadi el Milk intermittently drains this area but fails to reach the Nile. The mean annual flow of the Nile at Dal is estimated as 84.1 Mm^3/year (equivalent to 2,668 m^3/s).

Within the reach of the Nile between Khartoum and Aswan a series of rapids are found at various locations at which erosion resistant rocks of the Basement Complex cut across the river. These rapids have historically been known as “Cataracts” and are numbered sequentially. The 1st Cataract is located at Aswan while the 6th Cataract is located close to Abu Dom, some 80 km North of Khartoum. The 3rd Cataract is located some 60 km downstream of Dongola. Other un-numbered cataracts are also found including that at Dal some 200 km downstream of Dongola. Each Cataract provides a potential site for hydropower development taking advantage of the more resistant rock formations to ensure good foundation conditions.

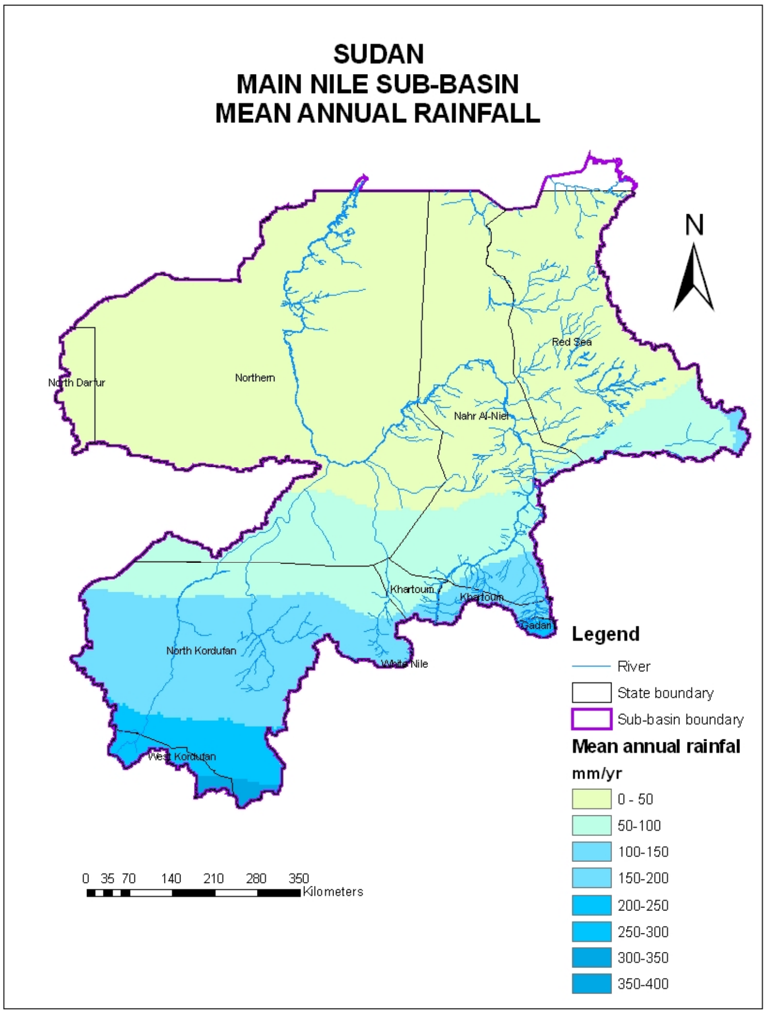
3.2 CLIMATE

3.2.1 Rainfall

Annual rainfall isohyets generally run southwest to northeast, ranging from less than 25mm in the north to 400mm as shown in Figure 3.1. Rain falls mainly between July and September in a single season. Two broad rainfall belts are recognized:

- from < 25mm near the border with Egypt to 150mm near Khartoum, rains are erratic with a coefficient of variation (CV) as high as 100 percent;
- from 150mm to 400mm, rains are variable with CV's as high as 30 percent;

Figure 3.1 : Sudan – Main Nile: Mean Annual Rainfall (mm)



Mean monthly rainfall at Dongola for the period 1981-2000 is shown in Table 3.1, below. It should be noted that rainfall is erratic and there may only be a single event in a given month in the 20-year period, with all other years having no rainfall.

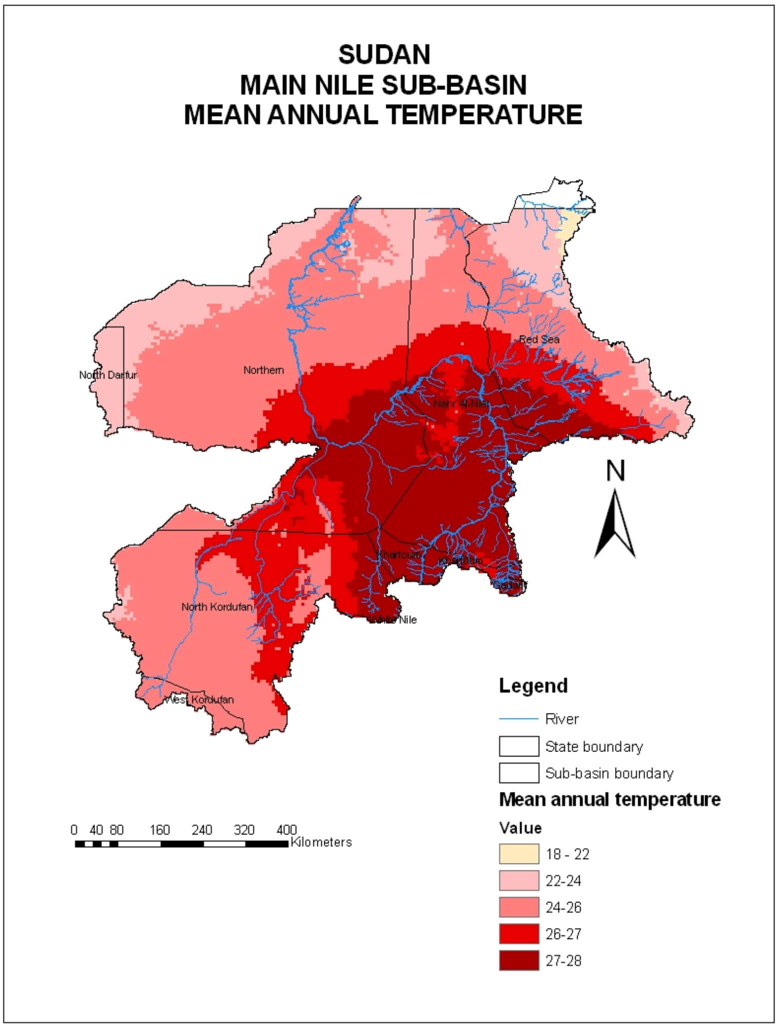
Table 3.1 : Mean monthly rainfall at Dongola (mm)

Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0.06	0.07	0.02	0.01	0.29	3.05	1.04	3.84	0.45	0.64	0	0

3.2.2 Temperature

Daily minimum and maximum temperatures in January are 14°C and 33°C and those in May are 24° and 44°C respectively. Highest mean annual temperatures occur in the eastern clay plains, rather than the north where minimum temperatures bring down the mean (Figure 3.2). Daily evaporation rates range from 12mm in August, the month of maximum cloud cover, to 21mm in May.

Figure 3.2 : Sudan – Main Nile: Mean annual temperatures.



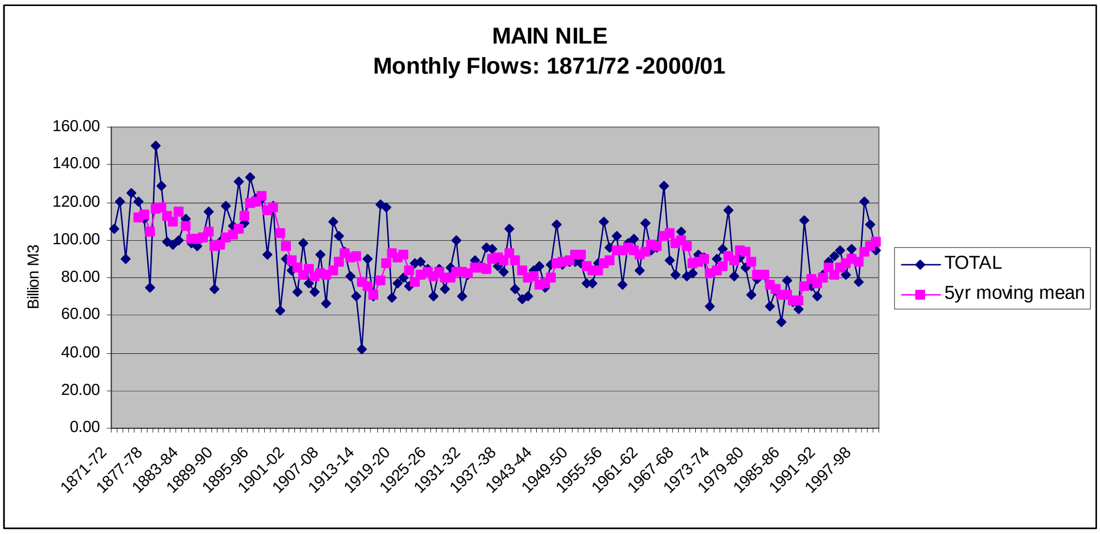
3.3 SURFACE WATER RESOURCES

The average annual flow of the Main Nile at Khartoum is approximately 74,300 Mm^3. (equivalent to 2356 m^3/s). The Main Nile from the confluence of the Blue and White Niles at Mogren flows 1,500 km from Khartoum to Lake Nubia. The river flows through a series of cataracts with a total drop of 250m. The seasonal flow pattern exhibits the combined characteristics of the two main tributaries with the seasonal pattern of the Blue Nile superimposed on the regular pattern of the White Nile.

There are a number of ephemeral streams (wadis and khors) that flow during the rain season. The more important of these include the Gash on the east bank and the El Milk on the west bank.

The total annual flow at the border with Egypt has historically been taken (before any significant abstraction) as 84km^3 (1905-1959). However, there are considerable year-on-year as well as periodic variations (Fig.3.3).

Figure 3.3 : Main Nile: Monthly Discharges and 5 year moving mean 1871/72 - 2000/01



From 1871 to 1896 saw a period of high flows, a period that saw high lake levels across East Africa. Between 1901 and 1975 annual discharges averaged around 87km^3. The decade from 1976 to 1987 saw a series of very low flows – average annual flow about 76km^3, since when flows have increased again.

3.4 HYDROLOGICAL DATABASE

Hydrological data were obtained for this analysis from four sources:

- Ministry of Irrigation and Water Resources (MIWR) of Sudan,
- Eastern Nile Technical Regional Office (ENTRO),

- RAPSO Model Data Files (as used in "Building Of Electricity Sector Database & Long-Term Power System Planning Study, Interim Report No. 3 : The Data Book, PB Power 2006".

- Various published reports (see Section 3.10 References).

The MIWR dataset contained data for various hydrological stations distributed over the Blue Nile and Main Nile river.

3.5 KEY HYDROMETRIC STATIONS

Hydrometric stations on the Blue Nile and Main Nile river in Sudan and their respective periods of records are as follows:

- Blue Nile at El Diem (1912 – date)
- Blue Nile at Khartoum (1900 – date)
- Main Nile at Tamaniat (1911 – date)
- Main Nile at Dongola (1962 – date).

3.5.1 Blue Nile at El Diem

Regular flow gaugings at El Diem started in 1962 and many measurements (over 200) have been carried out in some years. The site was reported to be *"stable and the rating is reliable and precise".* (Sutcliffe and Parks, 1999). However, it is understood from communications with individuals in Sudan that the cableway is now in poor condition and, as a result, current meter measurements have not been carried out for some 20 years.

3.5.2 Blue Nile at Khartoum

Regular gaugings have been made at or near Khartoum since 1902, with about 40 per year at Soba for low flows and 30 per year at Khartoum for high flows. The frequency of gaugings is the key to the precision of the flow record.

3.5.3 Main Nile at Tamaniat

The Tamaniat gauging station is located some 50 km downstream of Khartoum, below the confluence of the Blue Nile and White Nile. Records commenced in 1911 and continue to the present time.

3.5.4 Main Nile at Dongola

The hydrometric station at Dongola was established in 1962 following the flooding of downstream sites at Wadi Halfa and Kajnarty. Flows were recorded at Wadi Halfa from 1911 to 1931 and then at Kajnarty from 1931 to 1962. However, as there are no inflows in the reach and losses are small the combined record can be considered continuous from 1890. Records show that the annual number of gaugings at Dongola has typically been some 100 - 120, although in some 20% of years the frequency fell to approximately 80/year.

The Dongola hydrometric station has been selected as the key station for the present studies of the Dal hydropower project because of its proximity to the Dal site and length of available record.

3.6 TIME SERIES FOR FLOWS AT DONGOLA AND DAL SITE

3.6.1 Dal Site

The Dal site is located some 280 km downstream of the Dongola hydrometric station and some 120 km upstream of the former Wadi Halfa hydrometric station. There are no intervening catchments. Accordingly the time series for Dongola has been adopted directly for the Dal site. Recorded average monthly flows for Dongola are given in Table 3.2.

Table 3.2 : Summary of Average Discharge for Dongola (1890-1995) (m^3/s)

Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
1335	1053	847	864	812	837	1967	6982	7930	4979	2611	1694	2668

The flow sequence for the period 1954 – 2003 which has been adopted for reservoir simulation studies is presented in Annex A, located at the end of this Chapter. The flow sequence used in modelling takes account of future abstractions for irrigation as described in Chapter 4.

3.7 FLOOD STUDY

Flood estimates are required for two main purposes:

- Design of the Dal spillway to ensure safe passage of flood flows
- Design of river diversion works for Dal dam construction period

Frequency analysis has been carried out of flows at Dongola as shown in Table 3.3, below.

Table 3.3 : Frequency Analysis of Flood Flows (m^3/s) for Nile at Dongola

Return Period (Years)	Method	
	LP3	Gumbel
10000		21,670
1000		18,240
500		17,200
100	13,790	14,800
50	13,080	13,760
20	12,100	12,370
10	11,260	11,300
5	10,340	10,190

The construction of the Merowe project upstream of Dal will alter the flood regime in the Nile at Dongola and further downstream at Dal. Depending on the exact mode of operation a significant attenuation of flood magnitude in the Nile at Dongola and Dal can be anticipated associated with the routing of floods through the Merowe reservoir, particularly with the lower return period events. A design capacity of 10,000 m^3/s has been adopted for the river diversion works during construction approximately equivalent to the 1 in 20 year flood.

For reasons of dam safety, it will be necessary to ensure that flood releases from Merowe can pass the Dal dam safely under all foreseeable circumstances. Accordingly, a spillway capacity of 20,000 m^3/s has been adopted for the Dal site, similar to the design capacity of the Merowe spillway.

3.8 SEDIMENT

3.8.1 General

The average annual sediment in the Main Nile entering the High Aswan reservoir (Lake Nasser/Nubia) has been variously estimated to be 120 – 142 million tons of which approximately 72 percent is estimated to arise from the Blue Nile, 25 percent from the Atbara and 3 percent from the White Nile.

As there are no inflows between the Dal site and Lake Nasser/Nubia the measurements of sediment deposition in the High Aswan reservoir effectively represent the sum of the total sediment discharge at Dal for the same period. The following sections describe measurements of sediment discharge in the Main Nile and estimates of sedimentation at in the High Aswan reservoir leading to an estimate of sediment discharge at the Dal site.

It should be noted that sediment concentrations in the Nile are significantly affected by the operating policies and procedures at Roseires and Sennar reservoirs where water levels are kept low during the early part of the season in order to flush as much sediment as possible through the reservoir and thereby maintain the maximum active storage. Thus sediment concentrations from the period prior to completion of the Roseires reservoir in 1961 are not directly comparable with later figures which reflect not only the flushing regime but also the effects of sediment deposition in Roseires reservoir.

3.8.2 Sediment Measurements

Measurements of suspended sediment concentration have been carried out regularly at hydrometric stations in Sudan and Egypt since 1929. Measurements were carried out between Halfa (or Kajnarty) and Gaafra since 1929 and more recently at Dongola since 1971.

Average values of suspended sediment at Halfa and Kajnarty for the period 1929 to 1963 are presented in the Nile Waters Study and reproduced in Table 3.4, below. It can be seen that the average sediment discharge over the period 1929 to 1963 was some 133.7 million tonnes per year, of which some 98.5% was discharged in the period 21 July to 20 November.

Table 3.4 : Sediment Measurements at Halfa / Kajnarty, 1929 - 1963

Period		Concentration (ppm)	Total Suspended Sediment (Mt)
July	1 – 10	70	0.07
	11 - 20	128	0.21
	21 – 31	418	1.52
August	1 – 10	1450	7.66
	11 – 20	2861	19.61
	21 – 31	3425	28.95
September	1 – 10	3260	26.20
	11 - 20	2449	18.35
	21 - 30	1827	12.12
October	1 - 10	1371	8.14
	11 - 20	971	4.80
	21 - 31	671	2.60
November	1 - 10	397	1.23
	11 – 20	267	0.59
	21 - 30	187	0.34
December	1 – 10	136	0.21
	11 – 20	118	0.17
	21 – 31	108	0.15
January	1 – 10	93	0.11
	11 – 20	82	0.09
	21 – 31	74	0.08
February	1 – 10	64	0.06
	11 – 20	59	0.05
	21 - 28	57	0.04
March	1 - 10	53	0.03
	11 - 20	51	0.03
	21 - 31	52	0.04
April	1 - 10	50	0.04
	11 - 20	49	0.04
	21 - 30	48	0.04
May	1 – 10	41	0.03
	11 - 20	39	0.02
	21 - 31	39	0.02
June	1 - 10	39	0.02
	11 - 20	43	0.03
	21 - 30	49	0.04
TOTAL			133.73

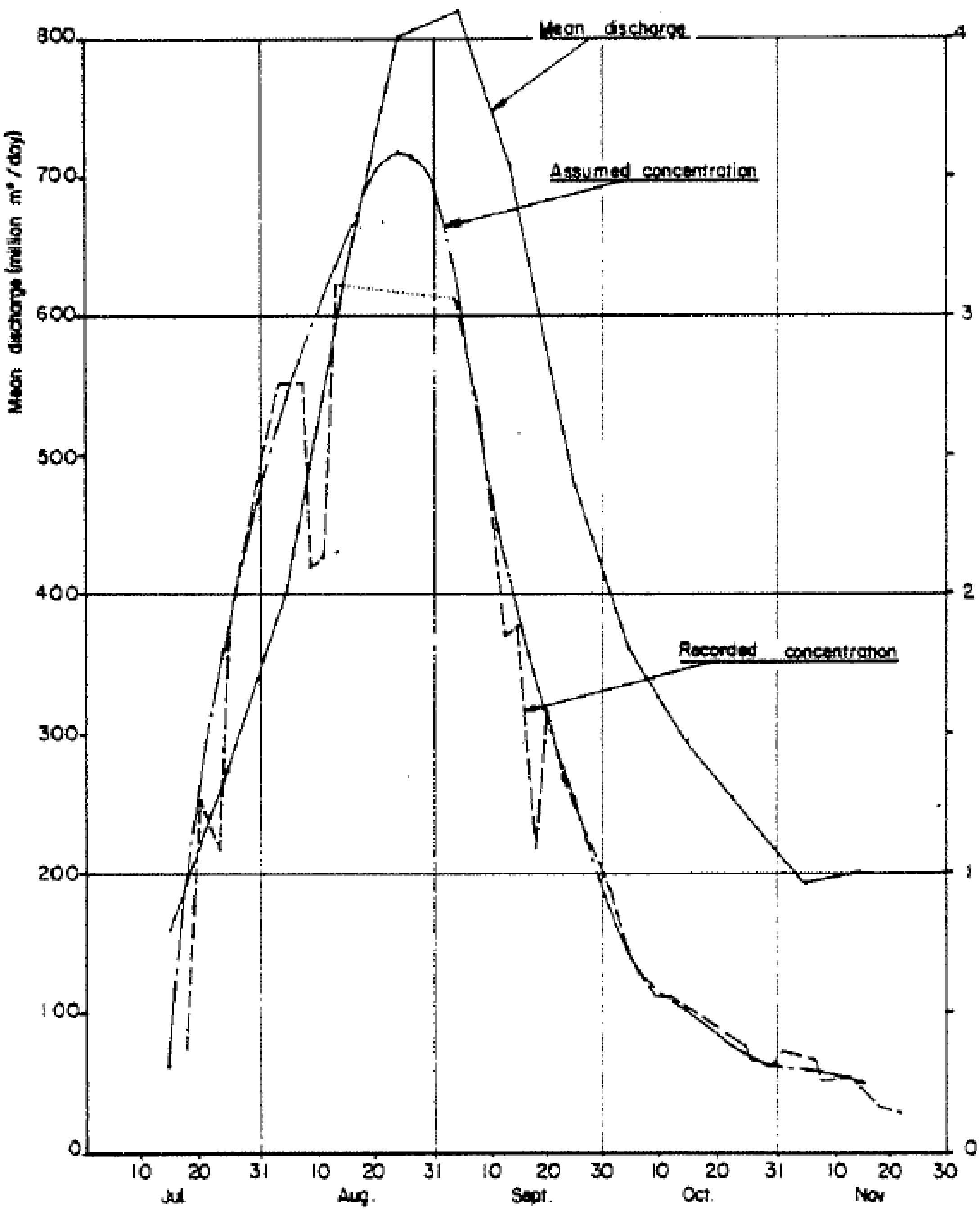
Measurements at Dongola in 1971 are reported in the Nile Waters Study (Coyne et Bellier et al, 1979). Measurements over the high flow period from 18 July to 22 November are illustrated in Figure 3.4, although it should be noted that no measurements were made during the peak flow period from 14 August to 4 September. The results of the measurements are summarised in Table 3.5, below.

Table 3.5 : Sediment Measurements at Dongola, 1971

Period		Mean Discharge (m^3/s)	Concentration (ppm)	Total Suspended Sediment (Mt)
July	11 – 20	1817	300	0.47
	21 – 31	3183	1800	4.95
August	1 – 10	4676	2750	11.1
	11 – 20	7199	3200	19.9
	21 – 31	9282	3600	32.5
September	1 – 10	9502	3000	24.6
	11 - 20	8218	2050	14.5
	21 - 30	5602	1250	6.05
October	1 - 10	4201	700	2.54
	11 - 20	3403	500	1.50
	21 - 31	2859	350	0.86
November	1 - 10	2222	300	0.58
	11 - 20	2338	250	0.5
TOTAL				120

Measurements for a single year do not accurately reflect the long-term average sediment discharge. However, it can be seen that the figures for sediment discharge at Dongola for 1971 are somewhat lower than the long term mean presented in Table 3.4. This is likely to be due, in part, to the completion of the Roseires dam and the consequent deposition of a proportion of the sediment load in the Roseires reservoir.

Figure 3.4 : Sediment Concentration at Dongola (1971)



Source: Nile Waters Study

Data has been obtained for sediment concentrations and flows for the Main Nile at El Koro, upstream of Dongola for the years 2001 to 2003. The data is summarised in Tables 3.6 and 3.7, below.

Table 3.6 : Sediment Concentration at El Koror (u/s of Dongola)

Period	2001	2002	2003
July III	n.a.	n.a.	n.a.
Aug. I	2898	6300	n.a.
Aug. II	3328	7163	5943
Aug. III	1639	5362	4004
Sept. I	2526	2969	3571
Sept. II	1841	1465	4095
Sept. III	1032	801	1273
Oct. I	545	499	911
Oct. II	n.a.	352	537
Oct. III	n.a.	320	155
Nov. I	n.a.	n.a.	139

Table 3.7 : Sediment Discharge at El Koror (u/s of Dongola)

Period	2001	2002	2003
July III	n.a.	n.a.	n.a.
Aug. I	21.9	22.2	n.a.
Aug. II	30.6	42.5	37.4
Aug. III	18.1	33.1	30.4
Sept. I	21.2	13.8	26.2
Sept. II	13.5	4.7	22.5
Sept. III	5.3	2.3	4.7
Oct. I	1.7	1.1	3.3
Oct. II	n.a.	0.7	1.7
Oct. III	n.a.	0.5	0.3
Nov. I	n.a.	n.a.	0.2
Sub-total	112.3	120.8	126.7
Adjustment for remainder of year	11.7	5.0	12.2
Estimated Total	124	125.8	138.9

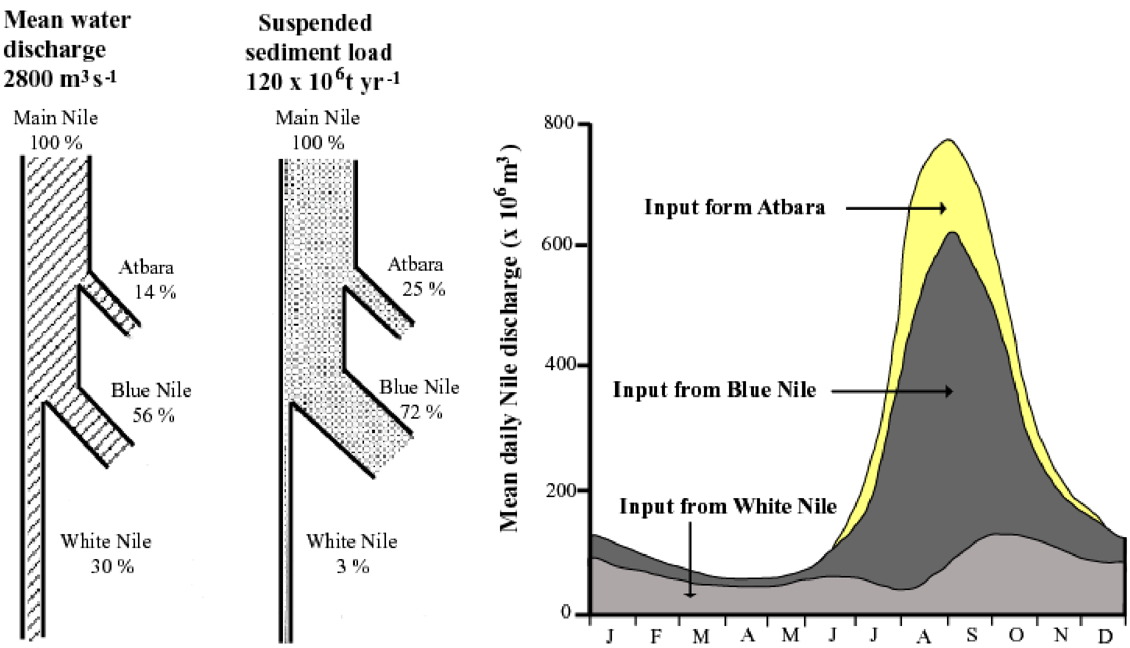
It can be seen that average sediment concentrations for the flood season range from some 500 ppm to over 7,000 ppm. Maximum recorded suspended sediment concentrations for the period 2001 to 2003 are reported to be in the range 12,000 ppm to 25,000 ppm.

It can be seen that the suspended sediment discharge for the period August to October ranged from 112.3 Mt to 126.7 Mt over the period 2001 to 2003. When account is taken of sediment discharge for the remainder of the year (data for which has not been received) it is estimated that the annual suspended sediment discharge would probably range from some 124 Mt to 140 Mt.

3.8.3 Sediment Deposition in High Aswan Dam Reservoir

The suspended sediment load entering Lake Nasser/Nubia originates almost entirely from the Ethiopian Highlands (Figure 3.5). Some 97 percent is derived from the Blue Nile (72%) and the remainder from the Atbara (25%). The mean water discharge differs considerably with the White Nile contributing 30 percent and the Blue Nile and the Atbara 72 and 25 percent respectively.

Figure 3.5 : Mean Discharge and Suspended Sediment Load for Nile Basin.



Source: Cooperative Regional Assessment for Watershed Management, Transboundary Analysis, Country Report, Egypt, Julyy 2006.

The concentration of suspended sediment entering Aswan High Dam Reservoir has a seasonal variation similar to the flow hydrograph. However, the peak discharge and peak suspended sediment concentration do not occur simultaneously. The suspended sediment concentration rises to a maximum (5,000 ppm) many days before the peak of water discharge. The lag time between the peak of the water discharge and the suspended sediment concentration varies from year to year, and on average is approximately 10 days.

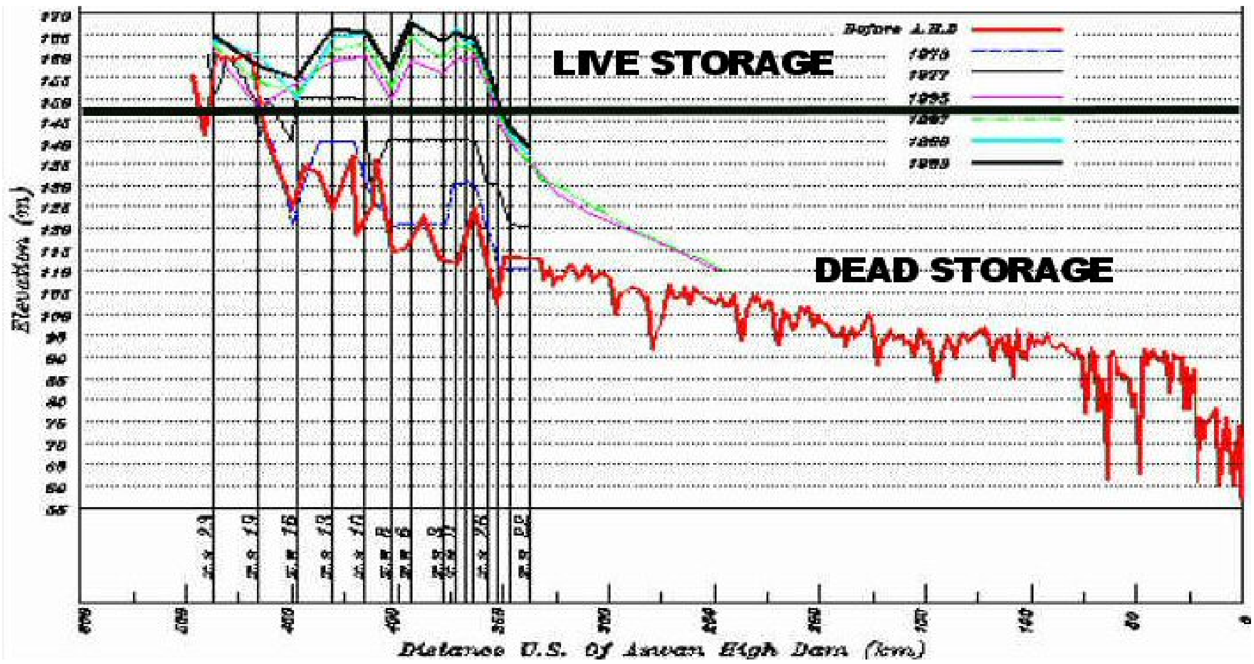
Shalash (1982) estimated the total annual inflow as 142 million tons, the average rate of outflow as 6 million tons with a net sedimentation within the Lake of 136 million tons. Using an average sediment density of 1.56 g cm^{-3} and corrected for compaction (dry weight density of 2.6 g cm^{-3} and a porosity of 40 %), the amount of annually retained sediment of 136 million tons of suspended sediment corresponds to an accumulated volume of 87 million m^3 per yr (Shalash, 1982). However, it is important to note that there is considerable annual variation in sediment load, ranging from 50 and 228 million tons.

Since 1973 cross-section measurements have been taken at selected points in order to monitor changes in the lake bed. By 1973 about 20 meters of sediment had been deposited near the Second Cataract (345-370 km upstream from the Aswan High Dam). From km 345 to km 285 the deposits decreased to less than 1 meter forming an inland delta some 85 km long. By 2000 the maximum deposits had reached 60 metres near the Second Cataract and deposition of sediment now reached 120 km from the dam. Thus, the inland delta had extended some 165 km and now stretched 250 km.

The extent of the sediment has been measured by Mohamed El-Moattassem et al, 2005). The sediment deposition is concentrated at the head of the Lake mainly in the Sudan. Figure 3.6 illustrates the longitudinal section of the lowest bed elevation of Aswan High Dam Reservoir from year 1964 to 2003 using bathymetric data collected by the Nile Research Institute. The reservoir was designed with 31.6 km^3 of dead storage to accommodate the sediment being retained in the reservoir. In 1982 the Research Institute to Study Effects of the High Dam estimated that the reservoir would function unimpeded by sediment for approximately 362 years (Smith, 1990).

However, it can be seen in Figure 3.6 that 360 km from the dam to 500 km from the dam the sediment is filling up the live storage as well as the dead storage. This is having an immediate impact on the useful storage capacity of the reservoir and thus is reducing the amount of water available for hydro power generation and for irrigation.

Figure 3.6 : Longitudinal bed elevation profiles for Aswan High Dam Reservoir (Source: Mohamed El-Moattassem et al, 2005)



Continuing deposition of sediment in the High Aswan reservoir would result in gradually rising levels in the Nile immediately upstream as the delta formation progresses. In the long term this might begin to affect tailwater levels at the Dal site. However, the construction of the Merowe dam, described in the following section, will reduce the sediment discharge in to High Aswan reservoir and slow the rate of deposition in the delta region.

3.8.4 Impact of Merowe Project

The Government of Sudan is currently constructing the 60 metre high Merowe Dam some 400kms north of Khartoum. The reservoir will submerge the fourth cataract of the Nile and form a 200 km long reservoir. With a surface area of 800 km^2, the lake will have a gross storage of 12.45 km^3 and an active storage capacity of 8.3 km^3. The dam will be fitted with deep sluices that can be used to operate the dam at a relatively low level during the period of highest sediment concentration thereby reducing sedimentation within the reservoir. Exactly how much sediment will be retained by the dam is a matter of some discussion. Three studies are available: (i) by Lahmeyer International, (ii) a study by MIT (Paris, A, T.Yamana and S.Young, 2004) and (iii) by the EAWAG, Switzerland.

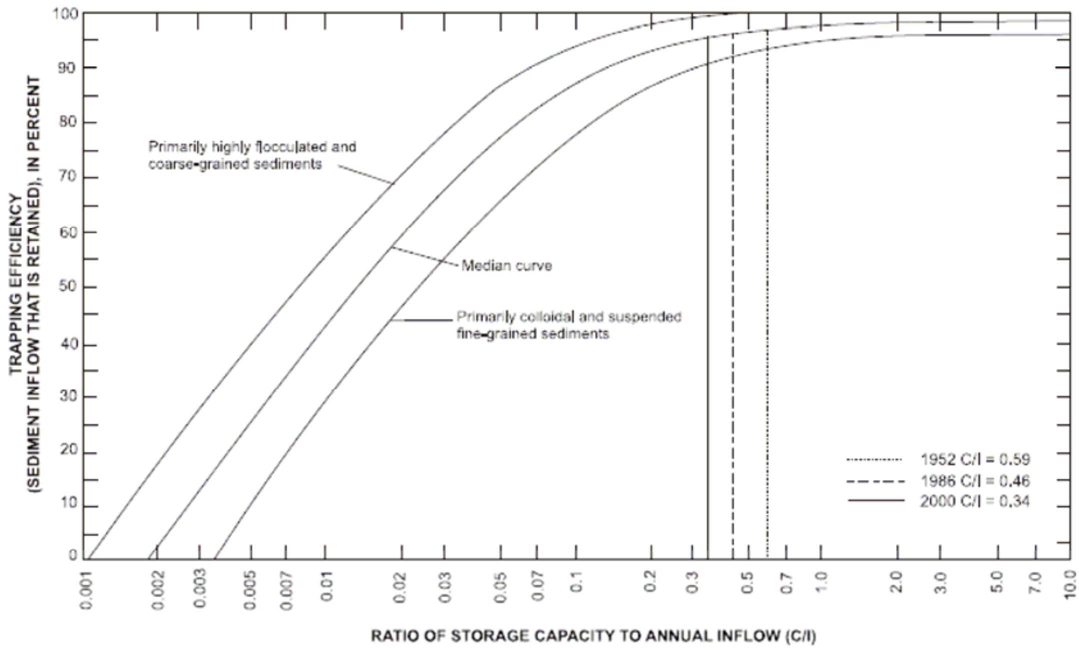
The Lahmeyer study estimates that some 30 percent of the annual mean sediment load of 120 million tons will be retained within the reservoir behind the dam.

The EAWAG study disputes this and claims some 90 percent of the annual sediment load will be retained behind the dam. This study also uses an estimated mean annual sediment load of 143 million tons. The study estimated that the reservoir would fill completely in approximately 150 years.

The MIT study estimates a trapping percent of 84 percent of which 65 percent will rest in the dead storage and 35 percent in the live storage. It used a mean annual sediment load of 128 million tons but notes that this can vary from 50 to 228 million tons. The MIT study looked at the changes in trapping efficiency as the reservoir capacity decreased. It also assumed that the dam would be operated to allow at least 40 percent of the sediment to pass through the sluices in July-August with a net retention rate of 60 percent. It looked at six scenarios of varying flow rates and sediment loads to determine the economic life. Assuming 60 percent retention and a suspended load of 128 millions tons it estimated the economic life of the dam as 105 years.

Brune’s relationship (refer to Figure 3.7, below) suggests a trapping efficiency of some 86% for Merowe assuming that the sediment is primarily fine-grained and colloidal particles. This is broadly in line with the MIT estimate referred to above. However, this analysis does not take account of sediment flushing activities and it could be expected that regular flushing at the start of each flood season would result in a significant reduction in trap efficiency and that some 30-50% of sediment could reasonably be anticipated to pass through the dam into the Main Nile downstream and thereafter into Dal reservoir.

Figure 3.7 : Reservoir Trapping Efficiency Relationship (Brune, 1953)



3.8.5 Sediment Balance and Inflow to Dal Reservoir

Recent measurements over the period 2001 to 2003 suggest that the mean annual suspended sediment discharge in the Main Nile amounts to some 140 Mt/yr.

It is noted that this figure is significantly lower than recent estimates for average sediment discharge in the Abbay (Blue Nile) at Kessie in Ethiopia of 220 Mt/yr produced as part of the present study, based on sediment concentration measurements carried out at the Kessie hydrometric station in 2004.

A sediment balance for the Nile River was prepared as part of the Cooperative Regional Assessment (CRA) as shown in Table 3.8 below. It can be seen in this analysis that sediment discharge entering Karadobi has been assumed as 92 Mt/yr compared to a current estimate for sediment discharge at Kessie (slightly upstream of Karadobi), based on 2004 data of 220 Mt/yr in this study.

There is a high level of uncertainty regarding many of the estimates involved in deriving a sediment balance for the Nile given that many of the individual components of the balance are highly variable from year to year and that measurements are infrequent and imprecise. Some data is now more than 40 years old whilst it is anticipated that sediment discharge will have increased over this period due to pressures of population, agriculture and deforestation.

Table 3.8 : Eastern Nile Basin: Estimated Current Sediment Budget: No Watershed Management Programme and only Existing Dams

LOCATION	NO WSM OR DAMS
	M t/yr
SEDIMENT ENTERING KARADOBI	92.00
SEDIMENT RETAINED IN KARADOBI	0.00
SEDIMENT THRU' KARADOBI	92.00
SEDIMENT ENTERING ABBAY RIVER BELOW KARADOBI (EXCLUDING BELES)	46.81
SEDIMENT ABOVE BELES-ABBAY CONFLUENCE (M t/yr)	138.81
SEDIMENT ENTERING BELES	1.56
SEDIMENT RETAINED IN BELES RESERVOIR	0.00
SEDIMENT THRU' BELES	1.56
SEDIMENT IN ABBAY AT BORDER	140.37
SEDIMENT ENTERING ROSIERES	140.37
SEDIMENT RETAINED IN ROSIERES (%)	15%
SEDIMENT RETAINED IN ROSIERES M t/yr	21.06
SEDIMENT THRU' ROSIERES	119.31
SEDIMENT ENTERING RAHAD + PUMP SCHEMES	119.31
SEDIMENT RETAINED IN RAHAD + PUMP SCHEMES (%)	1.88%
SEDIMENT RETAINED IN RHAD = PUMP SCHEMES PUMP (M t/yr)	2.24
SEDIMENT AFTER RAHAD = PUMP SCHEMES	117.07
NET LOSS TO PERMANENT STORAGE IN RIVER BED/ALLUVIAL PLAINS (%)	1.25%
NET LOSS TO PERMANENT STORAGE IN RIVER BED/ALLUVIAL PLAINS (Mt/yr)	1.46
SEDIMENT ENTERING SENNER RESERVOIR	115.61
SEDIMENT RETAINED IN SENNER (%)	10%
SEDIMENT RETAINED IN SENNER	11.56
SEDIMENT THU SENNER	104.05
SEDIMENT AT GEZIRA/MANAGIL INTAKE	104.05
SEDIMENT RETAINED IN GEZIRA/MANAGIL (%)	7.5%
SEDIMENT RETAINED IN GEZIRA/MANAGIL M t/yr	7.88
SEDIMENT AFTER GEZIRA	96.17
SEDIMENT FROM RAHAD-DINDER	9.19
SEDIMENT BELOW RAHAD-DINDER CONFLUENCE	105.36

LOCATION	NO WSM OR DAMS
	M t/yr
NET LOSS TO PERMANENT STORAGE IN RIVER BED/ALLUVIAL PLAINS (%)	2.5%
NET LOSS TO PERMANENT STORAGE IN RIVER BED/ALLUVIAL PLAINS (Mt/yr)	6.32
BLUE NILE SEDIMENT AT KHARTOUM	99.04
SEDIMENT FROM WHITE NILE (3% OF 142mT/YR)	4.26
SEDIMENT MAIN NILE AT KHARTOUM (Mt/yr)	**103.30**
NET LOSS TO PERMANENT STORAGE IN RIVER BED/ALLUVIAL PLAINS (%)	4%
NET LOSS TO PERMANENT STORAGE IN RIVER BED/ALLUVIAL PLAINS (Mt/yr)	4.13
SEDIMENT MAIN NILE ABOVE ATBARA	**99.16**
SEDIMENT FROM ATABARA	58.43
SEDIMENT MAIN NILE BELOW ATBARA CONFLUENCE	**157.60**
NET LOSS TO PERMANENT STORAGE IN RIVER BED/ALLUVIAL PLAINS (%)	4%
NET LOSS TO PERMANENT STORAGE IN RIVER BED/ALLUVIAL PLAINS (Mt/yr)	6.30
SEDIMENT ENTERING MEROE RESERVOIR (M t/yr)	151.29
SEDIMENT RETAINED IN MEROE RESERVOIR (%)	0%
SEDIMENT RETAINED IN MEROE RESERVOIR (M t/yr)	0.00
SEDIMENT BELOW MEROE DAM (M t/yr)	151.29
NET LOSS TO PERMANENT STORAGE IN RIVER BED/ALLUVIAL PLAINS (%)	6%
NET LOSS TO PERMANENT STORAGE IN RIVER BED/ALLUVIAL PLAINS (Mt/yr)	9.08
SEDIMENT ENTERING LAKE NASSER/NUBIA (M t/yr)	142.22
SEDIMENT ENTERING LAKE NASSER/NUBIA (M M3/yr)	133.85
SEDIMENT RETAINED IN LAKE NASSER/NUBIA (%)	96%
SEDIMENT RETAINED IN LAKE NASSER/NUBIA (M t/yr)	136.53
SEDIMENT RETAINED IN LAKE NASSER/NUBIA (M m3/yr)	128.50
SEDIMENT THRU LAKE NASSER	5.69

Source: Draft CRA report on Distributive Analysis (January 2007)

Techniques adopted for many of the measurements have changed over the years – for example, sediment sampling at El Deim, upstream of Roseires was at one time carried out in a precise manner using 25 point samples on 5 verticals across the river but for the last 20 years has been based on a single bottle sample taken at the water surface adjacent to the river bank.

Other elements in the sediment balance such as deposition in irrigation systems are not regularly measured, whilst deposition on flood plain areas is extremely imprecise, but probably accounts for a large quantity of sediment especially in high flood years when sediment discharge and flooding is at its highest.

With significantly higher estimates of sediment transport at Kessie on the Abbay (Blue Nile) River in Ethiopia for current conditions, the sediment budget given in Table 3.8 would necessarily be disturbed. However, there appears to be no reason why the budget could not be adjusted to reflect greater sediment inflows at Kessie. It would require greater depositions along the Nile and the possibility of adopting a different trap efficiency and density factor for converting surveyed volume of sedimentation (m^3) in Roseires reservoir and Lake Nubia/Nasser to equivalent tons.

Experience on other projects is that sediment reductions downstream of new dams such as Merowe are often less than estimated. This is thought to be because the erosion of the riverbed and banks downstream of the new dam provides a continuing source of sediment until a new regime becomes established. The alluvial material comprising the riverbed and banks of the Nile between Merowe and Dal are thus likely to provide a source of substantial quantities of sediment entering Dal reservoir for many years to come.

Although the overall balance of sediment along the Nile downstream of Merowe is therefore uncertain, the average sediment discharge at the Dal site following construction of the Merowe project can probably be expected to lie within the range 75Mt to 100 Mt, depending on the effectiveness of the sediment flushing regime at Merowe. Much of this sediment will be very fine grained and will have a lower trapping efficiency in Dal than would be the case without Merowe upstream. A trapping efficiency of 55 % has been estimated based on Brune's relationship for primarily fine grained and colloidal particles and assuming that sediment flushing at Dal would not take place. Under these circumstances it is anticipated that sediment deposition in the Dal reservoir will be some 40 - 55 Mt/year, or some 30 – 40 Mm^3/year.

3.9 EVAPORATION

Recorded mean monthly evaporation at Dongola is presented in Table 3.9, below.

Table 3.9 : Mean monthly evaporation at Dongola (mm)

Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
145	166	206	236	259	263	238	247	267	257	186	144	3614

Estimated open water evaporation (Penman estimate, after Shahin, 1985) at Wadi Halfa is shown in Table 3.10.

Table 3.10 : Estimated Open Water Evaporation at Wadi Halfa (mm)

Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
140	162	220	261	288	294	298	288	258	239	183	124	2755

3.10 REFERENCES

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Annex A – Hydrology Data – Flow Sequence for Reservoir Modelling

□ Dal Alt 2 Reservoir and Power Station 52

Average monthly values and annual values for period 1/1954 to 12/2003

Month	Inflow in period (m3/s)	Turbine discharge in period (m3/s)	Downstream flow in period (m3/s)	End-period reservoir level (m)	Average net head in period (m)	Average efficiency in period (p.u.)	Energy Dmd. in period (GWh)	Energy Gen. in period (GWh)	Max. power available in period (MW)	No. sets utilised on avge. in period	Net Evapo-ration (Mm3)	Spill (m3/s)
1	786.26	758.18	766.81	201.00	19.67	.904	.00	96.93	297.4	6.	52.08	8.64
2	784.02	761.98	761.98	201.00	19.67	.904	.00	89.80	297.5	6.	53.76	.00
3	951.32	925.23	925.28	201.00	19.49	.904	.00	118.68	297.5	7.	69.75	.05
4	1065.58	1034.85	1036.06	201.00	19.36	.904	.00	127.49	297.5	7.	76.50	1.22
5	1029.58	996.59	996.59	201.00	19.43	.904	.00	127.61	340.0	7.	88.35	.00
6	2818.49	2085.85	2784.81	201.00	17.56	.904	.00	233.65	327.1	8.	87.30	698.96
7	2721.29	2010.14	2689.00	201.00	17.68	.904	.00	233.75	327.6	8.	86.49	678.86
8	6067.59	1964.65	6035.64	201.00	15.40	.904	.00	200.01	270.4	8.	85.56	4070.99
9	5653.33	1880.92	5622.08	201.00	15.71	.904	.00	187.48	275.2	8.	81.00	3741.17
10	2496.05	1848.93	2467.93	201.00	17.92	.904	.00	216.51	328.6	8.	75.33	619.00
11	1330.68	1072.26	1307.76	201.00	19.12	.904	.00	125.07	335.7	7.	59.40	235.50
12	1580.63	1520.13	1561.88	201.00	18.75	.904	.00	185.77	339.2	8.	50.22	41.75
Annual values												
Mean	2280.16	1408.64	2252.72	201.00	18.31	.904	.00	1942.76	311.3	7.	865.74	844.08
Min	1366.19	1118.57	1338.81	201.00	17.45	.904	.00	1608.76	298.3	7.	865.74	220.24
Max	3327.87	1806.93	3300.50	201.00	19.08	.904	.00	2480.85	321.9	8.	865.74	1629.40
StDv	431.49	140.12	431.49	.00	.35	.000	.00	172.27	5.3	0.	.00	327.16

4. RESERVOIR MODELLING

4.1 INTRODUCTION

The objective of the reservoir modelling studies that have been carried out comprise definition of the reservoir operation and energy outputs of the Dal project. Computer simulations have been carried out as necessary to estimate on a comparable basis the energy characteristics of the potential alternative scheme configurations.

The simulations have been performed employing a program named RAPSO that has been developed over a long period of years to represent seasonal and annual operation of any combination of hydroelectric schemes in some detail, and of which an application was set up and calibrated for the recent National Electricity Corporation (NEC) long-term power system planning study to represent all existing and potential schemes in the Sudanese Nile system. That application was supplied to NEC under licence and subsequently employed also for a feasibility study of possible irrigation as might be associated with the Merowe hydroelectric scheme now under construction on the Main Nile. For the current pre-feasibility studies the program application has been extended to include potential Ethiopian schemes and also High Aswan in Egypt.

The configuration of the main irrigation and hydroelectric system now modelled for the application is shown diagrammatically in Figure 4.1. As can be seen in that figure, the existing and potential future systems are represented as a series of interconnected nodes, each representing either a reservoir and power station, or a reservoir, or a water inflow or water extraction or flow calibration point. As defined by the user, any particular case study may utilise only a selection of the nodes shown in the figure, while for simulation of any one scheme the reservoir inflows reflect the upstream flows as measured at the perimeter of the system and automatically within each program run make due allowance for:

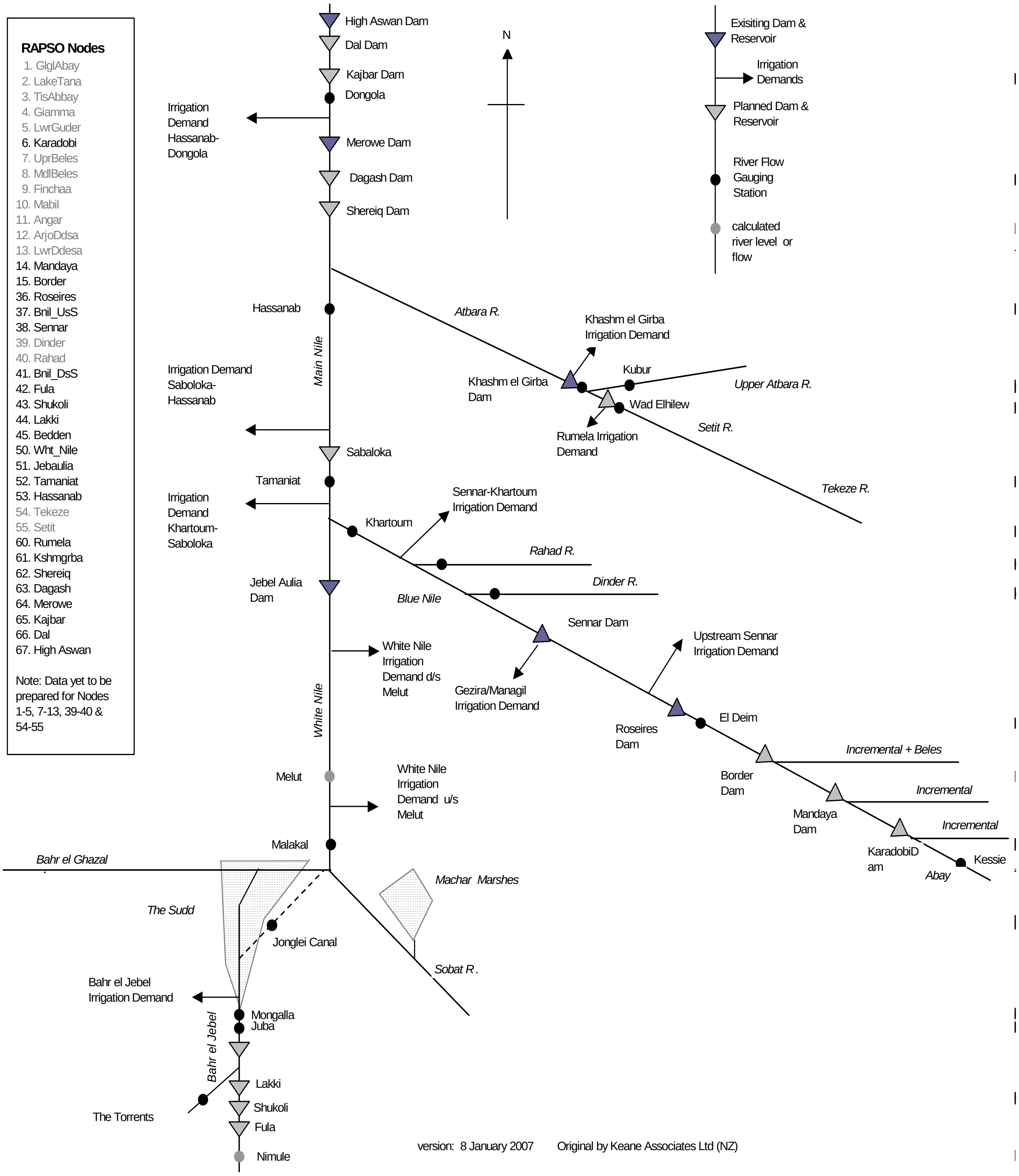
- water abstractions at the various irrigation supply points,
- optimisation of the operation of all upstream reservoirs and power plants in the system simulated, and
- losses from reservoirs and the various river reaches.

The modelling for this study is based on conventional methodology whereby system operation is simulated continuously over a period of hydrological record defined in terms of data time series, and supply reliabilities are measured over the hydrological period in terms of incidences of failure to supply demands in full. As appropriate, the various reservoir operating policies are represented by applying water demands, rule curves and time-of-filling rules and then using the program automatically to:

(a) maximise firm energies with the desired reliability and without irrigation supply reliabilities being adversely affected, and then
(b) optimise other rule curves so as to maximise secondary energies without adverse effect on the firm supply reliabilities.

Consistent with previous studies and published data supplements for *The Nile Basin*, this program application employs three simulation time steps per month (these being of lengths 10 days, 10 days and balance-of-calendar-month days).

Figure 4.1 : Abay and Nile system as currently modelled with program RAPSO



4.2 DESCRIPTION OF THE RAPSO PROGRAM

RAPSO (Reservoir And Power Station Operation) provides a detailed computer model of operation of any system of reservoirs, hydroelectric power stations and water supply for other than or in conjunction with hydroelectric purposes. Each "node" of the system is represented by selection of the appropriate combination of the facilities illustrated in Figure 4.2. Extensive facilities enable a model to be calibrated against hydrological records, and the program also provides automatic derivation of:

- firm and average energy characteristics or operating policy defined in terms of various rule curves and demand levels with or without thermal plant available in a supporting role; optimisation can be either to meet water and electricity demands with defined levels of reliability or to maximise the value of energy output against a price forecast or to meet some combination of requirements, for example to supply domestic demands on a firm basis and otherwise maximise the monetary value of exports; and

- statistical results of applying a fixed operating policy from known starting conditions.

All program inputs are arranged as a series of options, with only the selected options having any influence on subsequent calculations. The program is thus entirely data driven and requires no coding modifications when changing from one system to another.

Simulation detail is itself optional, for example the program time step is variable from half an hour to a month and the same program can be used for all stages of scheme development, from initial calculations through to detailed operational analysis for the completed scheme.

Similarly, the program can be used to investigate effects of including greater detail and hence determine the extent appropriate for the circumstances. Thus, for example, representation of water flow and storage can allow for variations such as in i) tunnel and penstock friction losses with water flow, ii) turbine efficiency with both hydraulic net head and flow, iii) generator efficiency with output, and iv) tail-water level with flow. It is thus readily possible to assess errors arising from common simplifying assumptions, such as:

- a constant value of efficiency instead of the real variations with net head and flow

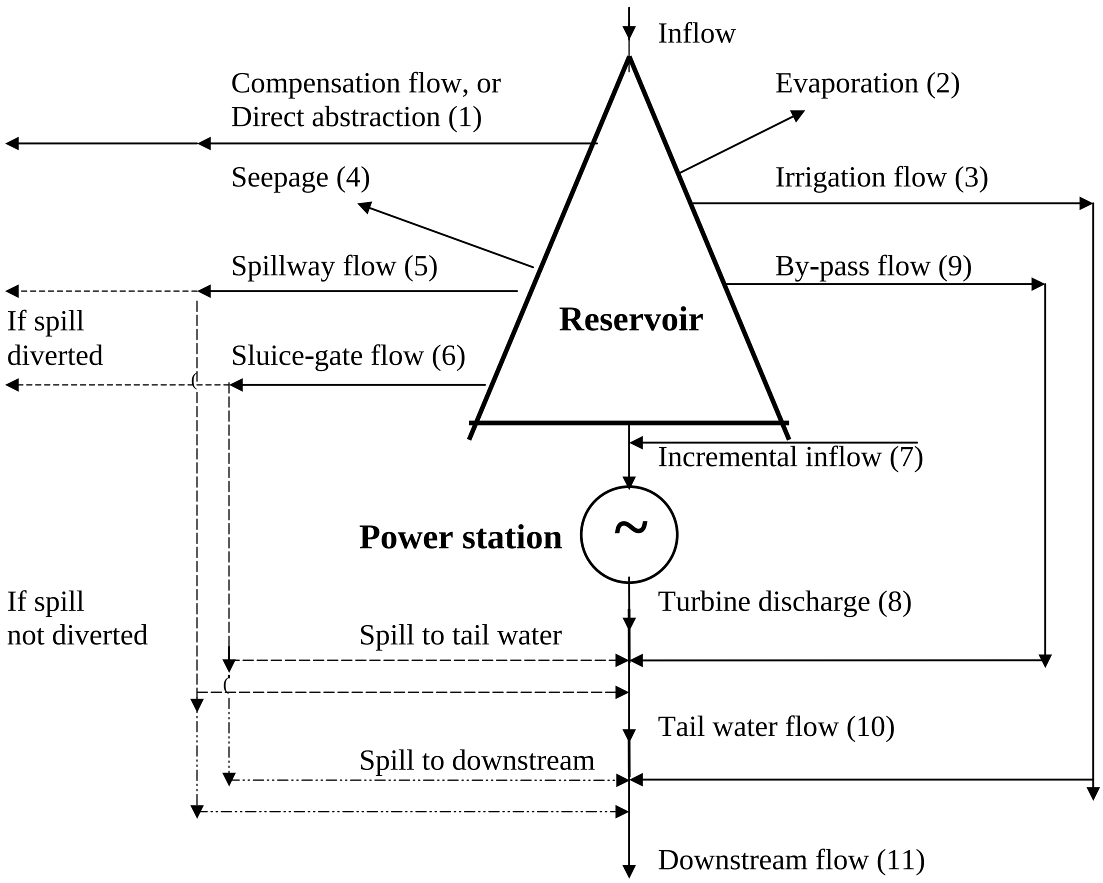
- average rates of flow and reservoir and tailwater levels for each month

Calculations in RAPSO are controlled according to water or energy demands or both and also by various reservoir seasonal control levels: in all cases an iterative technique with rapid convergence is employed (as outlined in Figure 4.3), ensuring that a compatible solution is obtained for each time step in turn. Cascade effects can be fully evaluated with any applicable water flow limits, times of water travel and losses between successive nodes being explicitly accommodated. Auxiliary software provides automatic data or results time series manipulation and presentation in tabular form, and also graphically using Microsoft Excel.

RAPSO has facilities for automatic determination of “hydro conditions” as commonly required for input to computer programs for power system expansion planning.

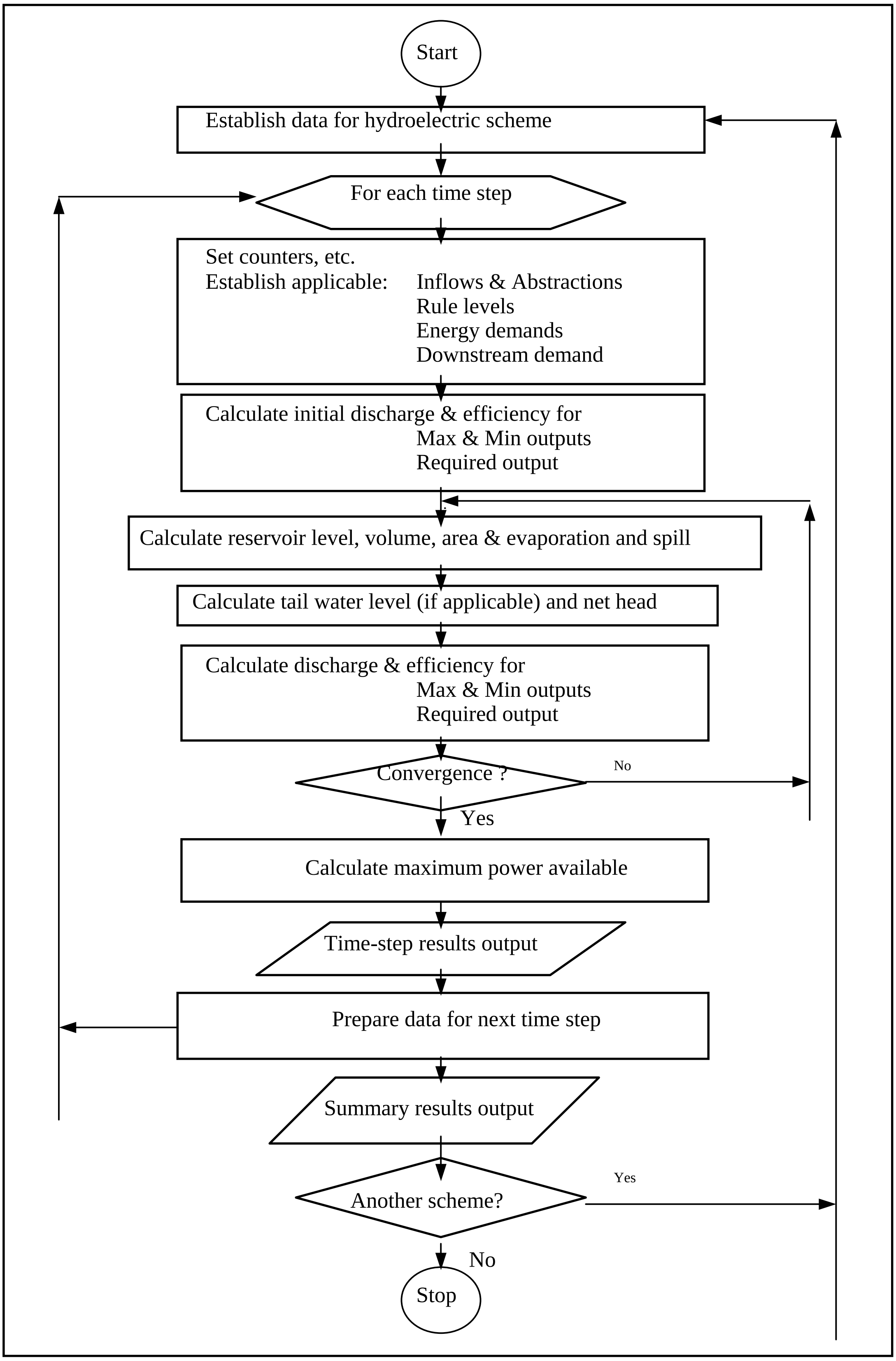
The program is written in FORTRAN 77 and is now applied via a data-management, operation and graphical / tabular results-display system implemented in Microsoft Excel. RAPSO does, however, remain fully backwards compatible with earlier DOS-based versions.

Figure 4.2 : Reservoir / Power Station Module and Water Flows



Notes :	
1. Compensation or direct abstraction (not available for power generation and excluded from downstream flow) is as input for the calendar month and given priority over all other demands 2. Evaporation is obtained from the applicable input or derived net evaporation rate and the calculated reservoir surface area. 3. Irrigation flow is as input for the particular time step, and is given priority over turbine discharge. 4. Seepage is the input value. 5. Spillway flow is calculated from a spillway characteristic if present, or else is the surplus with the reservoir at full supply level. 6. Sluice-gate flow is the surplus leaving the reservoir at flood protection level interpolated within the calendar month or, if this level is above spillway crest level, the surplus over spillway capacity. 7. Incremental inflow is as input for the particular time step.	8. Turbine discharge for each time step is limited by water availability or discharge capacity, or : - that satisfying the greater of the energy or downstream flow demand, or - limited by generator capacity or turbine capacity under the available net head and otherwise the flow leaving the reservoir level as close as possible to secondary control level. 9. By-pass flow is either zero or, if the turbine discharge is limited as in 8. above, that leaving the reservoir level as close as possible to secondary control level, but subject to by-pass capacity. 10. Tail water flow, whether including or excluding spill flow as adjusted for time-of- travel, is used with the tail water characteristic, if present, to calculate tail water level. 11.Downstream flow, adjusted for time-of-travel, is the inflow to a downstream scheme, if present, in addition to any further incremental inflow.

Figure 4.3 : Hydroelectric Time-Step Calculation Outline



4.2.1 Data input

Data entry to the program is via a variety of comma-separated-value files created and edited within the Windows environment as illustrated in Figure 4.3. This process is facilitated by:

- detailed instructions for use of all files given in the program user manual,
- extensive provision made for the user to include within the files his own annotations and comments, perhaps in his own language, and
- comprehensive data checking facilities, complemented by run-time error messages.
- Items of input data, most being optional and in almost any combination, include:
- system hydraulic configuration
- electricity price forecast
- selection of optimisation methods together with supply reliability requirements
- transmission constraints and loss factors
- length of simulation period
- starting conditions
- length of time step
- values of acceleration due to gravity
- inflows and incremental inflows in defined sequences
- rainfall records and evapo-transpiration rates
- reservoir level / area / volume characteristics with allowance for future siltation
- evaporation or seepage rates
- by-pass or bottom-outlet capacities and flows
- compensation flows and minimum releases
- water demands
- maximum retention levels (with sluice-gate operation assumed)
- spillway configurations and level / flow characteristics
- retention levels above which supplies are greater than demands
- restriction levels below which supplies are less than demands by defined amounts
- minimum drawdown levels
- dead-storage levels (which may be lower than the minima above)
- downstream abstractions unavailable for power generation

- channel capacities and losses
- head-pond levels
- numbers and configurations of tunnels and penstocks
- flow / friction loss characteristics
- numbers of different sizes or types of hydroelectric machines (i.e. impulse or reaction)
- generator capacities and allowances for transmission constraints and losses
- turbine rated outputs and heads
- turbine discharge limits on account of channel capacities or cavitation constraints
- maintenance programmes
- maximum running-plant capacity factors
- whether or not numbers of running machines are to be matched to total plant outputs
- peaking periods and minimum spinning-reserve contributions
- turbine efficiencies either as constants or as variations with net head and flow
- generator efficiencies varying with output
- flow / tailwater level characteristics
- energy demands and whether or not greater supplies are required when available
- output formats and variables
- times of upstream and downstream water travel

4.2.2 Results Output

For confirmation purposes much of the input data is automatically repeated in the RAPSO. output. The calculated results outputs, for each time step, include any combination of:

- electricity and water supply reliabilities
- monetary values of electricity outputs
- downstream flows
- excesses or shortfalls of downstream flows compared with required minimum values
- turbine discharges
- bypass or direct abstraction flows
- evaporation losses

- reservoir levels
- tailwater levels
- gross heads
- net heads
- efficiencies
- energy outputs
- excesses of energy outputs over required minimum values
- shortfalls of energy outputs below required values
- total energy output from all schemes simulated
- maximum power outputs available
- spillway flows
- sluice-gate flows
- totals of spillway and sluice-gate flows
- numbers of machines in operation

The flow values above can be presented either as total flows or as average rates of flow.

Various statistical analyses of input values and calculated results may also be obtained in the output, and the Windows software automates graphical display of selected results.

4.3 APPLICATION OF RAPSO MODEL TO NILE RIVER SYSTEM

In order to model the water balance of the Nile system using RAPSO (the Model) for the purpose of estimating hydroelectric generation under a range of possible scenarios, a limited number of gauging stations were selected to represent the flow balance of the Nile system in Ethiopia and Sudan. The components of the water balance model are as shown in Figure 4.1. Recent flow records for these sites were obtained from the MoI in Sudan and MoWR in Ethiopia. Estimates of abstraction for irrigation and estimates of seasonal net evaporation have been assembled for both countries.

On the Blue Nile the gauges at El Deim, and on the Dinder and Rahad rivers have been assumed to be upstream from any significant irrigation demand on those rivers. Inflow regime changes have been observed in Sudan and reported at Roseires and are attributed to hydroelectric development on the Blue Nile and its tributaries in Ethiopia. Flow data from Ethiopia has been included for the Blue Nile (Abay) at Kessie.

Existing reservoir and hydroelectric power station characteristics have been collected to enable the operation of reservoirs to be modelled under a range of future development scenarios.

The core data for the White and Blue Nile flows in Sudan contained within the RAPSO model was provided by Ministry of Irrigation in Sudan for the Merz & McLellan 1997 Report (M&M1997). These data include inflows to the White Nile at Malakal and to the Blue Nile at El Diem, Rahad and Dinder for the period 1912-94, with some of the series extending to April 1996. These were subsequently updated to 2003 using data provided by the Ministry of Irrigation. These various time series incorporated all data improvements made for different studies up to that time and therefore formed a robust platform for time-series extension using more recent data. Comments on the various data records are provided in the following sections.

4.3.1 Blue Nile

El Deim

Data at this site are taken from M&M1997 and then extended using river level data provided by the MoI for the period 1992-2001. The river level hydrographs for 2000 and 2001 were back-calculated from Roseires inflow data and are consistent with the observed pattern at Khartoum.

Roseires & Sennar Reservoir and Tailwater Levels and Discharges

Time series of these data were provided by the MoI for the period 1992-2001 and were used for model calibration purposes. Initial modelling of flows at Sennar revealed a discrepancy in the water balance. To assist in resolving this, the tailwater level rating for Sennar Dam was checked and found to be inconsistent with the modelled flows. The tailwater level rating was therefore revised using measured water levels (H) and modelled discharges, and a best-fit curve was obtained for the 1992-2001 data. This curve is described by the equation:-

$$\text{Flow (Mm}^3\text{/day)} = 6.9335 \times (H-400)^2 - 33.44 \times (H-400) + 42.363 \qquad r^2=0.96$$

Dinder and Rahad Rivers

Data defining the outflows from these rivers were taken from M&M1997 Report and extended using 1992-2001 river level data and rating curves provided by the MoI. This record is consistent with MoI's computerised (1965-2001) data.

Blue Nile at Khartoum

Water level and flow data for this site from 1992-2001 were obtained from the MoI during a visit to Khartoum in March 2002. The flows were checked for consistency with the El Deim site upstream and these flow records have been improved in consultation with MoI.

4.3.2 Main Nile

Tamaniat, Hassanab and Dongola

Data for these sites from 1992-2001 were obtained from the MoI during a visit to Khartoum in March 2002. Subsequent revisions of flow ratings by MoI have resulted in more consistent Main Nile flow records.

4.3.3 Atbara River

Atbara River at Kubur & Setit River at Elhilew

10-daily flow records for both these sites were obtained from the MoI for the period 1966-2001. The records were extended back to 1912 assuming Kubur and Elhilew flows are 35% and 65% of el Girba Dam inflows.

Khashm El Girba

Inflows to Kashm el Girba reservoir were obtained from MoI for the period 1992-2001. A composite inflow record from 1912-2001 was compiled based on gauge records at the old El Girba gauge, a gauge a Showak and the combined flows of Kubur and Elhilew gauges. A detailed description of the derivation of these flows is included in Appendix A.

4.3.4 Reservoir characteristics

The existing multi-purpose reservoirs on the Nile River system in Sudan, shown in Table 4.1, are used primarily to store water for irrigation purposes. Roseires, Sennar and Khashm el Girba have existing hydroelectric plant and the fourth, Jebel Aulia, is currently being retro-fitted with low head generating plant which is expected to be commissioned by 2005. Work to raise the Roseires Dam, though started, has not progressed as had been planned.

Table 4.1 : Characteristics of Existing Reservoirs

Reservoir	River	Dam Completed	Live Storage MDm3 +	Full Supply Level (masl)	Minimum Operating Level (masl)	Installed capacity (MW)
Jebel Aulia	White Nile	1937	3.89	377.4	372.5	28.8*
Roseires	Blue Nile	1966	2.12	481	467.6	280
Sennar	Blue Nile	1925	0.48	421.7	417.2	15
Khashm el Girba	Atbara	1964	0.617	474	463.5	12

4.3.5 Reservoir storage

The storage volume of reservoirs has been reduced owing to accumulation of sediment since impounding and this process is continuing at varying rates in each individual reservoir. The volume in the reservoirs has been reduced by between 25% at Roseires and 40% at Sennar and Khashm el Girba.

The relationships for Roseires and Sennar adopted for this study were supplied by MoI. The method employed for calculating varying reservoir area and volume for Jebel Aulia is also as reported in M&M1997. Meanwhile the Khashm el Girba reservoir characteristics are taken from the previous Long Term Power System Planning Study (Acres 1993).

In the light of the information currently available on likely sedimentation effects, future trends in reservoir capacity will be assumed for this study as:

1. At Jebel Aulia, the reservoir storage capacity will not be significantly reduced over the next 20 years.

2. At Roseires, reservoir sedimentation will continue at an average rate of 10 Mm^3/year over the next 10 years and 8 Mm^3/year for the 10 years after 2012.

3. At Sennar, sedimentation will not reduce the capacity of the reservoir significantly over the next 20 years (M&M1997).

4. At Khashm el Girba, roughly the existing storage capacity will be maintained by the current sediment flushing practices.

5. For proposed and yet to be completed reservoirs (such as Merowe) details of future reservoir characteristics are as presented in available detailed project reports.

4.3.6 Operating rules

Hydroelectric performance is determined not only by scheme design but also by the operating rules in force and, in the context of long-term planning, operation is conveniently defined in accordance with a variety of seasonal demand and reservoir rule curves.

The Roseires, Sennar and Jebel Aulia reservoirs provide seasonal regulation of river flows to meet the needs of flood control together with irrigation and electricity supply. Another constraint on reservoir operation is the need to preserve storage capacity by controlling reservoir siltation.

At Roseires this has dictated that the reservoir be held at minimum level each year until the bulk of the flood and entrained silt load has passed downstream, and then be filled at the very end of the flood season. Rules determining this operation have previously been reviewed in the context of the heightening of Roseires dam, and simulations for this study have now confirmed that they remain appropriate.

The reservoirs are currently operated between minimum and full supply levels as set out in Table 4.1. The filling rules adopted for the White and Blue Nile reservoirs are those reported in M&M1997 as modified in accordance with recent information from the MoI, and are outlined below.

Jebel Aulia:

The first filling of the dam starts on 1 July each year from MOL of 372.50 m, and continues for one month reaching a level of 376.50 m by the end of July. This level is held for one month until the peak flood of the Blue Nile has passed. Filling then continues, reaching a maximum level of 377.40 m by early October where it is held until the beginning of 'draw-down' during the last period in March. Drawdown continues until the end of June when the reservoir returns to MOL of 372.50 m.

Roseires and Sennar:

During the flood period July-August, Roseires is assumed to be held at the MOL of 467.60 m with Sennar held at 417.20 m. Filling of Roseires commences during the last week of August as the earliest date in accordance with the following:

a) At the last week of August if the flow from El Deim is below 350 Mm^3/day or has risen above 350 Mm^3/day and fell below that before the end of August.

b) After the end of August if the flow at El Deim reached 350 Mm^3/day and continued for three days.

c) On 26 September as the latest date if the river flows continued above 350 Mm^3/day.

Khashm El Girba

Initially a filling rule for Khashm el Girba reservoir was developed based on filling behaviour demonstrated in the reservoir level and inflow records for the period 1992 to 2001 which had been obtained from the MoI. Following the provision of further information by the MoI and then completion of the reservoir inflow record as described above, operating rules for use in this study have now been finalised, these being in outline as below.

Depending on whether the inflow has or has not increased to a defined value, reservoir filling commences towards the end of August or early September and is completed by the end of September.

From completion of filling until June, releases are made to satisfy irrigation demand and then, until the end of June, to suit energy demand while still meeting reduced irrigation requirements. These releases are made so that the reservoirs are empty at the end of June in anticipation of the arrival of increasing inflows.

The justification of additional hydroelectric plant may be greatly affected by considerations of reservoir operation. At existing sites much of the additional hydroelectric output will be generated in the flood season since most of the water available in the dry season can be fully utilised by the existing plant. It follows that any new plant at these sites will be operated predominantly at minimum reservoir level, and both plant design and future operation will be particularly sensitive to any changes to minimum levels as may be decided.

The Roseires and Sennar reservoir operating rules have accordingly being reviewed, as discussed with the NEC and MoI, to ensure that operation of the base system is reasonably optimal before considering future additions. In order for all comparisons to be made on a comparable basis, a set of guide-lines and procedures for reservoir operation have then been defined which in principle will remain unchanged for the duration of the study.

4.3.7 Irrigation Demand

Detailed below are the key assumptions made in estimating the existing seasonal irrigation demands and their forecast future growth. Average seasonal irrigation demand patterns have been adopted or modified from previous studies. All irrigation demand patterns represent gross abstractions, with no estimate of return flows from irrigation projects into the rivers having been made. This is a conservative approach to estimating these important components of the water balances, but is considered appropriate given the uncertainties in the irrigation demand data.

It is unclear which of the proposed irrigation projects, whether in new areas or as expansions of existing schemes, are directly dependent on the completion of specific water conservation projects. It is also unclear when the various conservation projects are likely to be completed. It has therefore been necessary to make broad-brush assumptions on these aspects, consistent with the Long-Term Strategy Report.

Expansion in demand and changes in the demand profiles on the Blue Nile are dependent on the completion of the heightening of the Roseires Dam or development of reservoir projects in Ethiopia. Later seasonal releases of flows from additional storage in Roseires or upstream will also impact in a similar way on water available to the Main Nile pump schemes where access to water is currently limited when river levels are low. Changes in Blue and Main Nile irrigation profiles are therefore also dependent on the heightening of Roseires, and these changes are assumed to develop over the next 25 years.

4.3.8 Existing and future irrigation schemes on the Blue Nile and Main Nile

Blue Nile

Blue Nile irrigation consists of the Gezira/Managil project that is gravity fed from Sennar reservoir and is otherwise divided into demand upstream between Roseires and Sennar and downstream between Sennar and Khartoum. Existing irrigation schemes upstream from Sennar comprise the pump-fed Rahad, El Suki, Abou Naama Sugar and North West Sugar projects as well as the public and private pump projects. Downstream from Sennar, pump schemes include Al Gnaid and Al Slait and Waha.

The M&M1997 Report developed 10-day water demands for many of the schemes with the assistance of the MoI in 1996. For the Al Gnaid and North West Sugar projects we have used demand profiles developed by Acres (1993). All these demand profiles are assumed not to have changed significantly in the intervening years.

Two demand patterns are used for Gezira-Managil. One pattern represents a normal year (4 in 5 year condition) with a wheat area of 400,000 feddans while the second pattern represents a dry year (1 in 5 year condition) with reduced wheat area of 70,000 feddans. The flood-flow condition characterised by the sum of July, August and September (JAS) flows is then used each year over the period of hydrological record to determine whether in that year demand will follow the normal or dry year pattern. The normal year pattern is assumed if the JAS flow is greater than the JAS value exceeded 80% of the time (the 80% exceedance probability). For the present study the demand patterns thus derived have been scaled to match the demands given in the Long-Term Strategy Report, so as to retain the important distinction between normal and dry-year demand.

Future expansion of irrigation demand on the Blue Nile will be based on development of the Rahad II, Kenana and South Dinder schemes in association with increased storage provided by raising the Roseires Dam or by upstream reservoir developments in Ethiopia. Estimates of additional Rahad and Kenana irrigation demand are based on those agreed with MoI and reported in M&M1997, but scaled down slightly to match the values given in the Long-Term Strategy Report. In the absence of detailed information on the South Dinder project, or indeed as to which crops are expected to be grown there, a generic seasonal crop-dominated monthly demand pattern (after Acres 1993) has been assumed. During years following the completion of Roseires heightening, it has been assumed that the peak period of pump scheme demand will lengthen ultimately through to April so as to exploit the additional water available. It has been assumed that there will be no additional intensification of demand in the Gezira/Managil Project.

Main Nile

The existing irrigation demand includes both public and private pump schemes. No detailed information on the locations of pump projects is currently available, and so we have estimated a spacial distribution of demand based on a map of irrigation areas provided by MoI (Topo Map S H 35). This map indicates that the demand is concentrated in two areas, one downstream of Shendi and the other between Merowe and Dongola. Based on relative land areas shown on the map we have assigned 40% of Main Nile demand upstream from Hassanab and the remainder to downstream of Merowe township. Upstream from Hassanab we have assumed that 61% of the demand occurs upstream from Saboloka. These estimates are based on the lengths of the various river reaches, assuming an orderly distribution of riverbank pumps. In the absence of information on crop types and detailed irrigation demand information we have assumed a representative dominant seasonal crop-demand profile (after Acres 1993). For this study we have assumed that future increases in irrigation demand from the Main Nile will take place in the existing areas and that expansion of demand will be tied to the heightening of Roseires Dam.

4.3.9 Irrigation demand modelling

For modelling purposes the Nile system has been divided into convenient river reaches as shown in the current RAPSO arrangement illustrated in Figure 4.1. Thus the following demands are used in the water balance analysis:

- Bahr el Jebel irrigation demand,
- White Nile irrigation demand upstream of Melut,
- White Nile irrigation demand downstream of Melut,
- Blue Nile upstream of Sennar,
- Gezira/Managil irrigation demand,
- Blue Nile irrigation demand (Sennar to Khartoum),
- Main Nile irrigation demand (Khartoum – Sabaloka),

- Main Nile irrigation demand (Sabaloka – Hassanab)
- Rumela irrigation demand,
- Khashm el Girba irrigation demand, and
- Main Nile irrigation demand (Hassanab – Dongola).

4.3.10 Total irrigation water requirements

In total the existing irrigation demand adopted for this study is an average of 14.45 MD m^3 per annum. This is similar to 1997-99 total irrigation estimates provided by the MoI and slightly lower than the often quoted irrigation demand of around 18.5 MD m^3 in The Water Resources of Sudan (1977). The average irrigation demand is projected to increase to 23.57 MD m^3 by 2012.

Short- and medium-term plans could see the area of irrigated land increase and irrigation demand grow by 1.47 MD m^3 from the Atbara river, 4.9 MD m^3 from the Blue Nile, 5.2 MD m^3 from the White Nile and 1.7 MD m^3 from the Main Nile. A summary of projected water requirements for the Sudan 2002 - 2012 is set out in Table 4.2, and a breakdown by area is given in Table 4.3.

Table 4.2 : Projected Water Requirements – Summary

Nile Tributary	Cultivated Area (1000 Feddans)		Water Requirement (Mm3)	
	2002	2012	2002	2012
The Blue Nile#	2112	3186	9050	11481
The White Nile	480	1067	2050	4968
Atbara River##	282	572	1270	2123
Main Nile	311	571	1300	1903
Reservoir Evap.			880	3170
Total	3185	5396	14450	23645
Other usage			1080	2500
Total			15530	26145*

Source: Long-Term Agricultural Strategy (2002-2027)

Table 4.3 : Projected Water Requirement by Area

Nile Tributary	Project	Cultivated Area (1000 Feddans)		Water Requirement (Mm3)	
		2002	2012	2002	2012
The Blue Nile Available Area is 6,271.5 million feddan	Gazira & Managel	1,500	1,800	6,100	6,100
	Rahad	220	280	1,100	1,100
	El Souky	62	78	300	300
	Public Pumps	175	270	780	1,200
	Private Pumps	40	150	140	490
	Al gnaid Sugar	40	43	280	301
	Sugar NW Sennar	35	45	250	315
	Abu Naama	20	30	70	105
	Al slait and Waha	20	40	30	70
	Kenana II & III		300		1,000
	Rahad II		150		500
	South Dinder				
Sub-Total		2,112	3,186	9,050	11,481
The White Nile Available Area is 1,791 million feddan	Public Pumps	280	350	1,000	1,250
	Private Pumps	60	160	210	538
	Kenana Sugar	90	90	580	613
	(Crops)	-14	-40		
	Hagar Asalaya Sugar	36	42	260	303
	White Nile Sugar		100		1,322
	Melut Sugar		75		663
	Mongalla Sugar		40		50
	Malakal Rice		20		80
	Pengco - Jonglei		50		90
	Others - South		100		180
Sub-Total		452	987	2,050	5,089
Atbara Available Area is 1,361 million	New Halfa	240	290	950	1,072
	New Halfa Sugar	42	42	320	320
	Upper Atbara		180		732
	(Sugar)		-60		
Sub-Total		282	452	1,270	2,124
The Main Nile	Public Projects	103	151	470	503
	Private Projects	208	420	730	1,400
Sub-Total		311	571	1,200	1,903

Source: Long-Term Agricultural Strategy (2002-2027)

4.3.11 Evaporation and Losses

It is important to note that, in accordance with the 1959 Nile Treaty, quantities of water lost to evaporation from reservoirs are deducted from Sudan's share of the Nile waters. Hence evaporation has to be particularly carefully considered in water-use planning.

Table 4.4 sets out the anticipated water losses to evaporation from the Blue Nile reservoirs (post Roseires heightening) and from existing and planned reservoirs on the Atbara river and Main Nile (Merowe reservoir).

Table 4.4: Annual evaporation from reservoirs

Nile Tributary	Project	Water Lost by Evaporation M m^3		
		2002	2012	2027
The Blue Nile	Roseires Reservoir	410	750 post heightening	750
	Sennar Reservoir	300	300	300
Atbara River	Girba Reservoir	170	170	170
	Upper Atbara Reservoir		400	400
The main Nile	Al Hamdab Reservoir		1550	1550
Total		880	3,170	3,170

Source: Long-Term Agricultural Strategy (2002-2027)

Profiles of the estimated monthly evaporation at each reservoir have been taken from previous studies where the detailed information is available. Where only annual net evaporation information is reported the amounts in each month have been estimated from published Climatic Normals (194070). Representative net evaporation profiles were estimated from climatic data collected by the Sudan Meteorological Department at Karima (northern Sudan), Wadi Medani (central Sudan) and Juba (southern Sudan) and these estimates have been applied to annual evaporation estimates at each project according to geographical location.

4.4 DATA FOR RAPSO MODELLING OF DAL

Considerable amounts of data are required for the modelling and various data items of particular relevance to Dal that have been employed are summarised below.

4.4.1 Period of hydrological record

For the Sudanese applications the period of record has been progressively extended and now runs for the 92-year period July 1912 to June 2005. As has been explained in the hydrology section, however, data for the Abay are currently available only for the 50-year period January 1953 to December 2003 and so, for the sake of consistency of approach, this shorter period has been adopted for all simulations performed for these studies. It is, however, noted that the driest and wettest years found in the 92-year period both occur prior to 1953.

4.4.2 Water inflows

The derivation of monthly flow series at various locations down the Abay has been described in the hydrology section. All of these monthly series have been converted to a 3-period-per-month basis by for each time step applying a factor derived from the gauging records at El Deim just downstream of the Ethiopian/Sudanese border. For this study the applicable El Deim flows are then taken as the sum of:

- the flows at the Karadobi site (as have been derived on the assumptions that throughout the 50-year period both a constant 77 m^3/s had been diverted from Lake Tana to supply the Beles scheme - now under construction - and also Lake Tana had been operated to provide the maximum possible firm outflow), and the
- incremental flows between Karadobi and Mandaya and between Mandaya and Border, and the
- return flow from Beles, assumed for the purposes of these simulations to be a constant 77 m^3/s, i.e unchanged from the flow diverted from Lake Tana..

The inflows to Kajbar are then derived by successively adding the downstream inflows, subtracting losses and modelling operation of the Roseiries, Sennar, Jebel Aulia, Kashm el Girba and Merowe reservoirs.

4.4.3 Reservoir levels

Although they would provide diurnal peaking, on a long-term basis both the Kajbar and Low Dal hydroelectric schemes are simulated effectively as run of river. The top water levels are respectively 213 and 201 m.

4.4.4 Electricity supply reliability

The standard (NEC) criterion for Sudanese planning is 95 per cent. For Ethiopia, however, the (EEPCO) planning criterion is 98 per cent and for the sake of consistency of approach this higher value is applied for all these pre-feasibility analyses. With 50 x12 x 3 = 1,800 time steps this allows a maximum of 36 failures to supply demand in full.

4.4.5 Reservoir characteristics and minimum operating levels

The level/area/volume characteristics employed and minimum operating levels assumed for the Dal reservoir alternatives are as have been presented in the hydrology section.

4.4.6 Evaporation losses

For each time step the evaporation loss is calculated by applying the relevant average calendar monthly net loss, as described in the hydrology section, to the simulated reservoir surface area.

4.4.7 Spillway characteristics

Until such time as spillways have been designed in detail it is assumed for the purposes of the simulations that all spill takes place from the relevant full-supply level.

4.4.8 Generating sets installed and allowances for plant maintenance

The plant installations and rated heads assumed for three Kajbar and one Low Dal alternatives are:

Kajbar:	4 x 50, 5 x 50 & 6 x 50 MW,	15 m
Low Dal	8 x 42.5 MW,	18 m

For all simulations it is assumed that every installed generating set in turn is taken out of service for maintenance for a period of 2 weeks each year, the weeks chosen being as far as possible during the dry season.

4.4.9 Penstocks and friction losses

For all Dal and Kajbar alternatives it has been assumed that each installed generating set would be supplied through a separate waterway (i.e. penstock), and for each simulation time step in turn the friction losses are derived as proportional to the square of the penstock flow, in each case the constant of proportionality having previously been derived on the assumption that a 0.5 m head loss would be experienced under rated conditions.

4.4.10 Turbine and generator characteristics

On the basis of data derived from earlier studies, the overall efficiencies are assumed to be constant at 88.53 per cent for Kajbar and 90.41 per cent for Low Dal.

4.4.11 Electricity demands

Also for the sake of consistency of approach with the Karadobi study, the electricity demands applied are seasonally invariant. In each RAPSO run therefore all electricity demands are raised and lowered by the same amounts until the desired reliability of supply is just achieved. Thus, although it is recognised that the value of power output is likely to be considerably higher in the summer than the winter, at this stage of study no attempt has been made to investigate the possible extent to which seasonal variation of output would be feasible. Similarly the effects and consequences of dry-season peaking operation have yet to be investigated. It is, however, clear that there would be considerable flexibility in the operating regimes that could be adopted.

4.4.12 Generation monthly rule levels

These reservoir control levels are optimised also within each program run, this being on the basis that supply is limited to meeting the demand as above whenever reservoir level is below the applicable control and otherwise, to the extent there is additional generating capacity available, supply is increased such as to bring the reservoir level down to the control.

4.4.13 Numbers of generating sets operated

In each time step the number of generating units operated is optimised such that the total electricity output as defined in the previous two subsections is provided with minimum total release.

4.4.14 Environmental releases

For all alternatives the same calendar-monthly minimum (environmental) releases have been simulated as have been described in the hydrology section. Because no releases for power generation are provided when the reservoir is below its minimum operating level and also the reservoir is never entirely emptied, all the simulations ensure that these environmental releases are maintained on a 100 per cent firm basis.

4.4.15 Tailwater characteristic

For all alternatives the same tailwater level/total discharge characteristic is employed as has been presented in the hydrology section.

4.5 RESULTS

As described below, for all alternatives various results are summarised in tabular and graphical forms at the end of this section.

4.5.1 Kajbar and Low Dal without any new Ethiopian scheme

The average energy outputs together with some other key indicators that have been calculated for the alternative Kajbar installations and the Low Dal scheme are presented in Table 4.5. Operation over the 3 hydrological years 2001-03 is illustrated graphically in Figures 4.4 and 4.5.

4.5.2 Kajbar and Low Dal with Mandaya

The flow commanded by Mandaya, which that scheme could regulate to a considerable extent, is some 44 per cent of the inflow to Kajbar, and further results allowing for such regulation by the Mandaya FSL 800 m alternative are presented in Table 4.6, with operation over the 3 hydrological years 2001-03 being illustrated graphically in Figures 4.6 and 4.7.

By comparing Table 4.6 with Table 4.5 it can be seen that the increased upstream regulation significantly reduces the spill and hence increases the energy outputs at both Kajbar and Low Dal, with the combined firm output being increased by around 11 per cent. The reductions in the spill peaks can also be seen by comparing Figures 4.6 and 4.7 with Figures 4.4 and 4.5.

Table 4.5 : Summary Results for Kajbar alternatives and Low Dal

Case	Average				Energy difference	98% firm output Kajbar + Low Dal
	Net head	Spill	Evapo-ation	Energy		
		(m3/s)		(GWh/a)	(%)	(GWh/a)
Kajbar 4x50MW	13.7	1168.9	3.7	1,126	-	2,607
Kajbar 5x50MW	13.7	1005.1	3.7	1,281	13.9	2,717
Kajbar 6x50MW	13.8	856.2	3.7	1,421	10.9	2,825
Low Dal, 8x42.5MW	18.3	844.1	27.5	1,943	-	-

Table 4.6 : Summary Results for Kajbar and Low Dal with Mandaya 800m FSL

Case	Average				Energy difference	98% firm output Kajbar + Low Dal
	Net head	Spill	Evapo-ation	Energy		
		(m3/s)		(GWh/a)	(%)	(GWh/a)
Kajbar 4x50MW	13.8	900.0	3.7	1,175	-	2,920
Kajbar 5x50MW	13.8	703.1	3.7	1,368	16.5	3,037
Kajbar 6x50MW	13.9	533.1	3.7	1,534	12.1	3,134
Low Dal, 8x42.5MW	18.4	528.4	27.5	2,088	-	-

Figure 4.4 : Operation of Kajbar with 5x50 MW

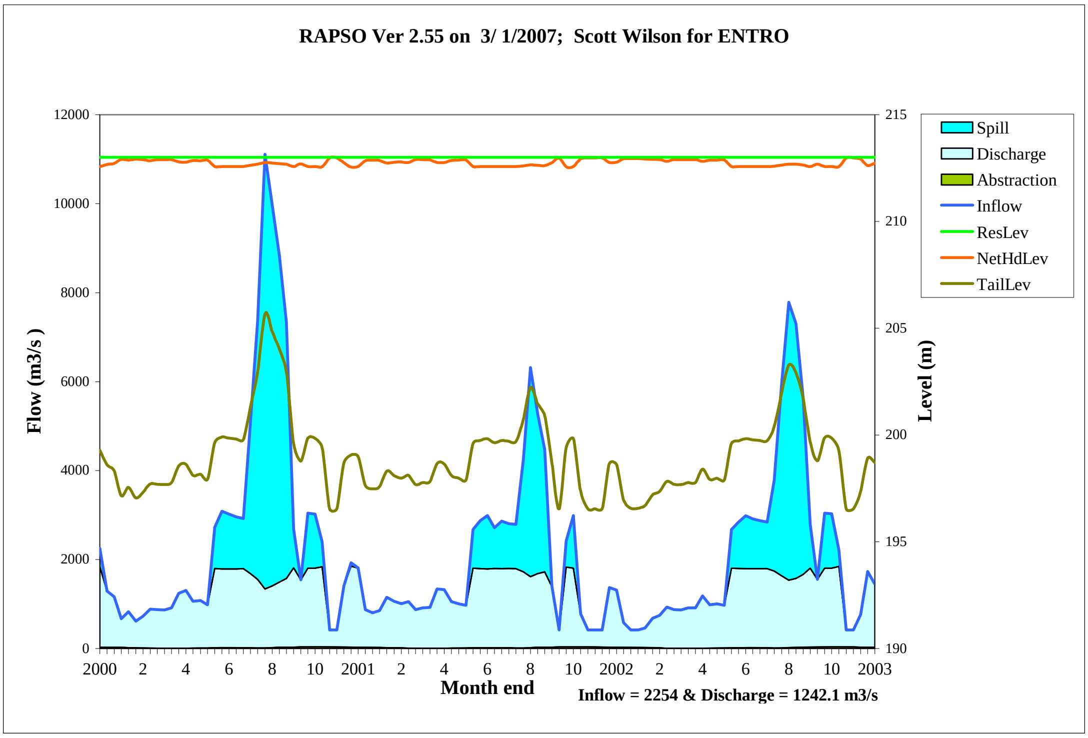


Figure 4.5 : Operation of Low Dal with 8x50 MW

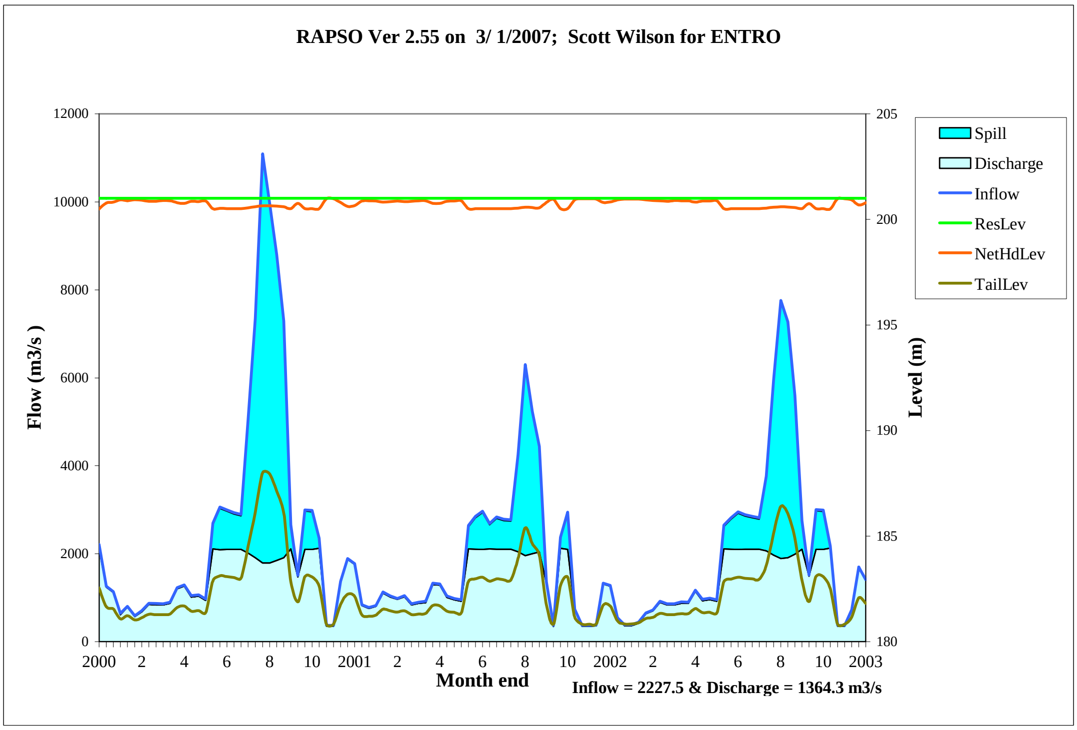


Figure 4.6 : Operation of Kajbar with 5x50 MW and Mandaya 800 m FSL

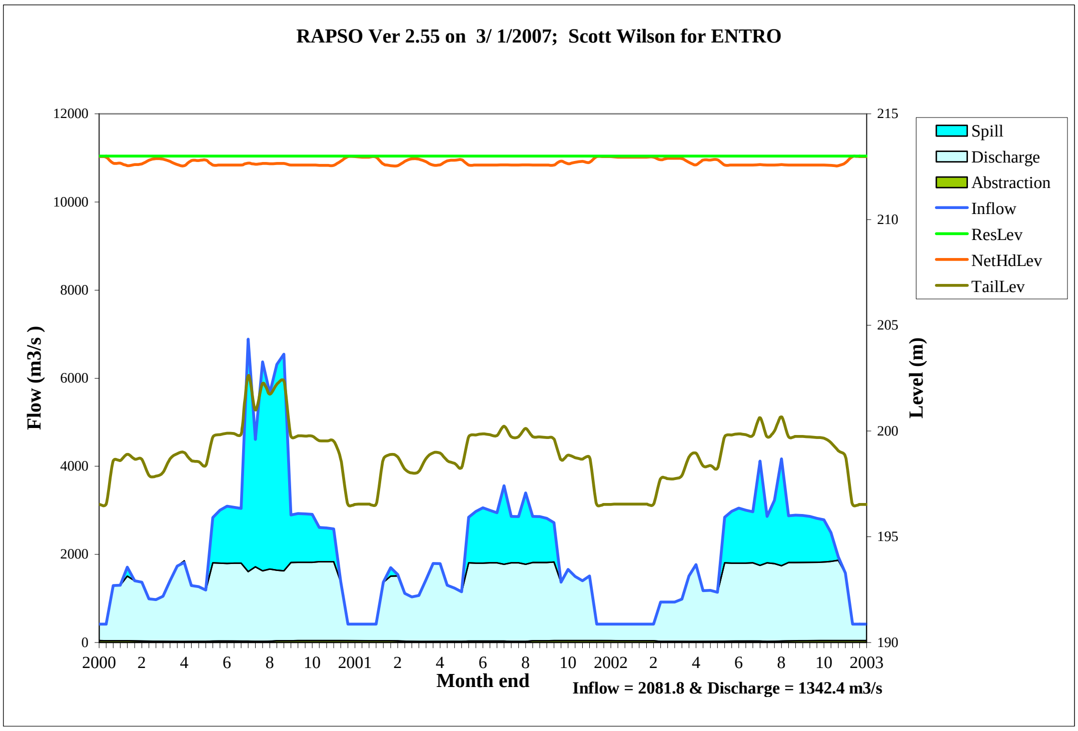
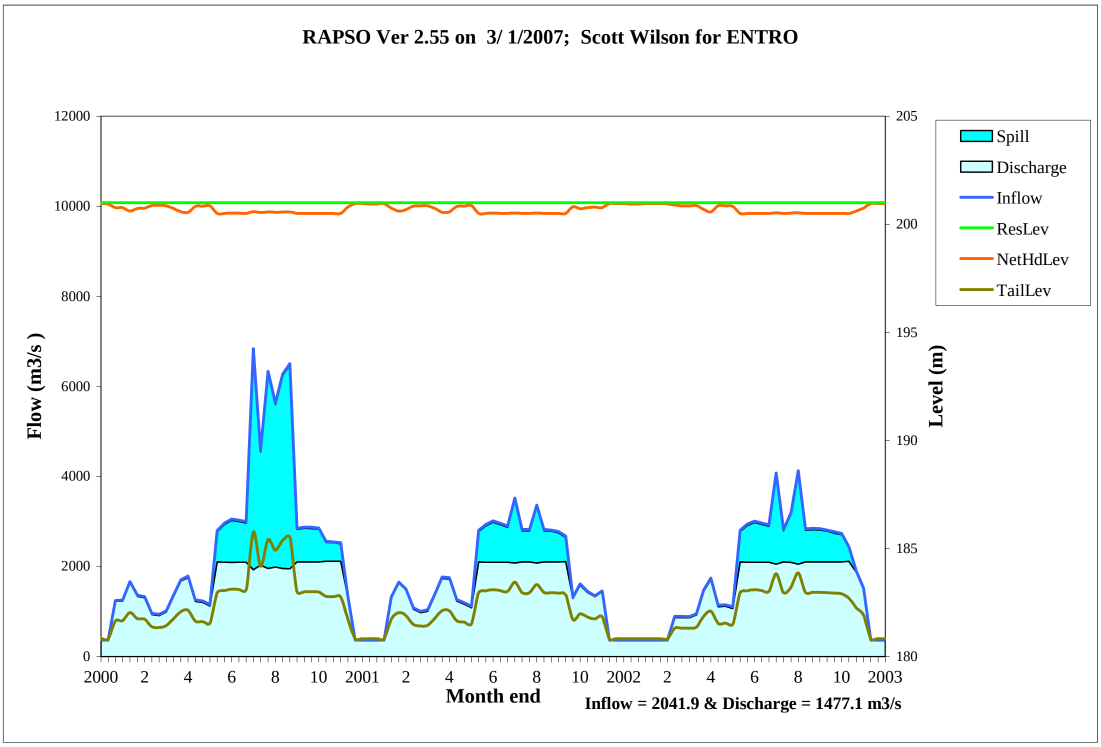


Figure 4.7 : Operation of Low Dal with 8x50 MW and Mandaya 800 m FSL



4.6 DOWNSTREAM IMPACTS IN EGYPT

The Low Dal and Kajbar projects are essentially run-of-river projects with very small storage reservoirs. As such there are no significant impacts associated with reservoir filling or operation and these have not been specifically studied.

4.7 REFERENCES

1. National Electricity Corporation, Building of Electricity Sector Database and Long-term Power System Planning Study, Interim Report No. 3, Volume 1 – Hydrology and Hydroelectric Power Plant.

2. Long-Term Agricultural Strategy (2002-2027). Report by the Water Resources Working Group, prepared by Dr Seif Eldin Hamad Abdalla, Ministry of Irrigation and Water Resources, Khartoum.

5. GEOLOGY

5.1 SITE LOCATION

Dal dam site is located on the Great Nile (See Figure 5.1). The site is at the Dal Cataract approximately 1340 km from Khartoum. To reach the site by road it is necessary to follow the main asphalted road from Khartoum to Abu Dom on the left bank of the Nile River, after crossing the Bayuda Desert. From Abu Dom it is necessary to turn left and follow the intermittently asphalted road to Dongola. This road follows the left bank of the Nile. Dongola is 10 hours from Khartoum, and is the first overnight stop on the journey. The next day you have to cross the Nile on the Dongola Ferry and proceed on the road North towards Wadi Halfa along the right bank of the Nile. The next overnight stop is at Abri, a regional centre. The trip from Dongola to Abri, via Kerma, takes another 8 hours of driving.

To reach Dal Dam Site from Abri you have to drive north on the Wadi Halfa road for about 35 km, and then having passed Ferka Mountain (topped with Nubian Sandstone branch left to follow a track to Sarkamatto village. It is about 75 minutes drive from Abri to Sarkamatto. A motor boat service connects Sarkamatto to Dal village across the Nile River. Dal village is at the top of the 5 km long Dal Cataract. The dam centreline is about 80 m downstream of the boat moorage. The centreline crosses an unnamed island through an ancient Assyrian ruin.

The coordinates of the dam alignment are approximately as follows:

Easting 30 deg 34 minutes, 14.76 seconds: Northing 20 degrees, 58 minutes 21.76 seconds.

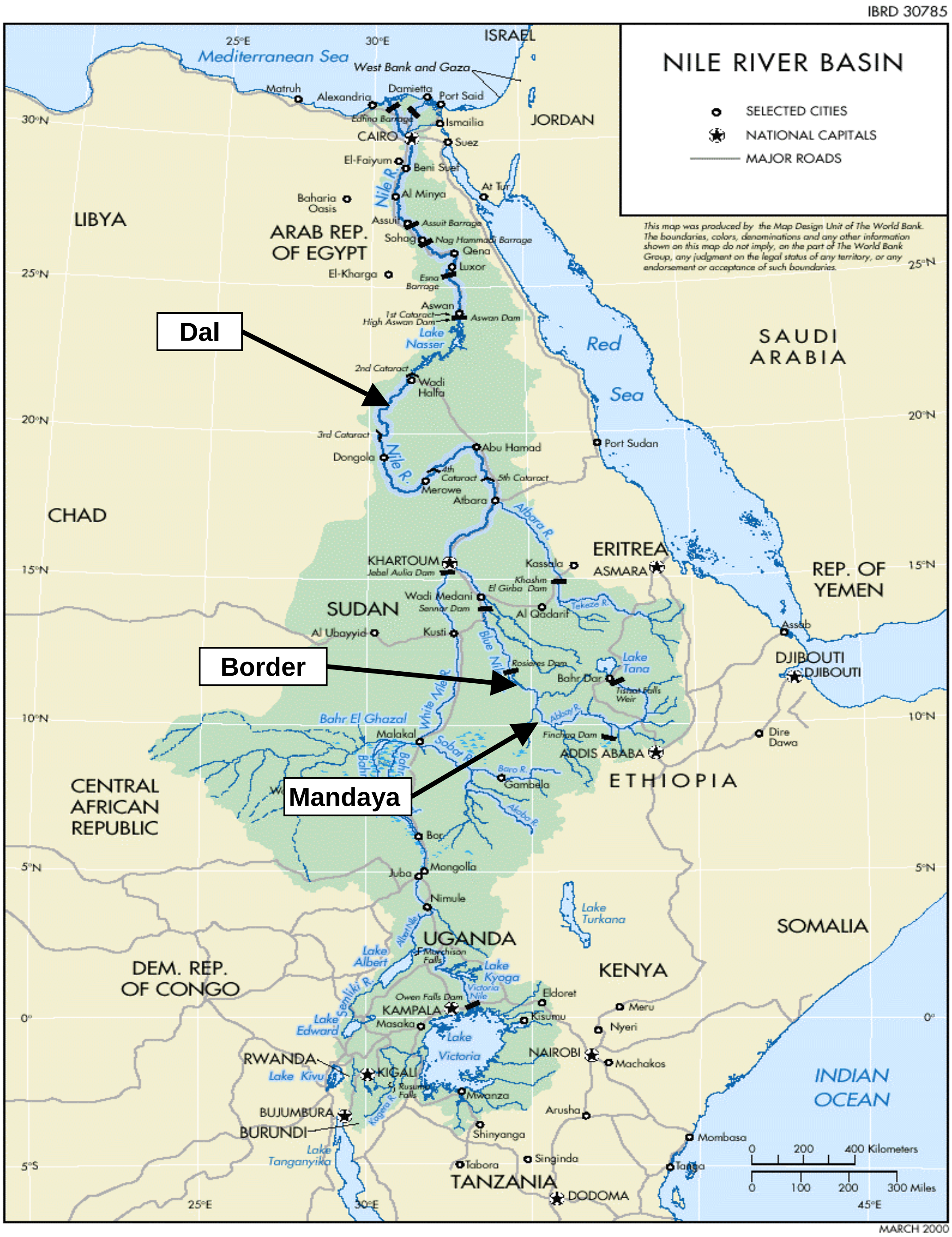
5.2 PRELIMINARY DESIGN OF THE DAL PROJECT

The Dal site is the most downstream of several Nile river hydropower sites presently under consideration in Sudan. Two options have been considered in the past for development of the Dal-Kagbar-Dongola reach of the Nile. These comprise: a high dam option at Dal with full supply level of El. 218 m which would flood upstream as far as Dongola or a cascade of two lower reservoirs at Dal and Kagbar which would operate as run-of-river projects. (In this case the full supply level at Dal would be 201 m.)

It is clear from the site visit that development of a high dam at Dal would lead to significant population displacement and social upheaval. In addition it would appear that the Dal reservoir would be extensive but relatively shallow potentially leading to excessive losses due to evaporation. Having regard to both of these factors it is considered that the most appropriate development of the Dal reach would comprise two low head run-of-river projects at Dal and Kagbar.

A preliminary dam design was presented in the Long-term Power System Plan (1993). In this document Drawing D38 indicates a 51 m high composite dam with minimum foundation level at 172 m and crest level of 223 m, and FSL 218 m, with crest length of 4200 m. The dam has a central concrete section with gated spillway in the river section, and an external power station offset to the left side of the spillway. The flanks of the dam are shown as earth or rockfill embankments but without any details. The presumed excavation depth to bedrock is shown as 3 m throughout.

Figure 5.1 : Location of Hydropower Project Sites



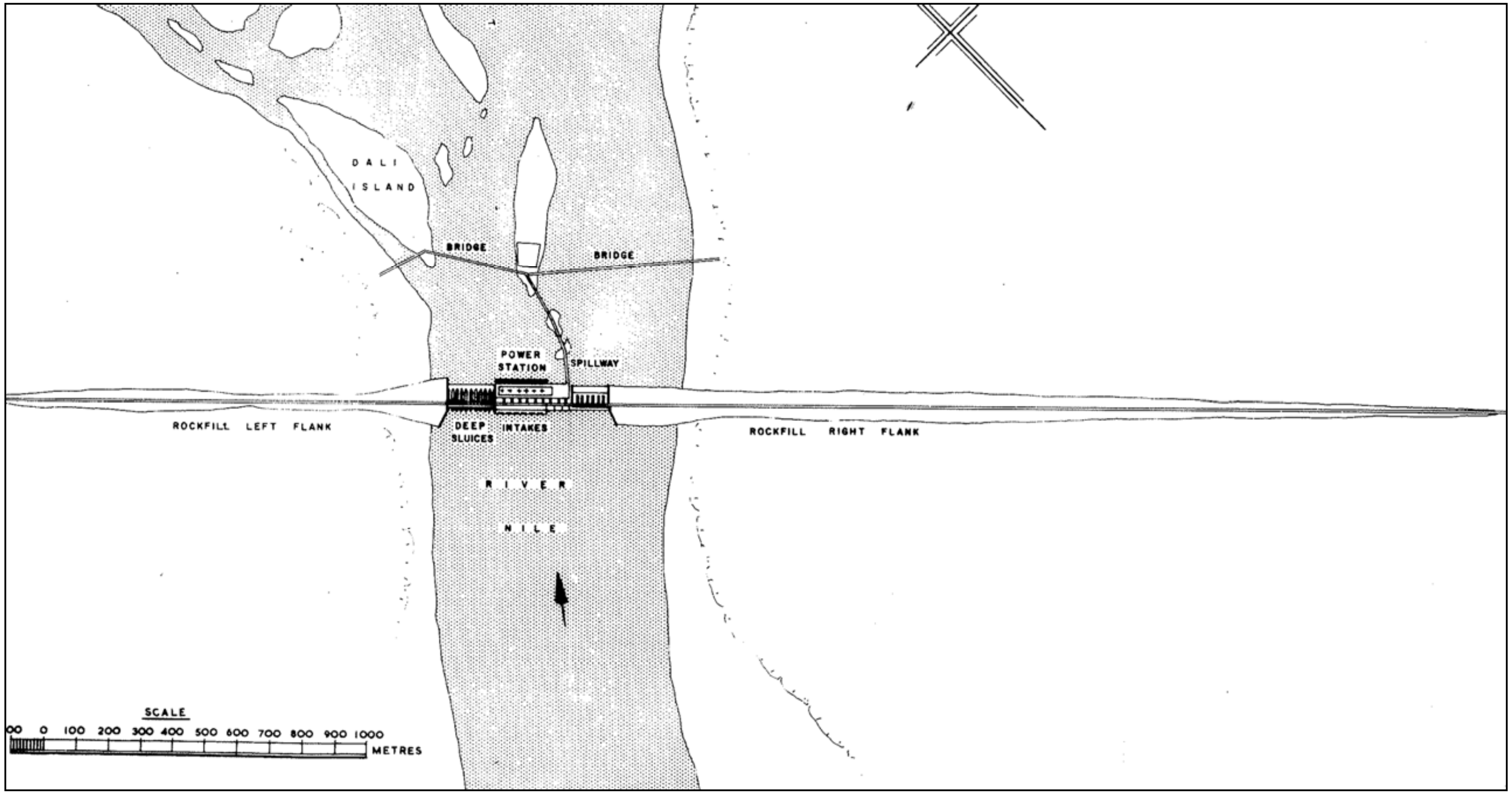
5.3 HISTORICAL BACKGROUND AND PREVIOUS WORK.

The Nile Waters Study (Coyne and Bellier et al, 1978), reported that work on the Dal dam site started in 1946 to 1952, but with no clear indication of the dam position. In 1947 cross sections were measured from Dongola to Wadi Halfa. Coyne and Bellier relied on these sections, Section 20 of the sequence was labelled Dal Cataract, and by scaling its position was fixed as just upstream of the first rocky section of the cataract. Therefore section 20 became the first of several Dal dam site centrelines. Subsequently section 20 was fixed at chainage 1334 km, measured downstream from Mogren in Khartoum. At section 20, according to a staff gauge, the river level was found to vary between seasonal limits of El. 178 m to 188 m above sea level.

Figure 5.2 shows the Dal project location and general arrangement as proposed in the Nile Waters Study. The following boxed extract is a geological description of the site taken directly from the Coyne and Bellier Report:

> **11.3 Description of Site**
>
> The mapping shows that the river channel above the cataract is divided by a string of small islands into two channels. The valley section indicates that the left hand channel is the major channel, and that the right hand channel is a flood channel, taking river flow at levels above 182.0 m approximately. The river valley on the right bank rises at a shallow slope to above level 220.0 m, while on the left bank the ground rises rather more steeply.
>
> Aerial reconnaissance of the site in March, 1978, indicated the buildup of banks of sediment on the left of the main channel, which could mean that the right hand channel is now the major one. The valley is well defined, with basement rocks exposed on the right bank, and a superficial deposit of wind sands obscuring the rock on the left bank.

Figure 5.2 : Dal Dam Site based on Nile Waters Study (1978).



(Note: The square on the central island is an Assyrian Ruin)

Dal site was again studied by Acres as part of the Long term planning study for NEC. The site was not visited but the centre line of the dam was relocated about 200 m downstream. The dam was shifted in order to place it on an island, so as to facilitate easier river diversion and splitting of the works. The revised alignment is shown on Figure 5.3 as the upstream centreline.

The Acres drawing shows a very long right flank and a short steep left flank. The real situation is opposite to this. The Acres design is vvery similar to the former Coyne and Bellier design shown in the Nile Waters Study. The flanks of the dam are proposed to be rockfill, with a central gated spillway giving full supply level at 218 m. The new spillway position is square on the ancient Assyrian ruin on the central island. The Acres report does not deal with the local geology of the site.

From this brief history it is apparent that the centre line chosen by Coyne and Bellier, and slightly moved by Acres, was arbitrary, being coincident with 'Section 20' of an old sequence of cross-sections surveyed at an arbitrary fixed interval. As Section 20 was the closest to Dal Cataract, this was assumed to be the dam site. However inspection of the Dal area as part of the present study, suggests no obvious preferential site, there are any number of possible centre lines. A topographic survey from river level to elevation 240 m, and along the 5 km reach of the Cataract would be necessary to fix the most advantageous centre line based on topography alone.

Scott Wilson in February 2007 defined an alternative centre line about 2.5 km downstream of the Acres alignment. This alternative takes advantage of several large rocky islands in the Nile channel, these would facilitate river diversion. In this report both the Acres and Scott Wilson centre lines were investigated, they are shown on Figure 5.3.

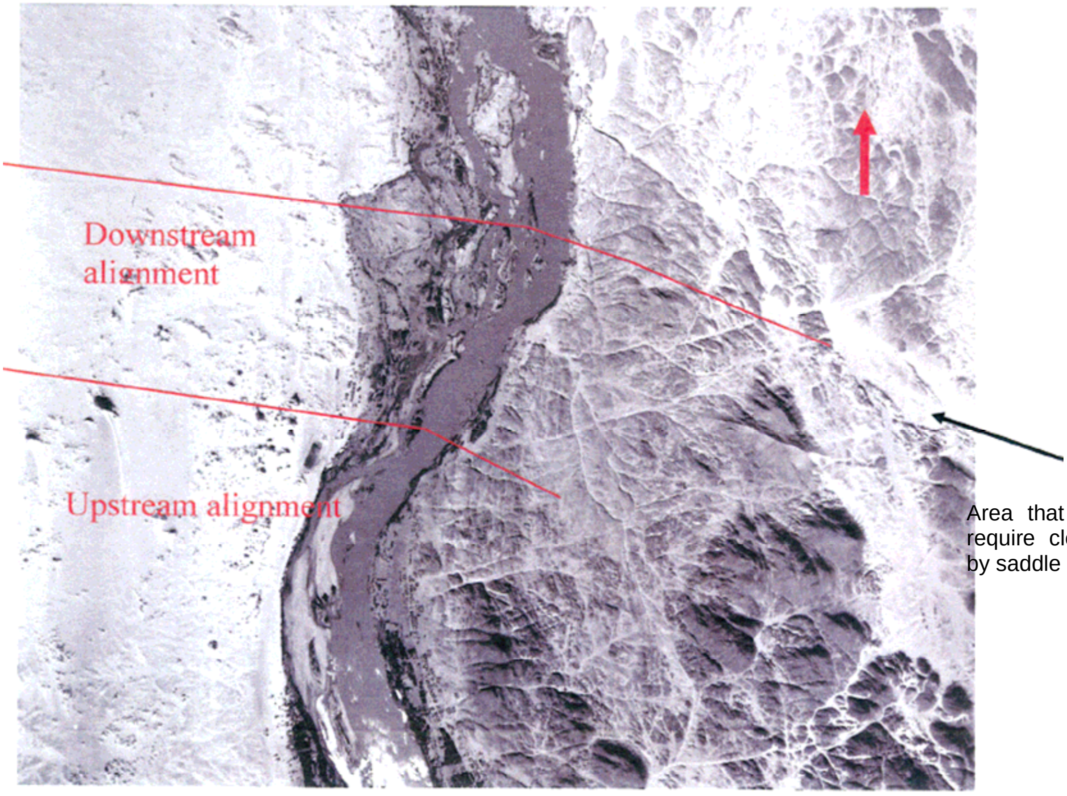
The Consultant EDF/Scott Wilson visited the site in November 2006 as part of the Preliminary Assessment of the project, and observations were included in the Inception Report, to ENTRO, dated 7th December 2006. The following extracts from page 18 and 20 of the Inception Report are pertinent to this study:

The site visit to the Dal-1 dam site in Sudan took place over the 4 day period 2nd November to 5th November 2006. ……………………………………………..

Observations were made of the foundation material for the dam as the bedrock at the site which is known as the Dal Cataract was exposed over a substantial area of the river banks and the abutments. Extensive rock exposures at the Dal site in Sudan are such that drilling is not considered necessary at pre-feasibility level.

As a result of the observations of the [Dal] *site during the visit, and in particular of the extensive outcrops of rock, both in the river bed and on the abutments, it was concluded that drilling of two investigation drill holes at the site would provide very little additional information. Accordingly, it is proposed that the investigations at the Dal site are confined to seismic refraction profiling to establish the depth of the interface between the surface soils and the underlying rock in those areas which have soil cover.*

Figure 5.3 : Dal Dam Upstream and Downstream Alignments Investigated



Area that may require closure by saddle dam

The pre-feasibility investigation of the two centre lines has been undertaken by regional geological mapping, previous investigations, surface mapping of the site, and interpretation of air photographs. This report presents the findings of these secondary investigations.

5.4 TOPOGRAPHIC MAPS, SECTIONS, AND AERIAL PHOTOGRAPHS.

No detailed topographic maps exist of the Dal dam site. An antiquated, untitled map of the Nile between Dongola and the Egyptian border is available, and this gives a sense of topography, but without any reliable contour information.

In 1947 cross sections were produced at systematic intervals for the entire Nile river downstream of Khartoum. One section at km1342.750 coincides approximately with the Coyne and Bellier centreline, this section indicates a dam site of 6 km width to attain a crest height of 224 m.

In 1985 a hydrographic survey of the Nile was carried out between Dongola and Wadi Halfa. Sheets 9 and 10 of a sequence of 19 sheets, give valuable information on the river bed morphology for all three centre lines.

Modern, 1 to 40,000 scale, air photos of the Nile River through Dal area are available. They were produced by the BKS and flown in January 1985. The key photos, which cover the dam area and nearby basin are Run 19, nos. 159 to 170.

This is a north to south run, with north at the bottom of each photograph. The stereographic trio of photos which cover the dam sites are nos. 165 to 167.

5.5 REGIONAL AND LOCAL GEOLOGY/GEOMORPHOLOGY.

5.5.1 Regional Geological Map and Related Studies

The first modern account of the geology of Sudan was provided by Whiteman (1971). Robertson Research International Group in collaboration with the Geological Research Authority of Sudan, GRAS (1988) produced a geological map of 1:1,000,000 scale. Recently GRAS (2004) introduced a 1:2,000,000 scale map. According to the explanation of this map Sudan may be considered of being made up of four major units, as shown below.

- The Basement Complex, comprising highly folded and metamorphosed ortho- and para-gneisses and schist intruded by syn-tectonic batholithic granite and gabbroic masses.
- Post-tectonic central igneous complexes of variable composition and age, some of which are in the form of well-developed ring complexes.
- Extensive Phanerozoic (Mesozoic) sedimentary cover of relatively un-deformed deposits such as the Nubian Sandstone.
- Cainozoic mid-plate basaltic volcanism which occurs as discrete volcanic centres and plateau basaltic flows associated with the Ethiopian Rift Valley magmatism.

The Dal site falls entirely within the Precambrian outcrop area. On the left side of the river these rocks are mainly covered by windblown sand, but on the right side there are large tracts of solid outcrop, separated by sand filled wadis.

A fragment of the published 1 to 1,000,000 scale geological map, which is centred on Dal site, is reproduced here as Figure 5.4. The map suggests that Dal site is underlain by three Precambrian rock Formations.

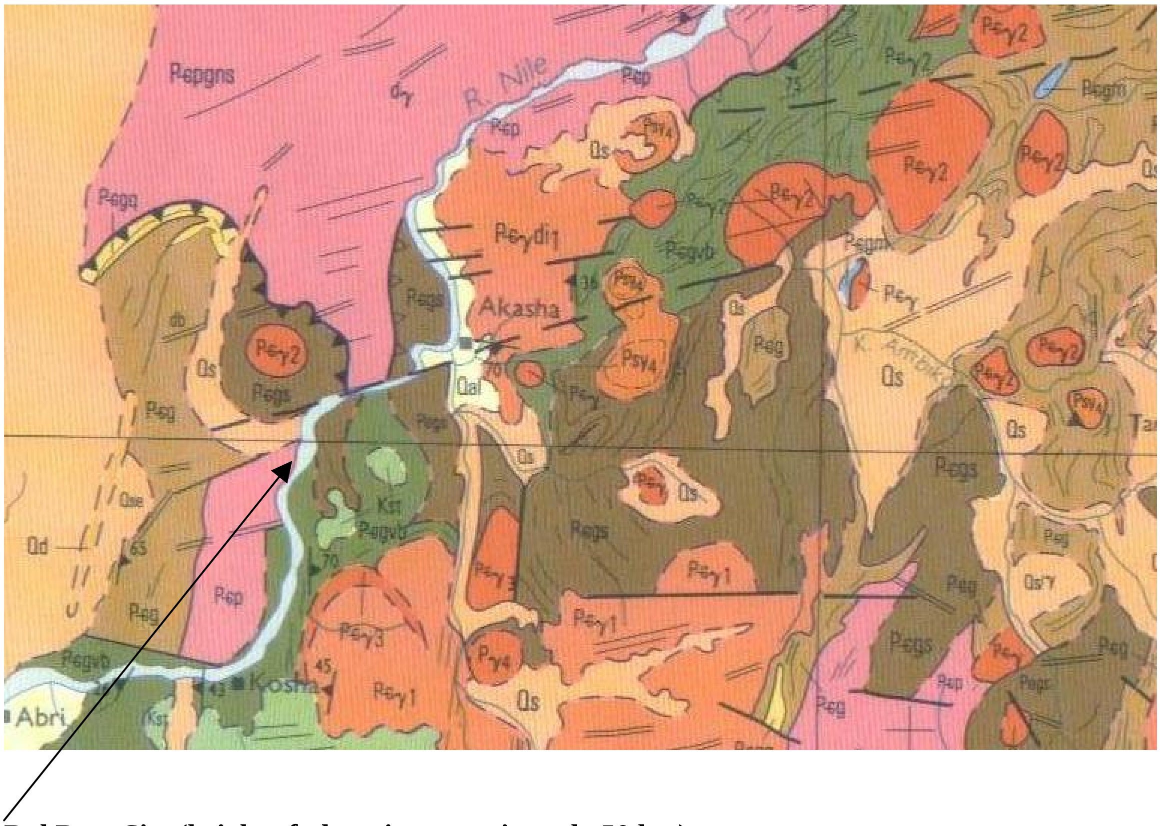
The left flank is shown as underlain by poorly exposed, undifferentiated metamorphic rocks of gneissic and migmatite varieties.

The south part of the right flank is shown as underlain meta-sediment and meta-andesite of green schist facies, meaning low-grade basic rock. This appears to be an interpretation by remote sensing, of a belt of well exposed, and macro foliated, black rock.

The northern part of the right flank is shown as being underlain by schist and phylites. Again this appears to be an interpretation of macro lineated pale rocks visible on remote images.

The regional foliation trend is suggested as north south. No lineaments or faults are shown within 3 km of the dam site. However a very large regional fault is shown 6 km north of the site, have vertical orientation and striking ENE-WSW.

Figure 5.4 : Regional Geological Map



Dal Dam Site (height of photo is approximately 50 km)

Qs — Active or recently active sand sheets and amalgamated dunes.

Kst — Undifferentiated fluviatile sandstones, siltstones and minor conglomerates of presumed Cretaceous age. Analysis of palaeoflora indicates Late Cretaceous age and unit may include Lower Tertiary sediments.

P€gvb — Andesitic-basaltic volcanic rocks.

N.B. P€gva, P€gvt and P€gvb have been subjected to varying degrees of greenschist facies metamorphism and are associated with derived volcano-clastic sediments.

P€p, P€pgns, P€pmg — P€p : Undifferentiated Proterozoic metamorphic rocks. P€pgns: gneissic areas; Pepmg: migmatites.

P€gs, P€gst — P€gs : metasedimentary units differentiated within P€g: slates, phyllites and low grade schists. P€gst: metasedimentary units differentiated within P€g: sandstones and conglomerates.

NB Qs is recent, Kst is Cretaceous, and the other units are of Precambrian age.

5.5.2 Regional Geomorphology

Not much literature is available on the geomorphology of Sudan. The drive from Khartoum to Dal indicates that over a long time period (post-Pliocene?), the Nile River has created a vast, almost flat pedeplain. The river appears to be close to perfect grade level, having an average slope of about 1 in 400. Cataracts are present at infrequent intervals, they represent resistant rock formations that have been graded almost flat by the river. Grades are slightly steeper in the cataracts, creating rapids and shoals.

The monotony of the pedeplain landscape is broken by inselbergs, and table-top mountains of more resistant geological formations. In the absence of rain, weathering is achieved by mechanical disintegration and ablation. The landscape can be divided into floodplain, rocky desert, stony desert, and sand desert. The floodplain consists of modern low terraces, and ancient high terraces of alluvium. The distribution of different types of desert is haphazard.

5.6 LOCAL GEOLOGY AND LOCAL GEOMORPHOLOGY

5.6.1 Local Geomorphology

Dal dam site is situated at the northern end of a south/north stretch of the Nile. A few kilometres north of the centreline the river bends abruptly to the north east, and then maintains that course. In the Dal stretch the river is following a north striking foliation trend and possibly a geological contact parallel to the foliation. At the northeast bend the river follows the major regional fault that was mentioned previously. The Dal cataract is carved out of resistant granite and gneissic granite rock.

The Nile appears to have migrated from west to east at Dal. The slopes to the west of the river are relatively flat and planed-off, with sparse hills of granite protruding from out of desert sands. On old elevated terrace of the Nile is found on the west side of the river, elevated levees and scatters of alluvial pebbles on top of windblown sand, indicate that the alluvial terrace is at least 1 km wide.

The landscape to the east of the Nile is very rocky, and steeper than that seen on the west side. This side of the Nile has only a narrow recent alluvial terrace, and it appears that the rocky outcrops are being undercut and steepened by gradual eastward migration of the river. Slopes rise steeply to 220m above sea level from the riverbed level of 173m, but then fall away into a system of sandy wadis. The wadis correspond to geological weaknesses that have been eroded away (dykes and faults) during “geological time”. The wadi network situated on the east side of the centre lines seems to extend south east, and then south west back to the river. They could define escape routes for the impounded water, and if they do, saddle dams will have to be constructed. This is all conjecture, as there are no topographic maps available.

5.6.2 Local Geological formations and Petrography

Geological mapping at the site confirmed the existence of four broad geological formations; namely the Massive Grey Granite, Sheared Granitoid Gneiss, Pink Sheared Syenite/Diorite Granitoid Gneiss, and Biotite Schist / Amphibolite Gneiss.

All these rocks are Precambrian in age, and they are all intruded by pegmatite, felsite, and basic dykes of indeterminate age. Fault zones were not seen in the field. The regional geological map was correct in demarcating three out of the four formations by remote sensing only, but incorrect in the generic description given to each division. Pegmatite and acidic dykes are ubiquitous across the entire mapped area.

Massive Grey Granite [PC1]

Outcrops of massive very coarse granite form the western islands in the cataract. Isolated domes of the same rock are found west of the site along the upstream centreline especially. The rock is composed of alkali feldspar, biotite and quartz, with minor accessory minerals. Xenoliths are common and they demonstrate the intrusive origin of this rock type. Several samples of granite rock were taken close to the centreline and submitted to the International University of Khartoum for petrographic analysis.

The typical rock mass condition, as seen in the scoured, river section is as follows: the rock is unweathered, and hard to extremely hard with no visible foliation. The rock is geomechanically massive with estimated UCS in the range 200 to 250 MPa.

Joint sets are not well developed, many outcrops seem unjointed. Orthogonal jointing is sometimes evident. Away from the river section outcrops are only found as exfoliated domes and pavements. Such outcrops give the impression of almost flawless rock, but this is a deceptive and biased sample of the bedrock, as there may be hidden zones of weaker rock buried by sand.

Sheared Granitoid Gneiss [PC2]

This is the sheared equivalent of the previous rock type. This rock forms the eastern islands of the cataract, and outcrops along the entire flank of the downstream centreline. The shearing is intense, so the grain size is reduced to medium, and typically there is seen a cataclastic foliated texture. The foliation is always striking north south with 40 to 45 degree dip towards the west, or west northwest. Weathering accentuates the foliation and in places the slightly weathered rock mass appears to be more schistose than gneissose. The petrography confirms a granitic composition, but metamorphism has resulted in alignment of mica grains, and other elongated minerals.

The contact between the massive granite and the sheared gneissic equivalent appears to be purely structural. The contact may be a major fault. Such fault might have some control the alignment of the Nile through the Dal cataract.

The contact of the sheared gneissic granite with the pink syenite diorite granitoid gneiss is not clear; an intervening wadi might suggest a fault contact.

The typical rock mass condition of the sheared gneissic granite, as seen in the river section, is as follows: the rock is slightly weathered and hard or medium hard with intense foliation. The rock is geomechanically fissile with estimated UCS in the range 50 to 150MPa, depending on foliation intensity.

One joint set is dominant, that one being parallel to the foliation, such joints are smooth and continuous with soft mineralized filling. Other joints and fractures tend to be randomly orientated (Appendix 5.1). Joint spacing is very variable, the rock mass could be defined as slabby.

Pink Sheared Syenite/Diorite Granitoid Gneiss [PC5]

The typical rock, when it is unweathered consists of medium grained pink, to brick red, speckled green, massive or foliated epidote-rich, diorite or syenite gneiss. A weak to very pronounced foliation is present with the usual north / south strike. The bright colour of this rock distinguish it clearly from other granitoid rock types.

Outcrops of this rock mass type are found along the upper part of the right flank of the upstream centreline. The typical rock mass condition is as follows: the rock is slightly to moderately weathered and foliated with bright pink, or brick red colour. Slightly weathered rock has estimated UCS in the range 100 to 150MPa.

The rock mass is usually closely jointed or medium jointed, most joints and fractures are formed by decomposed foliation planes (see Appendix 5.2), the rock mass weathers into small jagged and elongated pieces.

Biotite Schist / Amphibolite Gneiss and minor Metasediment [PC3, 4]

The typical rock, when it is unweathered consists of medium to fine grained black or grey, uniform schistose or gneissose biotite hornblende gneiss or schist [PC3], with quartz veins along certain foliation planes. A pronounced foliation is present with the usual north / south strike, and 40 to 45 degree dip towards the west. The rock is the metamorphosed equivalent of a basic volcanic rock, or intrusion.

Outcrops of this rock mass type are found only at the bottom of the right flank of the upstream centreline. The typical rock mass condition is as follows: the rock is fresh or slightly weathered, with perfect and pervasive foliation, to give a dark, slaty type of material. Slightly weathered rock has an estimated UCS in the range 100 to 200MPa.

The rock mass is usually closely jointed or medium jointed, most joints\and fractures are formed by foliation planes that have been parted by stress relief.

Some minor outcrops of metasediment and meta-quartzite [PC4] were found on the west side of the amphibolite gneiss outcrop area. They may extend under the main river channel at the upper centreline. They appear to lie conformably above the underlying amphibolite gneisses.

5.7 MINERAL RESOURCES IN THE DAM BASIN

Gold used to be mined in this area in the early 19^{th} Century, but there are no existing mining operations.

5.8 RESULTS OF SITE INVESTIGATIONS

5.8.1 Geological map and longitudinal section

A geological map of the site is presented as Drawing D2. The map is based on air photo interpretation and detailed geological mapping performed at, and between, 101 way-points defined by GPS.

Longitudinal geological sections through the two dam centre line are presented as Drawings D3 and D4. The sections are based on GPS coordinates and elevations. The section shows outcrops, rock types and assumed depths of alluvium.

5.8.2 Joint Surveys

No joint line-surveys were carried out because of the great variability of jointing from outcrop to outcrop. At each way-point the main joint sets were identified by measuring one joint from each set present. This gives a reasonable sample of the joint population across the entire site. The joint data in relation to way point location, coordinates and rock type are given on a spreadsheet in Appendix 5.2, along with DIPS plots of stereographic data, such as scatter diagrams, contoured plots of poles and main planes plot. The foliation planes are very dominant except west of the river. They create slabby and even slatey rock masses with foliation planes having low frictional-properties. West of the river the exposed rock masses are massive with joints having little impact on rock mass strength properties.

5.9 GEOMECHANICAL PROPERTIES OF FOUNDATION ROCKS

The geo-mechanical properties are described in Appendix 5.4. (after Professor T. Nurallah, of International University of Khartoum, who was part of the site investigative team).

5.10 RESERVOIR STABILITY AND LEAKAGE

Reservoir Side Slope Stability.

The dam basin is so flat there is no risk of side slope instability for either dam centre line.

Reservoir Seepage

The dam site is extremely flat compared to normal dam sites. The topography of both flanks is broken due to differential weathering along weakness planes like dykes and fault zones. The flanks rise very gradually and then fall away into wadis or low flat areas of windblown sand. There is no topographic mapping available. Two GPS's were used but these show errors of 0 to 12m on elevation. Consequently it is impossible to define the precise width of the dam on either centreline. The topography assessed by the naked eye, suggests that a Full Supply Level of 218m may be impractical as it would require construction of numerous saddle dams to impound water (Drawing D3 and D4). The basin waters would otherwise leak through these saddles or else seep through superficial layers of sand and disintegrated rock. The extent of this problem can only be assessed after a detailed topographic survey has been carried out.

The foundations rocks on the west side of each centre line are quite massive and in all likelihood systematic grouting of rock foundations to prevent seepage through the dam would not be needed. Contrarily the rocks on the east side of the river are highly sheared and intersected by numerous dykes and fault zones. These rock masses are prone to mechanical disintegration. Systematic grouting of these rocks would be needed to prevent seepage through rock below the right flank of the dam, whichever centreline was chosen.

5.11 CONSTRUCTION MATERIALS

5.11.1 Rock-fill Material

There are abundant resources for rock fill as detailed in the next section.

5.11.2 Coarse aggregate

High quality concrete aggregate and rockfill material, could be derived from the rock units having maximum mass strength (massive granite on west side of river).

Granite and granitic gneiss may contain potentially alkali silica reactive components such as opal and microcrystalline quartz. It is worth mentioning that Tilib (1992), Tilib (2002) and Tilib (2005) investigated some granites and granitic gneisses, some which have been and are being used as concrete aggregate for the Merowe dam project on the Nile. It was found that these rocks are weakly alkali reactive. They did show some reaction with the cement alkalis but this reaction was not accompanied by excessive expansion. In the petrographic examination of Merowe samples small amounts of potentially alkali silica reactive constituents were found present e.g. highly strained quartz, microcrystalline quartz and vein lets filled by microcrystalline silica

Two possible quarry sites are shown on Drawing D2.

5.11.3 Sand

Large quantities of windblown sand are available from the west side of the dam. The suitability of such sand will have to be determined by laboratory testing. If they are not up to specifications then sand will have to be obtained by crushing rock from the chosen quarry site.

5.11.4 Impermeable and Semi permeable soils

Significant alluvial clay deposits may be found in the high alluvial terrace on the west side of the river, which was photographed at way point 73. These materials could be used for an impermeable core within an earth embankment. The available reserves of clay soil are not known, and would have to be assessed during the feasibility investigation.

The alluvial floodplain deposits found adjacent to the west bank of the Nile might provide an unlimited source of random fill for an earth embankment. The average grain size of such material would be borderline between silt and very fine sand, meaning poor workability. This would have to be further investigated during the feasibility stage.

5.11.5 Pozzolan material

The term pozzolan is used for all siliceous and aluminous material that in itself possesses little or no cementitious properties but will, in finely divided form, and in the presence moisture at ordinary temperatures, react chemically with calcium hydroxide produced during hydration of Portland cement, to form stable compounds possessing cementitious properties (ASTM C-125). The contribution of a pozzolan to the strength of concrete is in the formation of hydration products that are essentially similar to those produced by hydration of Portland cement.

Class N-raw natural pozzolans consist of such materials as diatomaceous earths, opaline cherts and shale, tuffs and volcanic ashes or pumices. Pozzolans are used to improve or modify one or more properties of fresh or hardened concrete. It may be used for example to reduce heat of hydration in mass concrete and to minimize the risk of damage caused by alkali silica reactive aggregate (ASTM C-441).

Bayuda volcanic field

Natural pozzolan and volcanic ash are known to be available in the volcanic field of the Bayuda desert. The Bayuda volcanic field lies in the northern part of the Bayuda desert within the area covered by the Sudan Survey Topographic Sheet 45-F (Merowe) on 1:250000 scale about 80 km east of Merowe. The volcanic field is 48 km long and 11 km wide. This volcanic field may be the source of scoria (pumice) and volcanic ash in an amorphous state. Permanent wells at Sani and Abu Khorit form convenient site for exploration of the field and could be reached from Merowe. The preservation of primary volcanic landforms in Bayuda field according to Dawod (personal communication, 2007) indicates that the volcanic activity was geologically recent.

5.12 GEOTECHNICAL EVALUATION OF THE DAMSITE AND RECOMMENDATIONS FOR FURTHER WORK IN THE FEASIBLITY STAGE.

Position of centreline.

The optimum centreline alignment can only be determined after a full topographic survey. This would be a top priority for the Feasibility study. Based on the GPS data the upstream centreline appears to be better than the downstream option as the flanks are steeper. However, it is possible that a detailed topographic survey would allow other potential centre lines to be identified.

From a geotechnical perspective the upstream centreline may be the better option, as the alluvium may be less thick and narrower than the downstream option. However this has to be confirmed by drilling and seismic investigations during the feasibility investigation.

The foundation rocks at the downstream centreline may be better than those at the upstream alternative. The latter may intersect weaker schists and amphibolites in the deep part of the river channel, whereas the downstream alternative appears to be founded on granitoid rocks throughout.

Full Supply Level.

The maximum FSL of the dam is dependent mainly on topographic constraints. There are low lying areas adjacent to the central valley and these may necessitate several saddle dams to retain the basin at FSL 218m. Again: this has to be confirmed by topographic survey. The generally flat landscape might be better suited to the low level option mentioned earlier.

Type of structure.

The geology, geomorphology and topography of the Dal site and Merowe Dam are quite similar. Therefore a similar design might be utilized at Dal. This would mean long rock fill or earth fill embankments on either flank with concrete facing or clay core cut off depending on availability of earth materials. These two embankments, for an FSL of 218 m, would have a combined length of up to 4 km, with additional lengths of saddle embankments. The central part of the dam would comprise a 1 km long, concrete spillway and adjacent powerhouse. River diversion would be by way of an open channel, through the western abandoned river channels. Central islands would facilitate such a method of diversion.

Depth of Alluvium.

The depth of alluvium at the dam site is crucial to the cost effectiveness of the Dal dam site. Original assessments suggested a surfeit of rock outcrops implying only minimal deposits of alluvium and therefore only minimal excavation depths and cut off requirements. The maximum depth of alluvium at Merowe Dam is 24m. The Dal and Merowe sites are superficially similar in geological, geomorphologic, and hydrologic aspects, and therefore one might assume the maximum depth of alluvium to be 24m or more at Dal. It is reasonable to assume that as the river approaches base grade level the alluvium depth increases being maximal at the delta mouth. The exception to this rule would be if Dal cataract represents a local interruption to grade level, in this case the river grade at Dal would have to be significantly steeper than at Merowe, a faster moving river would result in more efficient sediment transport and therefore thinner accumulations of alluvium.

A striking feature of both Dal centre lines is the rock slope that forms each right flank, and the very narrow alluvial terrace at the base of each rock slope, but the depth of these narrow terraces is unknown. Both centrelines have a single deep active river channel on the eastern side of the river section. The depth of alluvium below this channel is unknown. Both centrelines have rocky islands in the centre and west side of the active channel, and outcrops are quite frequent, this gives the favourable impression of shallow alluvium and good foundation conditions. However it is possible that the outcrops and islands are buried pinnacles separated by deep trenches filled with alluvium.

On the west flank of the downstream centreline there is evidence of a wide elevated alluvial terrace with some clay deposits infilling abandoned channels. This elevated terrace may be up to 24m deep as at Merowe. Such terrace must be present on the west flank of the upstream centreline but it is not evident from field inspections. It is plausible that the cross section, perpendicular to the river, of the total alluvial infill, is the same for both centrelines.

One of the primary aims of the full feasibility investigation will be to investigate the true depth of the alluvium by seismic and diamond drilling methods. For preliminary cost estimates and comparison of different dam sites it should be assumed that the maximum depth of alluvium is between 15 - 25m, but with very irregular base profiles interrupted by granite pinnacles.

Dam Foundations (i) Downstream Centreline

River section.

For the downstream centreline the flat, central, river section, including ephemeral channels, is 1850m wide. At time of survey the river level was about 181m, and according to the hydrographic survey by Livesey Henderson , Binnie & Partners, the deepest part of the river channel is at elevation 158.7m, giving maximum water depth of 22.3m. This depth may be a crude indication of the maximum possible thickness of the alluvial infill. In the interpreted section (Drawing D3) the depth of alluvium is shown as 0 to 15m, 7.5m on average, with possibility of localised deeper trenches. The alluvium will comprise silt and very fine sand with localised layers and lens of pebble bed and erratic large boulders.

The bedrock on the west side of the river section is massive granite of very high quality and this would be ideal for the overspill section of the concrete wall. The unconfined uniaxial strength of this rock material is high, generally above 200MPa, and jointing is poorly developed. The bedrock below the east side of the river section is likely to be sheared granitoid gneiss with westward dipping foliation planes. These rocks are weaker than the massive granites but nevertheless provide high quality foundations in unweathered state. The easterly islands of gneissic rock stand tall above the river level and obviously have provided a potent barrier against river erosion for countless centuries. The feasibility investigation of this part of the dam will require target drilling and seismic profiling, to determine the depth of the alluvium, and to confirm the high quality of the bedrock. Five boreholes should be drilled to depth of 15m into unweathered rock. Lugeon testing will be required to assess the rock mass permeability.

Left Flank.

The left flank of the downstream centreline is at least 2 km long. It has two foundation elements: lower slope and upper slope.

The lower slope is a flat slightly elevated alluvial terrace with infrequent rock pinnacles outcropping as pavements on the surface. Mostly the alluvial terrace is buried by recent windblown sands. Evidence for the alluvial terrace is threefold:

- Visibility on air photos.
- Elevated 'outcrops' of calcified clay with calcified rootlets
- Scatter of rounded pebbles that can only be exhumed by wind ablation acting on alluvial sediments.

In the interpreted section (Drawing D3) the depth of alluvium in the elevated terrace is shown as 0 to 15m, 10m on average, with possibility of localised deeper trenches. The alluvium will comprise silt and very fine sand with localised layers and lens of abandoned channel clay deposits. The bedrock is massive granite of very high quality. The feasibility investigation of this part of the dam will require target drilling and seismic profiling as explained previously, three boreholes should be drilled to depth of 10m into slightly or unweathered rock.

The upper slope is also rather flat. It is at least 1 km long. There are seen scattered inselbergs of massive exfoliated granite separated by sloughs of wind blown sand. The section suggests windblown sand deposits of 0 to 2 m thick. The feasibility investigation of this part of the dam will require trenching to expose the rock sections beneath the blown sand.

Right Flank.

The right flank of this centre line is 300 m long. The lower part of the flank crosses a 150 m wide, elevated alluvial terrace. In the interpreted section (Drawing D3) the depth of alluvium in the elevated terrace is shown as 0 to 25 m deep 20 m, 15 m on average. The alluvium will comprise silt and very fine sand with localised layers and lens of abandoned channel clay deposits. The bedrock is likely to be sheared gneiss of high quality. The feasibility investigation of this part of the dam will require target drilling and seismic profiling as explained previously, one or two boreholes should be drilled to depth of 10 m into slightly or unweathered rock.

The upper part of the flank is rock slope devoid of soil cover. The rock is slightly, to moderately weathered sheared granitoid gneiss intruded by numerous dykes. The rock exposures are splintery due to the pronounced foliation. At depth of 2 to 5 m the rock mass is expected to be unweathered and of high quality. The feasibility investigation of this part of the dam will require one borehole should be drilled to depth of 10 m into slightly or unweathered rock, with Lugeon tests to determine the rock mass permeability. Trenches or pits should be excavated to investigate dykes and other structural features.

If saddle dams are required similar geological conditions will pertain.

Injection grouting.

One of the important aspects of the foundation drilling is to determine rock mass permeability by Lugeon testing. Due to the affect of well defined foliation joints, and stress relief exfoliation of the rock masses near surface, the right flank and east half of the river section, may require curtain grouting to prevent seepage under the embankment. Conversely the unweathered massive granite underlying the western half of the dam may be impermeable.

Diversion.

The river diversion will be achieved through a +-500 m wide, diversion channel situated on the left side of the river section, taking advantage of the ephemeral channel system. The channel will be excavated down to bed rock.

Dam Foundations (ii) Upstream Centreline

River section.

For the upstream centreline the flat, central, river section, including ephemeral channels, is 1450 m wide. At time of survey the river level was about 182m, and according to the hydrographic survey by Livesey Henderson , Binnie & Partners, the deepest part of the river channel is at elevation 162 m, giving maximum water depth of 20 m. As mentioned previously this water depth may provide a crude indication of the maximum possible thickness of the alluvial infill. In the interpreted section (Drawing D4) the depth of alluvium is shown as 0 to 15 m, 7.5 m on average. The alluvium will comprise silt and very fine sand with localised layers and lens of pebble bed and erratic large boulders. Comparing the two sections; the alluvium at the upstream centreline is reduced in comparison to the downstream alternative. Possibly the alluvium is underestimated in Drawing D4. The deep part of the active river channel may not bottom on rock as illustrated, but rather on sediment, with possibility of a local deep trench filled with sand and pebble beds.

The bedrock on the west side of the river section is massive granite similar to that described for the downstream centreline. The bedrock below the main active channel on east side of the river section is likely to be relatively weak metasediment, biotite schist, and amphibolite gneiss as interpreted from Drawing D2, with 40 to 45 degree- westward dipping foliation planes and schistosity. The central island of sheared gneiss delimits the lateral extent of the weaker foundation rocks. The feasibility investigation of this part of the dam will require target drilling and seismic profiling, to determine the true depth of the alluvium, and to confirm the variable quality of the bedrock, and in particular the distribution of the foreseen metasediments and schists. Six boreholes should be drilled to depth of 25 m into unweathered rock. Lugeon testing will be required to assess the rock mass permeability.

Left Flank.

The left flank of the upstream centreline is at least 2 km long. In the interpreted section (Drawing D4) there is no alluvium shown. There is no evidence of an elevated alluvial terrace such as seen at the downstream centreline. Possibly the terrace exists but is well buried beneath wind blown sands. It is also possible that an old buried river channel is present west of section 6b.

As illustrated the left flank of this alternative upper slope is rather flat. There are seen numerous inselbergs of massive exfoliated granite separated by sloughs of wind blown sand. The section suggests windblown sand deposits of 0 to 5 m thick. The feasibility investigation of this part of the dam will require trenching and seismic profiling to determine the depth of bedrock and possibility of buried river channels. Three boreholes are recommended; they should be drilled to depth of 15 m into unweathered rock. Some investigations will be needed west of the zone illustrated on Drawing D4.

Right Flank.

The right flank of this centre line is 500 m long. The lower part of the flank crosses a 100 m wide, elevated alluvial terrace. In the interpreted section (Drawing D4) the depth of alluvium in the elevated terrace is shown as 0 to 20 m deep, 15 m on average. The alluvium will comprise silt and very fine sand with localised layers and lens of abandoned channel clay deposits. The bedrock is likely to be metasediment, biotite schist, and amphibolite gneiss. The feasibility investigation of this part of the dam will require target drilling and seismic profiling as explained previously, one or two boreholes should be drilled to depth of 20 m into slightly or unweathered rock.

The upper part of the flank is a rock slope devoid of soil cover. The rock is slightly, to moderately weathered sheared pink or brick red syenite granitoid gneiss. The rock exposures are splintery due to the pronounced foliation. At depth of 2 to 5 m the rock mass is expected to be unweathered and of high quality. The feasibility investigation of this part of the dam will require one borehole should be drilled to depth of 10 m into slightly or unweathered rock, with Lugeon tests to determine the rock mass permeability. Trenches or pits should be excavated to investigate dykes and other structural features.

If saddle dams are required similar geological conditions will pertain.

Injection grouting.

The weak rocks inferred below the deep channel may require curtain grouting to prevent seepage under the embankment. The same applies to the foliated gneisses underlying the right flank. It is possible that the unweathered massive granite underlying the western half of the dam is impermeable.

Diversion.

The river diversion will be achieved through a +-500 m wide, diversion channel situated on the left side of the river section, taking advantage of the ephemeral channel system. The channel will be excavated down to bedrock.

Massive Granite Quarry.

Two possible quarry sites are indicated on Drawing D2. They are considered to be ideal quarry sites from a geological view point. They comprise prominent domes of massive granite. Mapping and sampling of the dome will be necessary at feasibility stage to confirm the reserves of the quarry, and the quality of the materials present.

Materials Investigations.

Some wide-ranging investigations are justified, of natural sand and pebble and clay deposits in the elevated alluvial terraces on the west side of the river.

Conclusion: Comparison of Centrelines

In many respects the upstream line seems better. It has steeper flanks and shallower alluvium. But these advantages can only be confirmed by feasibility investigations which include wide ranging drilling, pitting and seismic profiling. Also topographic survey over a wide area is essential to confirm the optimum FSL, and requirement for saddle dams.

The downstream option seems to have superior foundation rocks. Again this requires confirmation.

If the decision is made, for reasons of economy, to investigate only one centreline, then it is recommended to choose the upstream option.

5.13 SEISMICITY AND EARTHQUAKE PARAMETERS

The investigation by Acres, 1993, indicates that Dal Site falls on the stable intra-cratonic plate. An epicentre map from the US Geological Survey, National Earthquake Information Centre, for the time span 1850 to 1991, and reproduced by Acres, illustrates two epicentres at distances of 200 km north of the site 180 km south of the site respectively.

The northern epicentre is at Lake Nasser and is interpreted as induced by the reservoir. Its magnitude was 4 on the Richter scale. The southerly epicentre was at Dongola and also measured only 4 on the scale. These are isolated minor events therefore.

The nearest earthquake hot-spot to Dal, is the Red Sea rift trench, but this is 800 km from Dal. Clearly the Dal site lies in a zone of low to very low risk of seismic hazard.

5.14 REFERENCES

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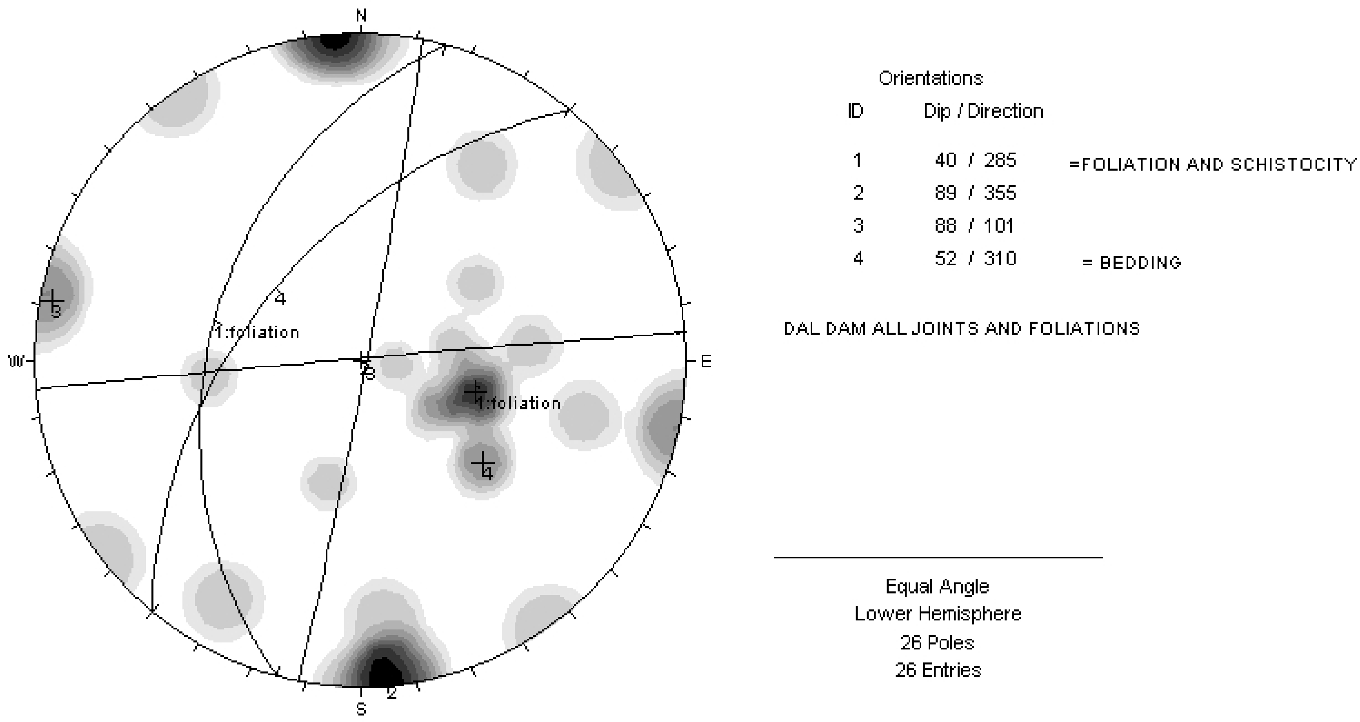
APPENDIX 5.1

Discontinuity Data and Stereographic Plots using “DIPS”


N
W
E
S
1:foliation
1:foliation
4
2
Orientations
ID Dip / Direction
1 40 / 285 =FOLIATION AND SCHISTOCITY
2 89 / 355
3 88 / 101
4 52 / 310 = BEDDING
DAL DAM ALL JOINTS AND FOLIATIONS
Equal Angle
Lower Hemisphere
26 Poles
26 Entries

dip	bearing
46	236
70	212
90	180
32	260
90	356
52	312
40	286
80	30
90	145
90	354
30	293
90	284
90	100
51	307
76	355
90	233
55	265
40	276
42	15
12	277
50	84
87	352
30	308
45	286
70	284
40	293

DAL FOLIATION & JOINT MEASUREMENTS

APPENDIX 5.2

Photo Album and Caption Document

Plate 1 : Rock slope of upper right flank of downstream centreline, and alluvial terrace. The slope crest in the middle background defines the centreline, between this crest and the skyline is a low defile which might necessitate a saddle dam.

Plate 2 : River section of downstream centreline, and alluvial terrace, and deep channel

Plate 3 : Across the river section of downstream centreline, visible in background, the left flank must curve along the line of granite domes, with possible saddle dams between each . The rocky crag in centre of river is the next island downstream from Diff island, upon which are the main ruins.

Plate 4 : Looking along left flank of the downstream centreline, nb elevated alluvial terrace with clay core [way point 66 photo 125]. Plate 5:

Plate 5 : Massive intruded granite on west side of river section of downstream centreline

Plate 6 : Clay with calcified root structure, crest of elevated alluvial terrace mid way up left flank of downstream centreline.

Plate 7 : Sheared granitoid gneiss on right flank of downstream centreline.

Plate 8 : Central island downstream centreline, sheared gneiss, rock type: PC2

Plate 9 : Meta-sediment and phylite, quartzite, outcrop at boat crossing, just upstream of bottom of right flank of upstream centreline. Rock type PC4

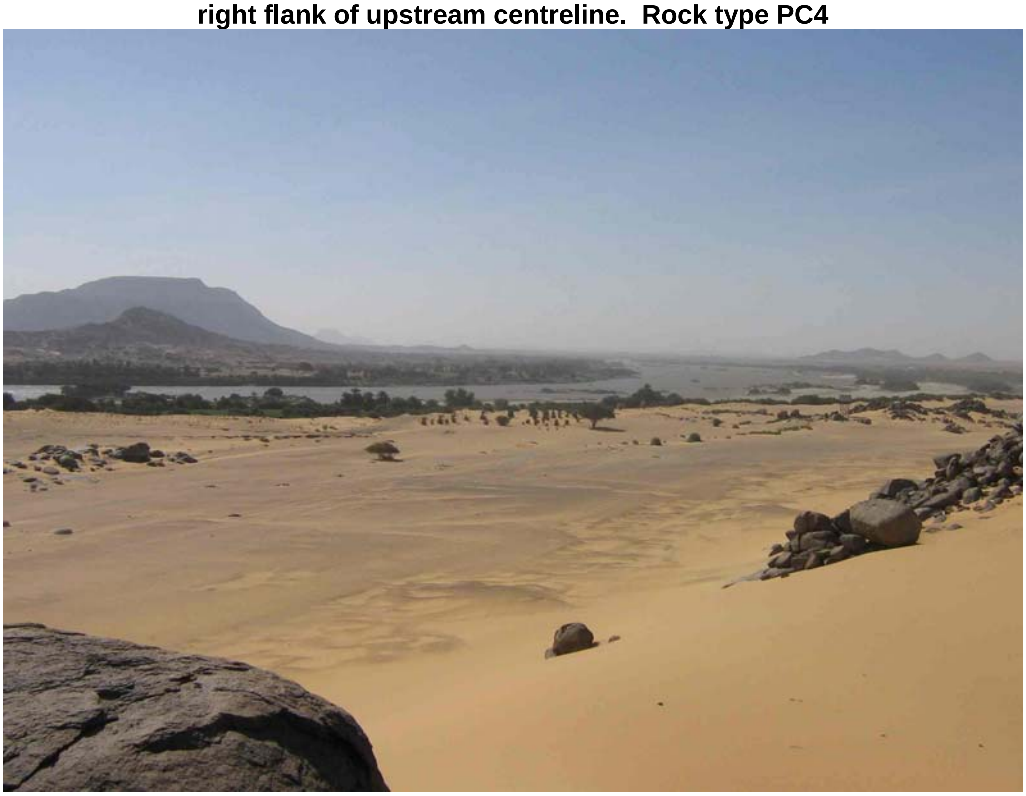


Plate 10 : From waypoint 45 , koppie near crest of left flank of upstream centreline, shows buried river channel as part of upper, old, alluvial terrace

Plate 11 : Across the river section of upstream centreline, visible in background, is the rock right

Plate 12 : Looking along right flank of the upstream centreline, nb granite pavements and sandy swales [way point 45 photo 98]. Plate 5: [way point 16, photo 25]

Plate 13 : Amphibolite gneiss with deformed quartz vein near right flank of upstream centreline. Rock type PC 3

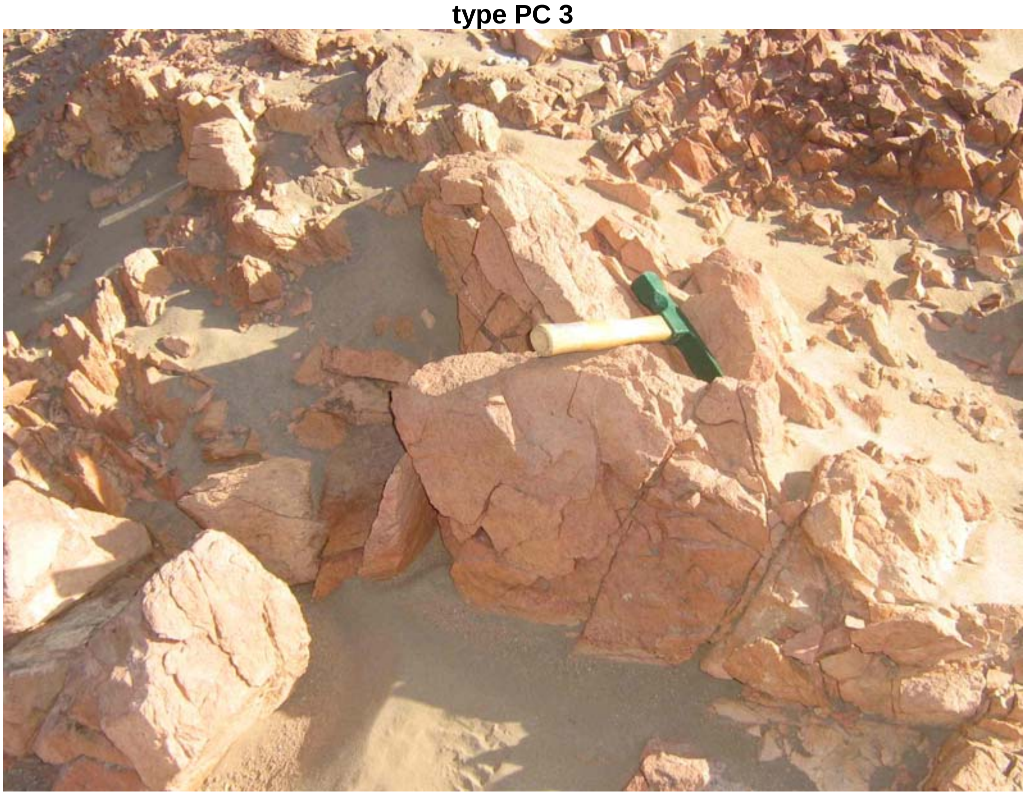


Plate 14 : Pink to brick red, medium grained syenite? Granitoid gneiss on right flank of upstream centreline. Rock type PC5

Plate 15 : Centreline of upstream option goes through the Assyrian Fort on central island that guards the Dal Cataract at its upper reach.

APPENDIX 5.3

Rock Mass Strength Properties after Prof. Tilib Nurallah

Rock Geomechanical character:

The ITC System of engineering geological mapping (Rengers and Soeters, 1981-2) was followed to show the potential of the rocks at the dam site as engineering materials. Further detail on jointing, other structural features and the mechanical character of rock masses were added.

Rock mass strength was determined by the rock material strength and the intensity of the rock. The irregular lump point-load test (Broch and Franklin, 1972) was used for strength classification of rock materials because it is sufficiently quick and cheap. It is particularly useful when classifying outcrop materials prior to exploratory drilling for a more detailed study. If jointing is irregular, the description of joint spacing is based on characteristic minimum and maximum sizes of the blocks into which the mass disintegrated. The values for the range of joint spacing and for the range of material strengths were plotted in a rock mass strength diagram.

Accordingly, units of medium, high and very high rock mass strength were identified. Because of the shearing effect to which the area has been subjected, all rock types (granite, granite gneiss and gneiss) would show heterogeneity, laterally and probably vertically in their rock mass strength. Generally, characteristic block size for medium rock mass strength unit is 20x30x40 cm to 30x50x60 cm and median value for point-load testing ranges from 40kgf/cm to 70 kgf/cm. For high rock mass strength unit, characteristic block size was found to be 60x70x90 cm to 70x80x90 cm and the median value for point-load testing ranges from 70kgf/cm to 90kgf/cm. Characteristic block size for units having very high rock mass strength is 70x90x100 cm to 90x140x180 cm and the median value for point-load testing ranges from 90 kgf/cm to 160 kgf/cm.

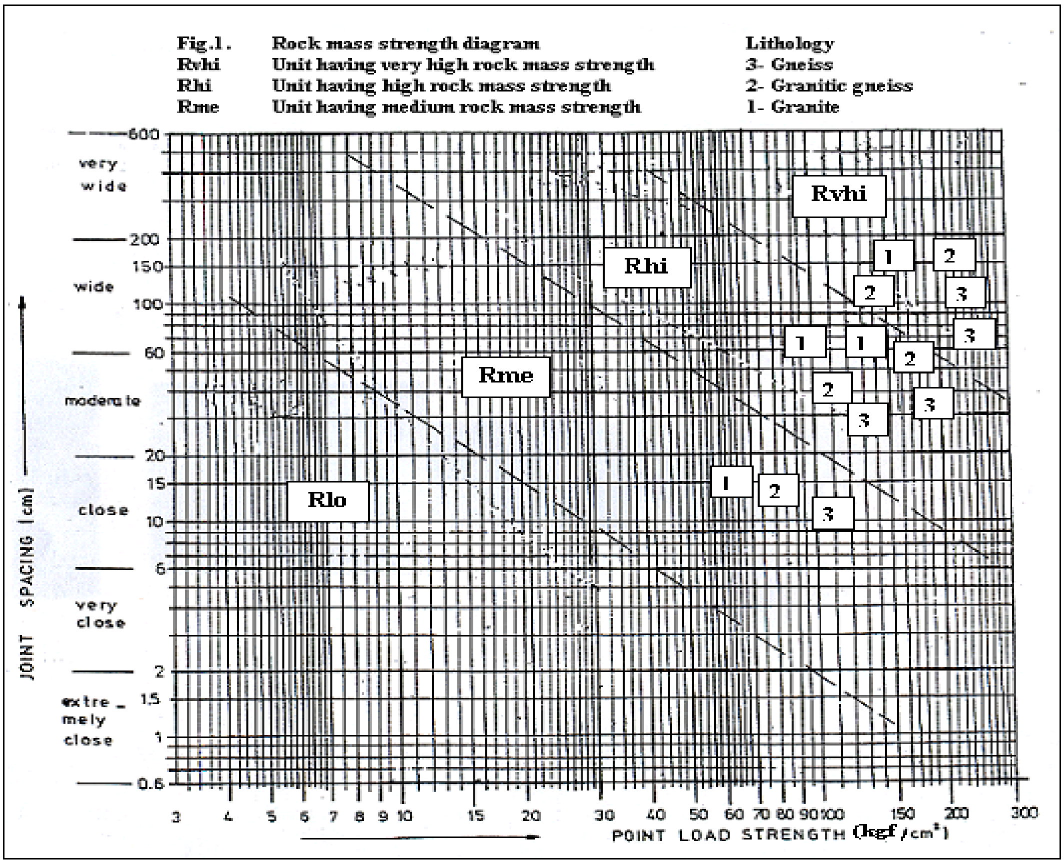


Fig.1. Rock mass strength diagram
Rvhi Unit having very high rock mass strength
Rhi Unit having high rock mass strength
Rme Unit having medium rock mass strength
Lithology
3- Gneiss
2- Granitic gneiss
1- Granite
Rvhi
Rhi
Rme
Rlo
very wide
wide
moderate
close
very close
extremely close
JOINT SPACING (cm)
600
200
150
100
60
20
15
10
6
2
1.5
1
0.6
3 4 5 6 7 8 9 10 15 20 30 40 50 60 70 80 90 100 150 200 300
POINT LOAD STRENGTH (kgf/cm²)

6. DESCRIPTION OF THE PROPOSED PROJECT

6.1 DAL PROJECT SITE

The Dal dam site is located some 200 km downstream of Dongola and at the upstream extremity of Lake Nubia/Nasser. At this point the topography on the East bank is steep locally but rises only very gently on the West bank. The valley profile at the site allows development of the dam, diversion works and power station as surface structures within the river channel.

The site is suitable for dams up to some 20 - 40 metres in height but appears to be limited by the elevation of the left bank where an extensive embankment may be required as well as saddle dams in the reservoir rim and by a low saddle on the East bank at an elevation of approximately El. 224 m.

The general arrangement of the propose project is presented on Drawing D5.

6.2 RESERVOIR

The reservoir elevation-area-capacity relationships were derived from surveyed cross-sections of the valley carried out at 5 km intervals as part of previous studies and are presented in Table 2.5 and Figures 2.1 and 2.2. The proposed reservoir full supply level of El. 201 m has been selected following appraisal of the site during the inception mission and later geological studies and taking account of initial estimates of affected population.

6.3 DAM

6.3.1 Dam Alignment

The selected dam alignment lies at the upstream end of the Dal cataract. At the site bedrock is exposed both in the river channel and at higher elevations on the abutments (as described in more detail in Section 5). Wind blown sand deposits are found between the rock outcrops. Various alternative alignments would also be possible but would appear to be likely to require an increased dam volume and associated higher costs. The Dal dam at the selected site will have a crest length of some 4,000 m and will have a maximum height of some 30 metres.

6.3.2 Dam Type

Since the 1970's concrete faced rockfill (CFR) has been widely adopted for medium and large embankment dams especially in areas of high seismic risk or where suitable materials for earthfill dams, such as impervious clay core material, are not available within a reasonable distance.

Having regard to the site topography, geology and availability of materials at the Dal site, together with the substantial flows which must be accommodated both during construction and in the spillway facilities it is considered that an CFR dam is the most appropriate choice of dam type and offers advantages over alternative dam types such as clay-core rockfill or concrete dams. Typical dam details are presented on Drawing D6.

6.3.3 Sources of Materials for Dam Construction

The principal materials for CFR dam construction comprise rockfill together with coarse and fine aggregates for concrete structures and the dam face. Rockfill and aggregates are expected to be sourced from quarries to be developed in the immediate vicinity of the Dal dam site.

6.4 RIVER DIVERSION WORKS

The width of the valley at the river level allows development of a river diversion arrangement based passing flow through the western channel while construction of the spillway and power station structures is carried out within the Eastern channel protected by temporary cofferdams. The diversion works have been designed to have an ultimate capacity of 13,750 m^3/s. River diversion during construction will take place in a number of stages as follows:

Stage 1

Excavation to enhance capacity of western diversion channel and construction of cofferdams to protect works area in Eastern channel.

Stage 2

Construct power station substructure and spillway structures in Eastern channel works area. Construct rockfill embankment to form East abutment section of dam and install concrete facing.

Stage 3

Remove upstream and downstream cofferdams from Eastern channel. Open spillway gates to pass river flows downstream. Continue construction of power station and installation of generating plant.

Stage 4

Construction of cofferdams to protect works area in Western channel.

Stage 5

Construct rockfill embankment to form West abutment section of dam and install concrete facing.

Stage 6

Remove downstream cofferdam in Western channel. Control release of flow through spillway gates and commence impounding.

Stage 7

Complete impounding and commence generation.

The diversion stages are presented on Drawing D7.

6.5 SPILLWAY

The spillway will comprise 12 radial gates each 10 m wide by 12.5 m high, with a total discharge capacity of 20,000 m^3/s with the reservoir at full supply level. The spillway gates have been sized to be capable of discharging the 1 in 10,000 year flood released from the Merowe dam upstream.

Each of the spillway gate bays will be equipped with stoplog guides. It is envisaged that two sets of stoplogs will be provided to allow two gates or one chute to be isolated at any one time for maintenance to the radial gates, seals and the spillway structure.

Typical details for the spillway are presented on Drawing D8.

6.6 POWER WATERWAYS

The power waterway system will comprise a reinforced concrete intake structure incorporating unitised intake gates and associated control equipment for each of the eight turbine-generator units. The intake structure will also be equipped with trash screens and trash raking mechanism, and slots to allow bulkhead gates to be deployed for gate, waterway and unit maintenance. The intakes will be integral with the concrete semi-spiral arrangement of the Kaplan turbine units.

Typical cross sections through the power waterways and powerhouse are presented on Drawing D9.

6.7 POWERHOUSE STRUCTURE AND TAILRACE

The powerhouse will be a surface type structure of reinforced concrete and structural steel, construction, integral with the dam structure and located in the Eastern river channel. The powerhouse accommodates a loading/service bay, one bay for each of the 8 Kaplan turbine units, control block and offices. Three phase transformer bays (1 per turbine unit) will be located to the downstream side of the powerhouse on a terrace at elevation 190 m. The tailrace of the Dal scheme will discharge directly into the existing river channel.

Principal approximate dimensions and elevations are given in Table 6.1 with typical details being presented in Drawings D9 and D10.

Table 6.1 : Dal Powerhouse Principal Dimensions and Elevations

Description	Dimension/Elevation (m)
Overall Length (m)	211
Machine Hall Width (m)	20
Foundation Width	61
Overall Height	61
Unit Centre Line Spacing	21
Crane Beam Elevation	203.0
Loading/Service Bay Elevation	190.0
Machine Operating Floor Elevation	185.0
Generator Floor Elevation	180.0
Turbine Floor Elevation	176.0
Turbine Setting Elevation	170.5
Draft Tube Invert Elevation	160.0

6.8 SWITCHYARD

The switchyard will be located on the right bank, downstream of the dam site, at a horizontal distance of approximately 500 m from the powerhouse. The switchyard will be constructed on a terrace at elevation 190 m with approximate dimensions of 300 m by 200 m.

6.9 POWERHOUSE MECHANICAL AND ELECTRICAL PLANT

6.9.1 Turbines and Governors

The turbines will be vertical shaft Kaplan type with concrete semi-spiral casing. Each turbine will be directly connected to a vertical shaft synchronous generator. The water for each turbine will be supplied through a separate intake structure. Intake gates will be provided for emergency shutdown of the units. At the outlet, draft tubes stoplogs will also be provided to permit dewatering of the turbine for inspection and maintenance purposes.

The rated output of each turbine will be 50 MW assuming a design net head of 18 m. The synchronous speed of the unit has been selected at 100 rpm. Each turbine will be equipped with an electronic digital type governor.

6.9.2 Draft Tube Stoplogs and Hoist

The following equipment will be installed:

- 4 sets of draft tube single-leaf sliding stoplogs and
- one open air travelling gantry crane at El. 190 m. (rated capacity = 30 t).

6.9.3 Powerhouse Travelling Overhead Crane

Main equipment will be handled by two overhead travelling cranes operating in tandem, having a total capacity of 200 t and a span of approximately 20 m.

6.9.4 Generators

The generators will be of conventional air cooled, self-ventilating type, with a rated capacity of approximately 62 MVA. Voltage will be in the range 9 - 11 kV (to be confirmed during detailed studies undertaken at Feasibility Stage). The speed of each generator is 100 rpm which corresponds to a 30 pole pairs generator.

The generators will be connected to three phase transformers by metal-enclosed, isolated phase bus ducts. A coupling circuit breaker SF6 type (rated voltage 24 kV) is provided to connect the generator to the grid through the generator transformers.

6.9.5 Main Transformers

The 8 three phase transformers will be placed on a terrace at elevation 190 m, on the downstream side of the power station building in open-air separate concrete-enclosures.

Each main transformer will be a single phase, two winding, oil-immersed transformer, with oil forced, water-forced (OFWF) cooling system.

The connection between the transformers and the Dal switchyard, located approximately 500 m downstream of the powers station, will be by means of overhead lines. HV circuit breakers SF6 type will be provided at the Dal switchyard.

6.9.6 Control and Protection System

Operation will be carried out through a Computerised Supervision Control and Data Acquisition System (SCADA).

6.9.7 Mechanical and Electrical Auxiliary Equipment

The powerhouse will be equipped with all necessary mechanical auxiliary equipment as listed hereafter:

- cooling water system,
- compressed air system,
- oil supply, handling, purification and storage system,
- unit dewatering and powerhouse drainage system,
- fire protection system,
- heating, cooling and air ventilation system,

- domestic water system, and

The powerhouse will be equipped with electrical auxiliary equipment as listed hereafter:

- AC station services auxiliaries,
- emergency diesel generators (powerhouse, water intake and dam),
- DC station service,
- un-interruptible power supply (UPS),
- earthing system,
- cables, cable trays and conduits,
- lighting and receptacle systems,
- luminaries supplied for areas,
- fire alarm system,
- communication system, and
- master clock system.

6.10 ACCESS ROADS AND BRIDGES

Reliable access to the project site will be required to be available for efficient and timely construction and subsequent operation and maintenance of the Dal hydropower project.

The access arrangements will need to be capable of carrying all envisaged construction traffic including transport of construction plant, materials and equipment to the site, together with normal construction traffic around the site. In particular, the roads and bridges will need to be capable of carrying the heavy loads associated with the main items of the permanent mechanical and electrical equipment for incorporation in the project, specifically the turbine components, generator components and transformers.

Construction plant, materials and the major items of permanent equipment for the project will be transported to the site over the existing national road network to Dongola where a major river crossing is under construction. Beyond Dongola existing roads and tracks extending towards the project location will require upgrading.

A temporary crossing of the Nile will be required during construction. This may be by bridge or ferry. It is envisaged that the dam itself would be used as a future road crossing following completion of the project.

6.11 NAVIGATION

It would be possible to incorporate a navigation lock within the overall Dal development to facilitate river transport along the Nile from Lake Nubia/Nasser to Dongola. Detailed hydraulic model studies would be required to determine the optimum location of the lock to minimise operational difficulties. However, before committing to this it is recommended that detailed studies are carried out of the navigability of the upper reaches of Lake Nubia/Nasser as the progressive deposition of sediment in this area may present difficulties for navigation.

6.12 FISH PASSAGE

The environmental studies have concluded that there are no known migratory fish species in the Dal reach of the Nile. Accordingly, there would not appear to be any need for or justification of the expense of including a fish pass within the project design. However, a "Borland" type fish pass could be accommodated adjacent to the power station structure if required. Detailed consideration would be needed of the siting of the fish pass for successful operation since it is important to create conditions which are attractive to fish to encourage them to enter the pass.

6.13 CONSTRUCTION INFRASTRUCTURE

Construction of the Dal project will require the following infrastructure:

- Construction camp.
- Construction works areas (e.g. crusher, concrete batching plant, etc.).
- Quarry locations.
- Site access roads (not included those dependent on the contractor's methodology).

Drawing D11 presents the overall project layout and provides approximate locations for the above components.

7. COST ESTIMATION

7.1 INTRODUCTION

This section describes the methodology adopted for preparation of cost estimates for the Dal hydropower project and presents details of the estimated costs of the selected project.

The cost estimate has been broken down into 7 main sections as follows:

1. Environmental mitigation measures
2. Access roads and site facilities
3. Reservoir costs
4. Civil works
5. Electro-mechanical equipment
6. Engineering and supervision
7. Owners administration

The cost estimates given in this Report are based on unit and lumpsum prices applied to the quantities of major work items calculated for various components of the Project. These cost estimates provide an estimate based upon the price level of 2005 thereby providing a direct comparison with the Pre-Feasibility Study of the Karodobi Multipurpose Project and take account of differing cost levels in Sudan compared to Ethiopia.

No taxes and import duties are included in the cost estimate.

The summary of cost estimates has been used for economic and financial analysis.

The currency used in the cost estimates is the US Dollar and the following rate of exchange has been adopted:

US$ 1.00 (US Dollar) = Sudan Dinar SD 200

7.2 CIVIL WORKS

The cost estimates for the civil works have been established from the following principles:

- Based on the methods of construction and programme for the major cost items.
- Unit rates based on the Consultant's in-house data base from other projects in the region, experience curves and present market prices.

- Measuring the principal construction items and extending those items by the unit rates and adopted prices.
- Making allowances for establishment items such as mobilisation and demobilisation of construction plant, contractor's site installation, etc.
- Making appropriate allowances for unmeasured items.
- Applying appropriate allowances for contingencies, to both estimating and construction aspects of the work.

Some items which have no specific details at pre-feasibility stage have been treated as lump sums based on previous experience of other projects.

A list of the main unit rates adopted for costing of the project is given in Table 7.1 below.

Table 7.1 : Unit Rates

Description	Unit	USD/Unit
Clearing Light Vegetation	Ha	550
Clearing and grubbing	Ha	5500
Soft excavation (unconfined)	m^3	5
Soft excavation (confined/difficult)	m^3	7
Rock excavation (unconfined)	m^3	14
Rock excavation (confined, difficult)	m^3	20
Backfill and compact	m^3	6
Cofferdam fill	m^3	10
Embankment Fill	m^3	24
Foundation preparation for concreting	m^2	7
Formwork	m^2	65
Mass concrete	m^3	127
C35 Structural concrete	m^3	143
C45 Structural concrete	m^3	154
Reinforcement steel	t	1760
Drilling and grouting	m	165
Structural Steelwork	t	6530
Crushed rock surfacing	m^2	5

The different unit rates used in compiling the cost estimate include all direct costs including purchase costs of construction plant and the operation and maintenance cost and the relevant portions of site installations.

It has been assumed that most of the heavy construction plant and the heavy concrete batching, mixing and transportation plant will have to be brought into the country.

The contractor's preliminaries and general costs amounting to about 25% of direct cost for the dam and the power plant work have been included in the unit rates. The contractor's preliminaries and general costs includes the contractor's mobilisation, operation of yard and offices, insurances and bonds, international transports and air freight, site administration, travel cost for expatriates, profit and parts of the site installations not included in the direct costs for the various items.

For all major structures (e.g. dam, spillway, diversion works, low level outlets, powerhouse and tailrace) preliminary designs were developed and drawings to appropriate scales have been prepared. Materials and quantities required have been computed using the engineering design drawings consisting of plans and sections of the major components of the project. Cross sections surveyed at the Dal dam site by GPS techniques have been used as the basis for calculation of quantities in the absence of detailed topographic maps.

The civil construction works are broadly defined as follow:

Infrastructure Requirements

These works are described in Section 6 and cover aspects such as:

- Access Roads.
- Temporary bridge over the Nile River at the dam site.
- Minor bridge crossings.
- Housing, comprising low and high-density accommodation, community buildings, amenities areas and places of worship.
- Electricity supply, sewerage and water reticulation.
- Road improvements.
- Road maintenance.

Site Establishment

This covers major cost expenditures, which would normally be included in a contractor's tender, to enable the contractor to establish himself on site. For the Dal project they are deemed to comprise:

- Site access roads (not accounted for in the Infrastructure Requirements).
- Establishment of principal works areas and fill platforms, e.g. materials storage, concrete batching and aggregate crushing plant platforms at the powerhouse and substation areas.
- Other contractor's site installations, e.g. offices, workshops, saw yard, reinforcement bending yard, canteen, etc.
- Mobilisation and demobilisation of contractor's plant.

Diversion and River Closure Works

The stages of diversion and river closure are described in Section 6 and comprise the following works:

- Construction of temporary upstream and downstream cofferdams.
- Placing of rockfill and earthfill, some underwater.
- Removal of cofferdams, involving excavation of rockfill, some underwater.

Dam and Spillway

The civil works for the dam and spillway will comprise:

- Excavations in soft and rock material.
- Foundation preparation for the dam.
- Rockfill and filter zones for the dam body
- Concrete upstream facing for dam.
- Structural concrete works to the spillway, piers, chute and bridge.
- Pressure grouting works to dam curtain.
- Dam instrumentation and instrumentation houses.
- Drilling of drainage relief holes.
- High capacity pre-stressed anchorages to the radial gate trunnions.

Surface Powerstaion

The civil works associated with the power station comprise the following:

- Excavation in soft and rock material.

- Structural concrete works forming the intake, powerhouse sub and superstructure, and concrete placed in stages to suit the phased erection of the turbine draft tube linings and spiral casings, and the generator.

- Building finishes.

Switchyard Civil Works

The switchyard civil works will entail site clearing, excavations and concrete works for switchgear foundations and cable trenches, drainage measures, gravel surfacing around equipment bases and the construction of security fencing and gates.

External Works

These works will involve landscaping, planting of trees and shrubs, grassing, laying of kerbings, miscellaneous drainage and the like to the powerhouse and intake structure environs.

7.3 ELECTRICAL & MECHANICAL EQUIPMENT COSTS

7.3.1 General Assumptions

The process used for arriving at the estimated costs for the equipment and installations includes an analysis of the costs of the various plant components derived from the Consultant’s database and adapting them to the characteristics of the Border project.

Cost estimates for the M & E equipment are based largely on budgetary prices from reputed manufactures, both local and foreign.

The cost estimates include ready-for-service installations appropriate for this pre-feasibility design stage. The cost estimates include an allocation for spare parts.

A contingency allowance of 5% has been added to the direct costs for hydraulic steel structures and mechanical and electrical works resulting from the unallocated risks inherent in the scheme layout at this pre-feasibility stage.

Most of the equipment has to be imported. The local component essentially comprises the costs for minor ancillary equipment, local erection staff and on-shore transportation.

The prices include for the suppliers’ on-costs and margins. Indirect costs, e.g. site establishment for offices and workshops, housing for employees, etc. are included in the spread of costs.

7.3.2 Hydraulic Steel Structures

Costs of gates, trash racks, stoplogs, and associated embedded parts, steel linings of waterways etc. have been built up from calculated weights of the equipment and current costs of manufacturing from recent quotations for similar equipment. Special allowances for sea and overland transport as well as costs for erection, testing and commissioning have been included.

The scope of supply for the hydraulic steel structures will be as follows:

Spillway:

- Radial gates
- Stoplogs and gantry crane

Intake structure:

- Trash screens and trash raking machine
- Vertical gates
- Stoplogs and gantry crane

Powerhouse draft tube stoplogs and crane

7.3.3 Mechanical Powerhouse Equipment

A computer model has been used to generate the speed, setting, turbine dimensions, weights and costs of the 8 vertical axis Kaplan turbines and auxiliary equipment with input of discharge capacities and heads appropriate to the scheme.

The cost estimates for the mechanical powerhouse equipment include delivery, erection and commissioning. The scope of the mechanical powerhouse equipment covers the following items:

- Turbines and governors
- Unit cooling water systems
- Draft tube steel linings
- Powerhouse cranes
- Dewatering and drainage systems
- Compressed air systems
- Mechanical auxiliaries:
- Sanitary water system
- Fire protection system
- Oil handling and treatment system
- Air conditioning and ventilation

7.3.4 Electrical Powerhouse Equipment

The costs for the electrical equipment comprise ready-for-service installations. The electrical equipment is assumed to be largely manufactured offshore and has to be imported. The scope of the electrical powerhouse equipment covers the following items:

- Synchronous generators and ancillaries
- Voltage regulator and excitation system
- MV circuit breakers
- MV bus bars
- Power transformers 13/400kV, single phase
- HV circuit breakers
- Control and protection systems including SCADA, unit protection and unit measurement

Electrical auxiliaries:

- MV and LV distribution
- DC UPS distribution
- Earthing network
- Cables and cable racks
- Fire detection system
- Flood detection system
- Lighting and small power
- Service transformers
- Diesel back-up units

7.4 TRANSMISSION SYSTEM

The transmission system improvements necessary to evacuate power from Dal to Dongola and elsewhere in the Eastern Nile region have been identified as part of the generation expansion planning under in Module 6 of this study. Accordingly the cost estimates and time sequence of construction for the various transmission line developments are reported separately.

7.5 ENVIRONMENTAL MITIGATION COSTS

The environmental costs in Table 7.2 provide for the compensation and mitigation of direct impacts not managed under the main design concept.

The guiding principle is that people or communities directly affected by the construction of the Dal scheme should be no worse off (and preferably better off) after project implementation. What must be avoided is a situation whereby people in the direct impact zone “subsidise” the project through a reduction in their standard of living or income generation opportunities.

7.6 ENGINEERING ADMINISTRATION AND PHYSICAL CONTINGENCIES

To arrive at the total cost for the project, the costs of engineering, supervision, administration and contingencies have to be added to the construction costs.

Feasibility Study, Final design, preparation of bid documents, bid evaluation and participation in contract negotiations, preparation of work drawings and supervision of construction have been taken as 10% of the total construction cost.

The owner’s administration costs have been taken as 4% of the total construction and environmental costs.

To cover unforeseen costs, contingencies have been added to the construction costs with 5% for electrical and mechanical work, 10% for environmental mitigations and infrastructure works and 15% for civil works.

7.7 TOTAL PROJECT CAPITAL COST

A summary of the costs for the Dal Hydropower Project is given in Table 7.2. Detailed costs are presented in Table 7.3.

Table 7.2 : Summary of Costs

Item	Total Cost (MUSD)
ENVIRONMENTAL MITIGATIONS	
Environmental Mitigations	200.0
Contingencies(10%)	**20.0**
TOTAL ENVIRONMENTAL MITIGATION	**220.0**
INFRASTRUCTURE	
Access Roads & Bridges	32.8
Operators village & infrastructure	11.3
Sub-Total	**44.1**
Contingencies(10%)	**4.4**
TOTAL INFRASTRUCTURE	**48.5**
RESERVOIR	**0.0**
Clearance	16.5
TOTAL RESERVOIR	**16.5**
CIVIL WORKS	
Diversion Works	17.2
Embankment Dam	98.6
Spillway	53.6
Powerhouse, Gravity Dam & Tailrace	125.9
Workshop and Stores Building	0.4
Switchyard & Plant Buildings	5.3
Sub-Total	**300.9**
Contingencies(15%)	**45.1**
TOTAL CIVIL WORKS COST	**346.0**
MECHANICAL, ELECTRICAL & HYDROMECHANICAL WORKS	
Generating plant	207.0
Hydromechanical Equipment	87.0
Switchgear	35.0
Subtotal	**329.0**
Contingencies (5%)	**16.5**
TOTAL M & E and HYDROMECHANICAL	**345.5**
Engineering, admin. & construction management (10%)	**97.6**
Owners Administration (4%)	**39.1**
TOTAL PROJECT COST (MUSD)	**1,113.2**

Table 7.3 : Dal Hydropower Project - Detailed Cost Estimate (Sheet 1 of 2)

Item	Qantity	Unit	Rate ($)	Cost ($)	Totals ($)
ENVIRONMENTAL MITIGATIONS					
Environmental Mitigations	1	Sum	**200000000**	200,000,000	
TOTAL					**200,000,000**
Contingencies(10%)					**20,000,000**
TOTAL ENVIRONMENTAL MITIGATION					**220,000,000**
Roads & Infrastructure					
New roads in mountainous terrain	10	km	583,000	5,830,000	
Construction access roads	10	km	220,000	2,200,000	
Upgrading to existing tracks	120	km	165,000	19,800,000	
Temporary bridge/ferry crossing	1	Sum	5,000,000	5,000,000	
Operators village & infrastructure	1.0	Sum	11,275,000	11,275,000	
TOTAL					**44,105,000**
Contingencies(10%)					**4,410,500**
TOTAL INFRASTRUCTURE					**48,515,500**
Reservoir					
Clearance	30,000	Ha	550	16,500,000	
TOTAL RESERVOIR					**16,500,000**
CIVIL WORKS					
Diversion Works					
Clearing and grubbing	8	Ha	5500	44,000	
Soft excavation (unconfined)	1,100,000	m^3	5	5,500,000	
Rock excavation (unconfined)	450,000	m^3	14	6,300,000	
Cofferdam Fill	425,700	m^3	10	4,257,000	
Cofferdam Removal	55,950	m^3	5	279,750	
Unmeasured Items (5%)				819,038	
Subtotal					**17,199,788**
Embankment Dam					
Clearing and grubbing	17	Ha	5500	93,500	
Soft excavation (unconfined)	798,100	m^3	5	3,990,500	
Rock excavation (unconfined)	398,850	m^3	14	5,583,900	
Excavate to stockpile, haul & compact	2,284,600	m^3	25	57,115,000	
Reinforced concrete	56,950	m^3	143.00	8,143,850	
Formwork	134,450	m^2	65.0	8,739,250	
Reinforcement	3,370	t	1760.00	5,931,200	
Unmeasured Items (10%)				8,959,720	
					98,556,920
Gated Spillway					
Clearing and grubbing	8.0	Ha	5500	44,000	
Soft excavation (unconfined)	181,200	m^3	5.0	906,000	
Rock excavation (unconfined)	115,000	m^3	14.0	1,610,000	
Foundation preparation	11,300	m^2	7.0	79,100	
Drilling and grouting	3,400	m	165.0	561,000	
Formwork	134,700	m^2	65.0	8,755,500	
Reinforced concrete	149,700	m^3	143.00	21,407,100	
Reinforcement	10,030	t	1760.00	17,652,800	
Unmeasured Items (5%)				2,550,775	
Subtotal					**53,566,275**
Powerhouse, Gravity Dam & Tailrace					
Clearing and grubbing	15.5	Ha	5500	85,250	
Soft excavation (unconfined) [Tailrace]	223,000	m^3	5.0	1,115,000	
Soft excavation (confined/difficult)	66,605	m^3	7.0	466,235	
Rock excavation (unconfined) [Tailrace]	412,500	m^3	14.0	5,775,000	
Rock excavation (confined/difficult)	242,598	m^3	20.0	4,851,960	
Compacted Fill	93,500	m^3	6.0	561,000	
Foundation preparation	14,000	m^2	7.0	98,000	
Drilling and grouting	4,200	m	165.0	693,000	
Formwork	156,300	m^2	65.0	10,159,500	
Reinforced concrete	274,500	m^3	143.00	39,253,500	
Reinforcement	23,470	t	1760.00	41,307,200	
Structural steel	105	t	5938.00	623,490	
Unmeasured Items (20%)				20,873,129	
Subtotal					**125,862,264**

Table 7.3 : Dal Hydropower Project - Detailed Cost Estimate (Sheet 2 of 2)

Item	Qantity	Unit	Rate ($)	Cost ($)	Totals ($)
Workshop and Stores Building					
Common excavation	250	m^3	5.0	1,250	
Compacted Fill	1,000	m^3	6.0	6,000	
Reinforced Concrete	450	m^3	143.00	64,350	
Formwork	300	m^2	65.0	19,500	
Reinforcement	27	t	1760.00	47,520	
Structural steel	25	t	6532.00	163,300	
Unmeasured Items (40%)				120,768	
Subtotal					**422,688**
Switchyard & Plant Buildings					
Clearing and grubbing	10.0	Ha	5500	55,000	
Soft excavation (unconfined)	18,000	m^3	5.0	90,000	
Rock excavation (unconfined)	162,000	m^3	14.0	2,268,000	
Compacted Fill	120,000	m^3	6.0	720,000	
Reinforced Concrete	2,800	m^3	143.00	400,400	
Formwork	7,950	m^2	65.0	516,750	
Reinforcement	224	t	1760.00	394,240	
Structural steel	40	t	6532.00	261,280	
Crushed rock surfacing	60,000	m^2	5.00	300,000	
Unmeasured Items (5%)				247,534	
Subtotal					**5,253,204**
TOTAL					**300,861,138**
Contingencies(15%)					**45,129,171**
TOTAL CIVIL WORKS COST					**345,990,309**
MECHANICAL, ELECTRICAL & HYDROMECHANICAL WORKS					
Generating plant	1	sum	207,000,000	207,000,000	
Hydromechanical Equipment	1	sum	87,000,000	87,000,000	
Switchgear	1	sum	35,000,000	35,000,000	
Subtotal					**329,000,000**
Contingencies (5%)					**16,450,000**
TOTAL M & E and HYDROMECHANICAL					**345,450,000**
TOTAL					**976,455,809**
Engineering, admin. & construction management (10%)					**97,645,581**
Owners Administration (4%)					**39,058,232**
TOTAL PROJECT COST ($)					**1,113,159,622**

8. CONSTRUCTION PLANNING

8.1 INTRODUCTION

This section presents a commentary on the construction planning aspects for the selected development at Dal. The proposed implementation programme for the project is shown in Drawing D12. The construction period indicated is derived from the quantities and typical construction plant outputs of the main civil works activities, combined with the manufacturing, shipping, erection and commissioning time scales required for the mechanical, electrical and transmission system equipment.

It can be seen that a total construction period of 5 years and 8 months is anticipated, commencing in mid 2011 with the award of the preparatory works contract to establish access roads and bridges, construction camp housing and facilities; followed a year later by the commencement of the main works contract, with completion by mid 2017. It should be noted that by adopting a staggered commissioning process as shown in Drawing D12, limited generation will commence approximately 7 months earlier in the last quarter of 2016.

The construction planning aspects of the project is described below.

8.2 PREPARATORY WORKS

Infrastructure Requirements

It is essential that access to the project site is available to construction traffic at the programmed commencement of the main works, therefore necessary upgrading of existing roads to the project site, new local access roads to works areas, a temporary river crossing and operator housing and infrastructure, will be undertaken and completed in advance of the main works under a separate preparatory works contract.

<u>Access Roads</u>

The access road works principally entail the following:

- Upgrade some 120 km of the 250 km of existing gravel/earth road and track between Dongola and the junction with the new access road to the project site to carry construction traffic.
- Construct some 10 km of new permanent access road to the project site and permanent housing areas.
- Construct some 10 km of construction access roads to main construction works areas and quarries.

<u>Temporary River Crossing</u>

The access road will arrive at the project site on the right bank of the Nile. A temporary river crossing will be required to access the diversion works, the quarries and embankment dam work areas on the left bank. The crossing may be by multi-span steel bridge suitable for construction in the shortest possible time, or by ferry. On completion of the project, the road along the dam crest, spillway and powerhouse will provide a permanent crossing.

Housing

The housing areas, together with associated water supply, sewerage and electrical reticulation works are also scheduled to start in advance of the main contract so that accommodation is made available to the construction workers and their families as soon after main contract mobilisation as practicable. The houses are to be constructed using blockwork and will have high quality finishes, on the assumption that they will be integrated into an operator's village in the future. It has been assumed that housing facilities would be constructed by local companies (it is anticipated that there would be several packages within the preparatory works contract). The required construction period for timely release of housing would be of the order of 7 months.

It is estimated that all access roads, including connecting roads to the contractor's works areas, offices, housing area, quarries and temporary Nile crossing will be completed within an approximate time frame of 14 months between mid 2011 and the last quarter of 2012.

8.3 MAIN WORKS

Site Establishment

Site Access Roads and Works Platforms

The main works contractor will extend the network of access roads constructed under the preliminary works contract to suit his construction methodology. From the outset it will be important to establish access to cofferdam fill borrow areas, and access to the upstream and downstream diversion cofferdam launch points on the right bank.

On the left bank, access roads will be established to the impervious core borrow area sites, transition material sources and rockfill quarries for the dam.

Works areas will be established on both sides of the river on levelled platforms established above flood level. The left bank will be accessed via a temporary river crossing established under the preliminary work contract. The right bank works areas, accessible from the main access road without river crossing, will accommodate handling and storage facilities for the majority of road delivered materials, concrete batching and cement/PFA storage facilities, a bar bending yard and saw yard. The main site offices will be established there. Being situated closest to the powerhouse and spillway, the right bank works areas will accommodate the stores and workshop facilities necessary for concreting plant, for the fabrication and assembly of the spillway and powerhouse gates, stoplogs and screens, and for reception and assembly of the main and auxiliary hydro mechanical and electromechanical plant.

The left bank works area, being on the same side of the river as the quarry sites, and situated closest to the dam works areas, will accommodate the crushing and screening plant, stockpiles of embankment rockfill and concreting aggregates, and stockpiles of conditioned impervious core material for the earthfill / rockfill dam. The left bank works area will also accommodate workshops for maintenance of the plant involved in constructing the earth / rockfill embankment dam and the concrete faced rockfill dam.

Tower cranes for formwork and concrete handling will be located over the spillway and powerhouse following Phase 1 diversion.

Materials Sources

Aggregate quarrying and processing is a critical activity scheduled to start in the last quarter of 2012 immediately after mobilisation of the main contract. Proving of aggregates for concrete and concrete mix trials must be completed before powerhouse and spillway concreting is due to commence in mid 2013. Quarries for high quality aggregates for concrete could be set up on the left bank as indicated on Drawing D2 to exploit sources of massive granite. Abundant sources of granitic gneiss suitable for embankment fill are widely available elsewhere. Impervious fill and transition material suitable for the core of the left flank dam appear to be available in adequate quantities on the left bank. More details are given in Section 5.11.

Concrete

Concrete batching facilities will be located on the right bank works area. Average concrete requirement is some 1000 m^3 per day. The concrete batching plant will be rated at 200 m^3 per hour. The planting is based on a duty plus standby basis where the duty plant will cover the average hourly placing requirement and the standby plant will supplement the duty plant during peak placing or breakdown. The plant will be equipped with substantial storage for cementitious materials. A stock of 20 to 30 days supply on site would be reasonable. Delivery of concrete from the batching plant will largely be by truck mixer to concrete pumps with some skipped concrete handled by tower cranes.

The massive nature of the concrete structure, combined with the hot climate, will necessitate precautions to limit maximum concrete placing temperatures to acceptable values. Precautions such as pre-cooling of aggregates, addition of flaked ice to the mixer, night-time concreting etc. will be required.

River Closure Works

The well-managed execution of the permanent river closure works will be one of the key features for ensuring timely completion of the project. Permanent river closure will be achieved in the following stages:

1) During dry the season, Remove obvious obstructions from the left side of the river that will become the diversion channel, and deepen where necessary. From the right bank, launch temporary cofferdams across the right half of the

river to the central island. Use the cofferdams to access the central island from the right bank and further deepen natural waterways in the diversion channel as necessary.

2) The right side of the river between cofferdams and the central island will be dewatered and maintained dry by pumping. Work will commence on excavation, foundation preparation and concreting of the powerhouse, the spillway and the concrete gravity dam structures that occupy the right side of the river channel. At the same time, continue to raise the right-side cofferdams to a level to provide security against wet season river floods.

3) While excavation, foundation and concreting works are underway in the right half of the river channel, commence construction of the earthfill / rockfill embankment dam on the left flank; excavate, prepare foundations and place rockfill and impervious fill from the left end extent of the dam to a concrete gravity transition structure by the left bank of the river.

4) Complete the concrete structures in the right half of the river channel to a stage that the river flow can be diverted through the spillway and the powerhouse is watertight. For the spillway structure all stoplog gate slots must be tested with stoplogs because access to the embedded tracks and sealing surfaces may not be possible after diversion. All radial gate guide and sealing surfaces must be in place. For the powerhouse structure the turbine and generator plant will not be installed at that time so watertightness will be achieved by placing intake and draft tube stoplogs in all 8 unit bays. All the intake screens, intake stoplog, intake guard gate and draft tube gate slots must be tested and the gates confirmed to be fully functional because access to the embedded tracks and sealing surfaces may not be possible after diversion.

5) After the 2015 wet season floods, remove the right-side downstream cofferdam, then the right-side upstream cofferdam including the islands that would impede flows towards the spillway, and allow the river to flow through fully open spillway bays.

6) From the left bank, launch cofferdams upstream and downstream of the dam works area towards the central island, upstream cofferdam first. This will complete diversion through the open spillway structure. The riverbed between the cofferdams and the central island will be dewatered and maintained dry by pumping. Work will commence on excavation, foundation preparation and concreting of the dam toe beam, and foundation preparation and placement of dam rockfill between the transition structure on the left bank and the spillway on the right. At the same time, the left side cofferdams will be raised to a level to provide security against wet season river floods.

7) While dam construction works are underway in the left half of the river channel, construction of the powerhouse will continue with the installation of the turbine and generator plant, placing embedding concrete and installation of auxiliary electromechanical plant.

8) Placement of the concrete facing will commence when the dam rockfill has been placed to full height and initial settlement has occurred. The facing will be complete and matured in time to impound the 2016 wet season flood.

9) Prior to the 2016 floods, the downstream left-side cofferdam will be removed. The upstream left-side cofferdam may remain in place to benefit flow characteristics towards the spillway. Impounding will be initiated by closing the spillway radial gates, compensation water will be released continuously from one or more radial gate bays for the duration of impounding.

10) On completion of impounding the turbine generator units will be commissioned in turn and generation will commence as soon as each unit becomes available.

The key activities pertaining to the construction schedule are described below.

Diversion Works and River Closure Earthfill Cofferdams

Provision of access to the diversion channel on the left side of the river and diversion cofferdam works on the right side of the river is a critical activity following mobilisation. Diversion channel excavation and construction of the right-side cofferdams are programmed to be undertaken in the period between the 2012 and 2013 flood seasons. Phase 1 diversion into the left side channel will be achieved in the first quarter of 2013 but cofferdam raising and deepening of the diversion channel will continue to mid 2013 in preparation for the 2013 flood season.

Phase 2 river diversion from the left to the right side of the river channel, allowing the dam works to proceed, will occur after the spillway and powerhouse substructures are substantially complete. Phase 2 diversion will commence after the 2015 flood season with the removal of the right-side cofferdams and launching left-side cofferdams from the left bank. Diversion to the right side will be achieved during the dry season by the first quarter of 2015 but cofferdam raising will continue until mid 2015 in preparation for the 2015 flood season.

The cofferdams will be temporary rock and earthfill structures on largely submerged unprepared alluvium foundations. The cofferdam material will be selected site arising granular fill pushed into place by bulldozer. If it proves necessary to reduce the permeability of the cofferdams to reduce pumping costs, the cofferdams and their insitu alluvium foundations can be jet grouted or diaphragm walled down to bedrock.

It is anticipated that a total of 426 000 m^3 of cofferdam fill will be placed over the two diversion stages.

Dam

Two types of embankment dam are employed. The main dam located in the left half of the river channel will be a concrete-faced rockfill dam (CFRD). The relatively low extension that continues over the right flank will be an earthfill / rockfill dam having rockfill shoulders and an impervious clay core protected by granular filters or transition material. A wholly concrete-faced rockfill dam involving intricate perimetric toe plinths and seals is uneconomic for a low structure. The clay core material however will require stockpile conditioning and close monitoring of moisture content during placement. Both types of dam will require foundation treatment in the form of consolidation and curtain grouting. A concrete gravity-section transition structure will be constructed on the left bank at the interface of the CFRD and the earth / rockfill dam.

The total volume of embankment dam rockfill is expected to be 2 285 000 m^3. The rate of fill placement on the left flank is not critical but placement in the river channel needs to be completed over 12 months between the completion of diversion in the first quarter of 2015 and the first quarter of 2016 to allow the concrete facing to be completed in time to impound the 2016 flood. This requires an average fill placing rate of 150 000 m^3 per month, which translates to 6000 m^3 per day.

Slipforming the reinforced concrete facing can commence at the beginning of 2016 and must be completed and matured when impounding commences. The total volume of concrete is anticipated to be some 57 000 m^3. Placement over 4.5 months equates to an average of 500 m^3 per day.

An unreinforced concrete gravity-section dam completes the river closure between the powerhouse and the right bank. The structure must be completed prior to the removal of the right-side cofferdam and diversion through the spillway at the beginning of 2015. The volume of mass concrete is 50 000 m^3. Placement rate is not critical, construction over 4 months requires an average placement rate of 500 m^3 per day.

Spillway

The spillway works area will become available for construction following Phase 1 diversion in the first quarter of 2013. The spillway structure must be sufficiently complete to safely pass Phase 2 dry season diversion flows by the beginning of 2015 and flood season flows by mid 2015. In this period the reinforced concrete structure must be completed to the extent that the road bridge over the piers is complete, upstream and downstream stoplogs are fully operable in all stoplog slots, and the embedded radial gate components are in place and fully concreted. The radial gates installation should ideally be completed in the same period but their installation could be extended post Phase 2 diversion, to be installed in dewatered bays between upstream and downstream stoplogs.

The spillway bridge will comprise pre-stressed concrete beam sections with an in-situ concrete deck, spanning between the spillway gate piers. The reinforced concrete spillway piers will contain built-in parts for bridge bearings, gate servomotor and trunnion beam anchorages. The pier walls will contain built-in parts for stoplog and radial gate guides and seals. The components will typically be fixed to anchorages built into first stage concrete, aligned, then embedded into second stage concrete. The spillway bridge will be erected in advance of the radial gates, allowing mobile cranes to traverse the spillway and set-up above the gate piers for erection of the 12 nr. radial gates. At Phase 2 diversion the bridge will provide the only means of access onto the adjacent powerhouse structure.

The anticipated volumes of soft and rock excavation are 180 000 m^3 and 115 000 m^3 respectively. Excavation periods of some 1.5 and 2.5 months, based on 150 000 m^3 of soft per month and 50 000 m^3 of rock per month respectively, can be undertaken concurrently in different areas.

The anticipated volume of reinforced concrete is some 150 000 m^3, placed in 12 months at an average rate of 500 m^3 per day. Reinforcement quantities are estimated to be 10 000 tonnes.

Combined Intake and Powerhouse Structure and Tailrace Channel

The works area for the combined intake and powerhouse structure, (the powerhouse) will become available for construction following Phase 1 diversion in the first quarter of 2013. The powerhouse substructure must be sufficiently complete for adequate stability against flotation, sliding and overturning, and capable of being made watertight, when the Phase 2 diversion inundates the powerhouse and spillway works area at the beginning of 2015.

Excavation of the powerhouse and tailrace channel will commence in the first quarter of 2013 as soon as cofferdamming and dewatering permits. Excavation will initially be concentrated in the powerhouse area to enable powerhouse concreting to commence as soon as possible. The anticipated total volumes of soft and rock excavation are 290 000 m^3 and 655 000 m^3 respectively of which 67 000 m^3 and 243 000 m^3 occur in the immediate vicinity of the powerhouse. Excavation periods will be some 2 and 13 months, based on excavation rates 150 000 m^3 of soft per month and 50 000 m^3 of rock per month respectively; with parallel soft and rock working in the powerhouse and tailrace being undertaken concurrently.

Concrete work in the powerhouse is scheduled to start in mid 2013 commencing with the Stage 1 powerhouse structure.

The powerhouse substructure describes the elements from the foundations to the operating deck, the superstructure describes the elements above operating deck such as crane beams and columns and the powerhouse roof. Stage 1 substructure concrete comprises the external walls, piers and slabs that will be in place prior to the installation of the turbine and generator units. Stage 2 substructure concrete includes the concrete embedding the draft tube bend, the turbine spiral concrete, and the concrete supporting the generator that stands above it.

The Stage 1 structure will contain built-in parts for screen and gate guides, gate sealing frames, gate servomotors, dogging beams etc. The mechanical components will typically be fixed to anchorages built into primary concrete, aligned, then embedded into secondary concrete.

When Phase 2 diversion occurs, the Stage 1 substructure must be complete to the extent that the structure is accessible from the right bank, ready to receive the electro-mechanical plant at Stage 2, and watertight above maximum flood level. It requires the road bridge over the intake piers to be in place, the removable intake trash screen and intake stoplogs to have been tested, confirmed interchangeable, fully operable in all slots and installed in their closed position, the intake guard gates to be operational and installed in their closed position, the draft tube stoplogs confirmed fully operable in all slots, and installed in their closed position. Sufficient stoplogs are required to isolate all eight unit bays simultaneously.

The powerhouse superstructure will be completed next, before the commencement of Stage 2 substructure works, to provide a weathertight and dustproof enclosure with cranage for the assembly and erection of the hydro-mechanical and electromechanical plant.

Stage 2 concreting includes the embedment of the draft-tube bend steel liners, the formation of the turbine spiral waterways above the draft tube bends and the embedment of the turbines, which will be subject to special placing restrictions to minimise concrete pressure and flotation forces that would result in displacement of linings and embedded parts. The duration of Stage 2 concreting including the generator foundations and generator barrel is largely controlled by electromechanical plant erection and is expected to be about 6 months per unit, with a 2 month interval between units.

The combined volume of Stage 1 and Stage 2 concrete is approximately 225 000 m^3 of which Stage 1 forms by far the greater proportion. Concreting of the Stage 1 substructure will take approximately 18 months at an average placing rate of 500 m^3 per day. Concrete placing will be by conveyor or mobile pumping units. Reinforcement is estimated to total some 23 500 tonnes.

Commissioning of units will commence in the last quarter of 2016, after the floods, when the reservoir has filled to full supply level. All eight turbine generator units will have been installed by this time and will have undergone dry pre-commissioning tests several months earlier as they became available. Final commissioning will be carried out on a unit-by-unit basis at one month intervals, and each unit will commence generation as soon as possible after commissioning to maximise revenues. Commissioning will require that the waterway for the unit being commissioned is fully functional, including full commissioning of the intake stoplogs, intake guard gates and the draft tube stoplogs. Commissioning also requires that the substation is complete with a functioning connection to the Sudanese grid.

Power Transmission System

The transmission works are non-critical in terms of the overall programme but should be carried out in good time to avoid any risk of delay and to allow backfeed of power for plant testing and commissioning.

Overall Construction Programme and Critical Path

As shown on Drawing D12, the overall implementation programme covers 6 years and 4 months. The construction period following award of the preparatory works contract is 5 years and 8 months. The construction period following award of the main contract is 4 years and 8 months. The first unit will be available for commercial operation 7 months before the end of construction.

The critical path is shown to be through the contracting phase, diversion works, the powerhouse and spillway civil construction and associated E & M equipment installations.

9. GENERATION EXPANSION PLANNING AND ECONOMIC ANALYSIS

9.1 OBJECTIVE

The overall objective of generation expansion planning was to evaluate the benefits for the region (Egypt, Ethiopia and Sudan) provided by an interconnection of the three power systems according to various level of integration (or coordination) of these systems. This Section summarises the results of the generation expansion planning study. The full generation expansion planning study which was carried out as Module 6 of the Eastern Nile Power Trade Study is presented separately.

Accordingly the generation expansion planning has covered:

- determination of least-cost generation expansion plan for the three isolated systems,
- determination of least-cost generation expansion plan for the coordinated system,
- determination of the least cost interconnection option in terms of technology,
- transmission system analysis,
- recommendation of a Regional Investment Program.

The generation expansion planning has been carried out using the SDDP and OPTGEN commercial software packages.

SDDP,is a hydrothermal dispatch model with representation of the transmission network used for short, medium and long term operation studies. The model calculates the least-cost stochastic operating policy of a hydrothermal system, taking into account the following aspects:

- Operational details of hydro plants (water balance, limits on storage and turbined outflow, spillage, filtration etc.)
- Detailed thermal plant modeling (unit commitment, "take or pay" fuel contracts, concave and convex efficiency curves, fuel consumption constraints, multiple fuels etc.)
- Representation of spot markets and supply contracts.
- Hydrological uncertainty: it is possible to use stochastic inflow models that represent the system hydrological characteristics (seasonality, time and space dependence, severe droughts etc.) and the effect of specific climatic phenomena such as the El Niño.
- Detailed transmission network: Kirchhoff laws, limits on power flows in each circuit, losses, security constraints, export and import limits for electrical areas
- Load variation per load level and per bus, with monthly or weekly stages (medium or long term studies) or hourly levels (short term studies).

Besides the least-cost operating policy, the SDDP model calculates several economic indexes such as the spot price (per submarket and per bus), wheeling rates and transmission congestion costs, water values for each hydro plant, marginal costs of fuel supply constraints and others.

OPTGEN is a computational tool for determining the least-cost expansion (generation and interconnections) of a multi-regional hydrothermal system. It represents details of the system operation taking into account inflow uncertainties, emission constraints, and minimum capacity constraints, among other features. OPTGEN has a built-in feature for joint use with SDDP.

9.2 METHODOLOGY

9.2.1 Minimizing Regional Costs

The benefits for the region resulting from the interconnection will be evaluated by the comparison of two situations:

S1: independent development of the three power systems assuming the presence of no interconnection, this situation would lead to the determination of one investment program for each system : P_{Egypt}, $P_{Ethiopia}$, P_{Sudan}.

S2: development of the three power systems assuming the presence of an interconnection and various level of coordination between the power systems. This would lead to the determination of a coordinated investment program $P_{Intercon}$.

The benefits would be given by the difference of costs between these two situations:

Benefits from the interconnection = Cost [P_{Egypt}, $P_{Ethiopia}$, P_{Sudan}] – Cost [$P_{Intercon}$]

9.2.2 Economic Power Trades

Economic power trades are justified by the cost differences of power generation units in neighbouring countries and the objective of minimising the global fuel cost. The presence of an interconnection allows to supply one country at some particular moment with lower cost generation units available in other country. This supply may not be continuous, and may vary in direction and level according to the nature of the power mixes (demand variation, hydrology, etc).

In the present economic study the amount of power trade between Egypt, Ethiopia and Sudan, and the resulting benefits for the region, have been assessed according to two approaches: tight pool model and loose pool model. These two models described hereafter, can be understood as two different stages of development of a power market.

9.2.3 Loose Pool model: coordination of generation operation

In the loose pool model, the generation investment is the same as when the power systems are left isolated. In other words, each country keeps the ability to be self-sufficient and cover its own peak demand. The GEP of each country remains identical to the ones without interconnection. The operation is coordinated on a regional basis (or regional dispatch centre) on the global merit order, within the limits set by the interconnection capacities.

The loose pool model represents the first stage of development of a regional power market providing the relevant price signals for operation (spot market and market for forwards within the current year). The resulting saving is a global reduction of operation costs (main fuel costs).

9.2.4 Tight pool model: coordination of generation investment and operation

A fully integrated regional power system would lead to the lowest cost for the region. In this theoretical situation, all the interconnected power mixes would be operated as a single one, on the basis of a global (i.e. regional) merit order (i.e. from least cost to the most expensive generations units) from a single dispatch centre. At any partial moment (hour, day, year) the total demand would be supplied by the lowest cost generation unit available in the region.

Furthermore, in this model, the investment generation expansion plan would be also optimised at a regional level allowing to take advantage of the countries complementary resources (low cost hydro generation in a country, low cost thermal generation in another, etc).

In a nutshell, operation and investment are coordinated in the tight pool model. Of course, even in this theoretical case some part of the generation would be still dispatched on a non economic basis (e.g. irrigation), and the transmission and distribution network would set limits to amount of power exchanges possible between the different areas.

This tight model can be understood as a representation of a regional mature power system providing the relevant price signal for:

- operation decision: through the existence of a spot market and a forward market, the actors decide whether to buy energy on the market or operate their own generation units,
- investment decision: through the existence of a forward market with a relevant time horizon (>3 to 4 years), the choice whether to buy now energy delivered in next years, or investment in their own new generation units.

This regional operation and investment regional optimisation (or coordination) would result in:

- operation cost savings (expensive fuel in one country would be substituted by lower cost generation fuel available in another country),
- investment savings (the commissioning of some "expensive" plants might be postponed if firm capacity is available from another country through the interconnection, leading to a larger development of lower cost generation in another country).

9.2.5 Summary Table

Table 9.1 : Tight and Loose Pool Models - Main Characteristics

Model	Level of coordination	GEP	Savings
Isolated system	No	GEP Egypt, GEP Ethiopia, GEP Sudan	Reference situation
Loose pool model	Operation	Idem as above	Fuel costs
Tight pool model	Operation and investment	Updated GEP	Fuel costs and investment costs

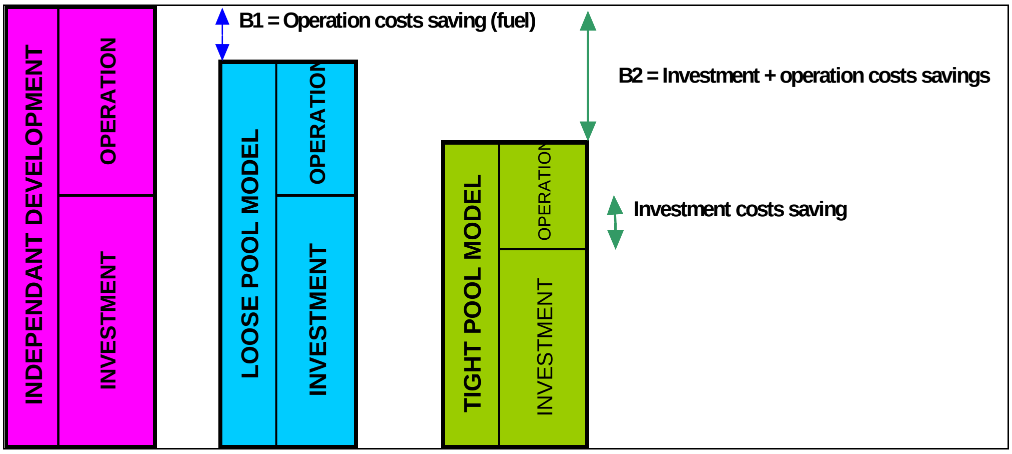


Figure 9.1 : Savings from Tight and Loose Pool Models

9.2.6 Point of View of the Economic Analysis

In the generation planning, the point of view of the economic analysis is regional, meaning the objective is to measure the global benefit (i.e savings) for the three countries, and not the benefits specifics for each country.

A cost approach is considered (including externalities e.g. non-energy benefits and mitigation costs). The global (and real) cost for the region is evaluated and considered. What is evaluated and analysed is the modification of the global cost (generation investment, interconnection investment, operation cost) with and without interconnection. This means, for example, that the share of cost of projects (interconnection or HPP) between the different countries is not considered or relevant at this stage, because it does not change the global cost of investment for the region.

Subsidies to fuel are not considered either, nor duty or taxes, or the selling price of energy for the same reason. In the same way, the allocation of the benefits to the different stakeholders is not relevant. In other words, the possible selling price of power and wheeling tariff are not relevant in the economic analysis.

In this way, the global benefits (i.e. the global cost reduction) for the region could be evaluated. As a result, the economic study will evaluate the potential benefits for the region according to various options (interconnection, power pool models, etc).

9.3 COMPARISON OF ECONOMIC GENERATION COSTS IN THE THREE POWER SYSTEMS

A view of the generation costs in the region can be acquired through the analysis of:

- the economic cost of generation (or levelised cost of generation, which includes fixed and variable cost of generation),
- the variable cost of generation (which includes solely the part of cost dependant on the amount of generation.

The first approach is pertinent when generation investments are specifically decided for export purposes, in substitution for new possible investments in the importing country.

The second approach is pertinent when investments are decided only for the requirement of internal demand, and if surplus are available for exports, in substitution for more expensive generation in the importing country.

9.3.1 Comparison of the Economic Costs of Generation

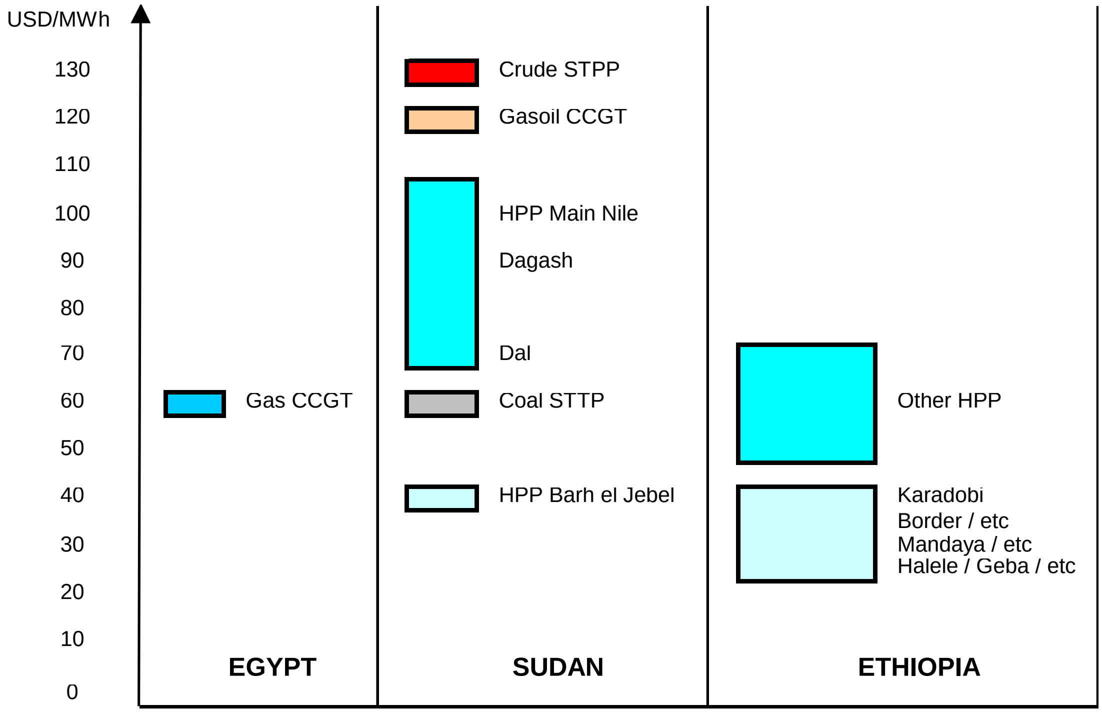


Figure 9.2 : Comparison of the economic cost of generation in different generation mixes - Year 2020 - Medium fuel price scenario - 10% discount rate

This cost evaluation has been done on the basis of international market fuel price projection (because the purpose of the Study is the evaluation of power exchanges) which might be very different than the present fuel cost paid by the National Utilities. The figure above is based on year 2020, medium fuel price projection and TPP with load factor from 5 000 to 6 000 hours/year.

From the most cost effective projects to the more expensive it was found that:

- the lower cost generation projects are composed by a group of Ethiopian HPP projects (Halele, Geba, Karadobi, Mandaya, Border etc) with economic cost from 25 to 40 USD/MWh;
- then close to 40 USD/MWh we found the Bahr el Jebel HPP project in South Sudan;
- then close to 60 USD/MWh, we found CCGT in Egypt, coal-fired STPP in Sudan (but the number of coal-fired STTP is Sudan is limited by transmission capacity), and a group of hydro projects in Ethiopia;
- then from 70 to 110 USD/MWh, we find the HPP projects in the Main Nile river in Sudan including projects;

- finally, the most expensive units are gas oil-fired CCGT and crude oil-fired STPP is Sudan.

Accordingly, considering cost and power surplus, the bulk of power export will come from cost effective HPP projects in Ethiopia (all cost effective hydro power in Sudan being absorbed by Sudan internal demand).

The Sudanese power mix is clearly the destination of the bulk of power exports considering the high generation costs.

Power export from Ethiopia to Egypt are profitable, but provide less economic advantage than from Ethiopia to Sudan considering the lower cost difference and the greater transmission cost.

9.3.2 Comparison of the Variable Costs of Generation

While the economic cost of generation (related to what is often called long term marginal cost of generation) includes investment and operation costs, the variable cost (related to what is called short term marginal cost) only includes fuel and variable O&M cost.

The following table compares, for year 2020, and for the high fuel price projection (crude oil = 89 USD/bbl, to be compared to the current market price 78 USD/bbl in September 2007), the economic cost and the variable cost of generation for the main TPP candidates:

Table 9.2 : Comparison of economic and variable costs of generation – Year 2020 – High fuel price projection – 10% discount rate

	Economic cost (6000 hrs/year) USD/MWh	Variable cost USD/MWh	Ratio Var. cost / Economic cost
(Egypt) gas-fired 750 MW CCGT	68	52	74%
(Sudan) 500 MW gasoil-fired CCGT	179	164	92%
(Sudan) 500 MW crude-oil fired STPP	182	154	85%
(Sudan) coal-fired STPP	57	28	50%

It is notable that the variable cost represents most of the generation cost of CCGT and STPP (between 75 to 92%). This proportion increases in time along with the general increase of fuel prices. It also means that most the future savings resulting from power trade will come from fuel savings (an not investment savings).

9.4 GENERATION EXPANSION PLAN FOR THE ISOLATED SYSTEMS

The following paragraphs present the main characteristics of the first version of the least cost generation expansion plan of the three isolated systems (i.e. with non interconnection between them).

9.4.1 Egypt

Main hypothesis:

- Medium demand projection (5.6% average annual growth rate),
- Medium fuel price projection (crude oil 60 USD/bbl, NG = 8.6 USD/MBTU in 2030).
- Power export to Jordan (200 MW) and Libya (200 MW).
- No exchange with Sudan or Ethiopia.

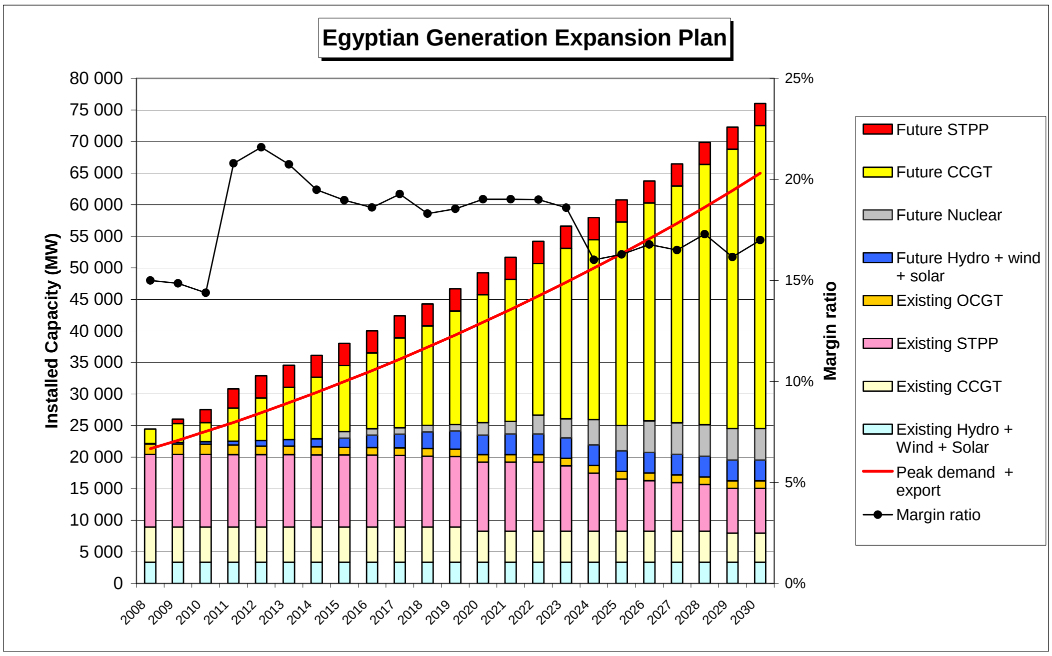


Figure 9.3 : Generation Expansion Plan – Egypt – No interconnection with Sudan / Ethiopia

9.4.2 Ethiopia

Main hypothesis:

- Medium demand projection (average annual growth rate 10.9%).
- Medium fuel price projection (crude oil 60 USD/bbl in 2030),

- No exchange with Egypt or Sudan.
- Power export to Kenya (from 200 MW in 2011, 600 MW in 2020, and 1200 MW in 2030)
- Power export to Djibouti (<53 MW).

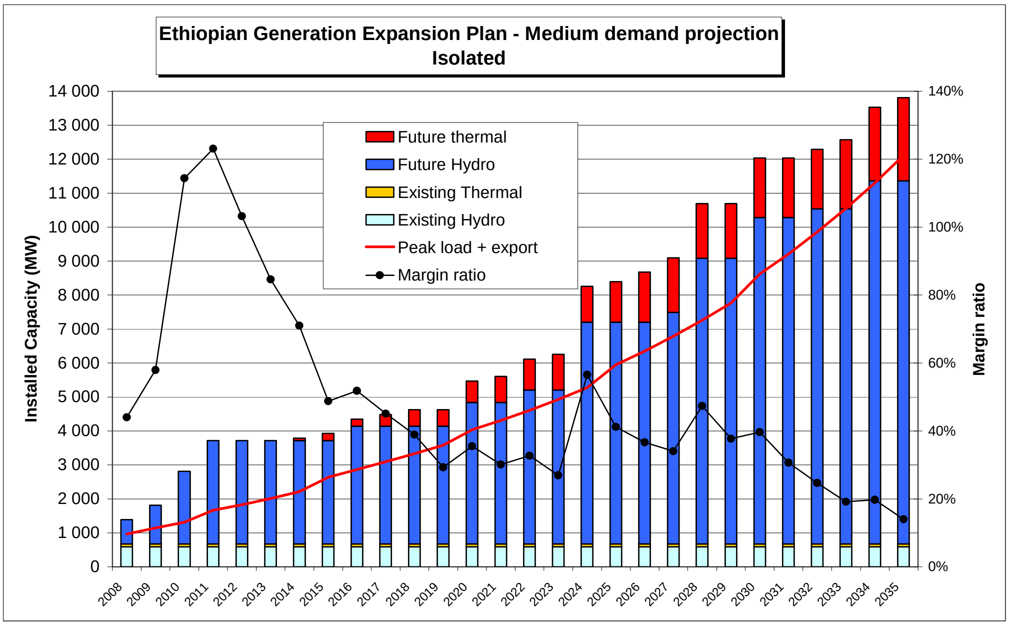


Figure 9.4 : Generation Expansion Plan - Ethiopia - No interconnection Sudan / Egypt

The associated schedule of HPP commissioning is the following:

Table 9.3 : Generation expansion plan - HPP Ethiopia

Commisioning Date	Hydro Project	Capacity MW	Average Generation GWh	TPP	Capacity MW
2008	Gibe II	420	1 600		
	Tekeze	300	1 200		
2009	Beles	420	2 000		
2010	Neshe	97	225		
2011	Gibe III (I)				
2012	Gibe III (II)	1 870	6 240		
2014				OCGT	70
2015				OCGT	140
2016	Halele Worabesa	420	2 245		
2017				OCGT	140
2018				OCGT	140
2019					
2020	Baro I + I + Gengi	700	4 409	OCGT	140
2021				OCGT	140
2022	Geba I + II	368	1 788	OCGT	140
2023				OCGT	140
2024	Mandaya	2 000	12 100		
2025				OCGT	140
2026				OCGT	280
2027	Chemoga Yeda	280	1 415	OCGT	140
2028	Karadobi	1 600	6 000		
2029					
2030	Border	1 200		OCGT	140
2031					
2032	Genale III	254			
2033				OCGT	280
2034	GenaleIV - Aleltu E&W	569		OCGT	140
2035				OCGT	140
Total		10 498			2 310

From 2010 to 2014, Ethiopia can take advantage of a significant surplus of hydro generation which can be exported to Sudan through the future 200 MW Ethiopia – Sudan interconnection.

9.4.3 Sudan

Main hypothesis:

- Medium demand projection (average annual growth rate 9.8%).
- Medium fuel price projection (crude oil 60 USD/bbl in 2030).
- No exchange with Egypt or Sudan.

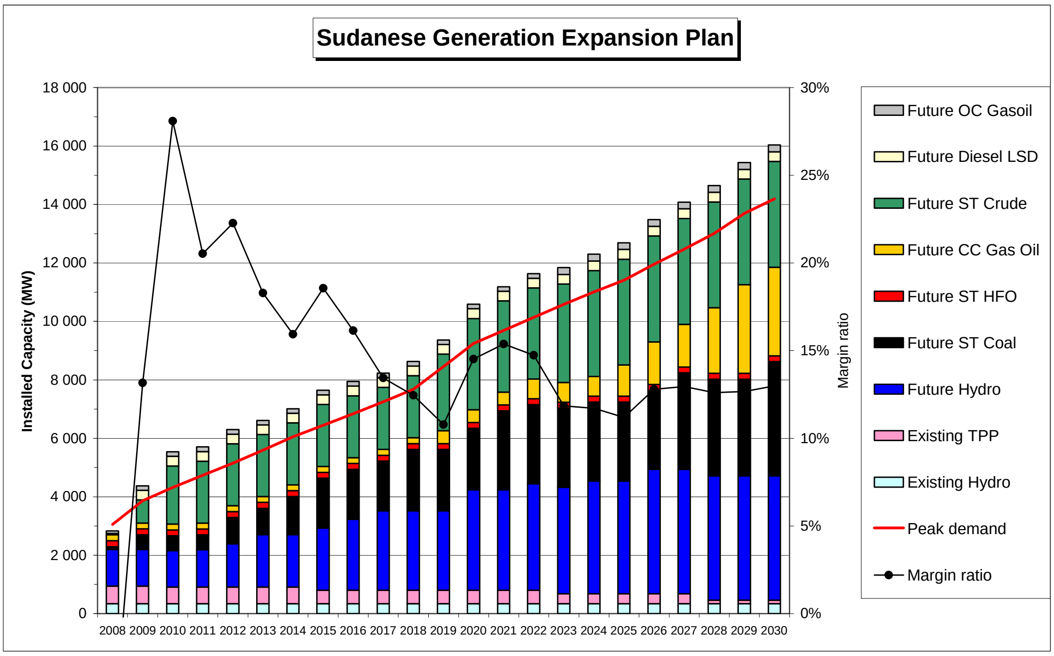


Figure 9.5 : Generation Expansion Plan – Sudan

9.5 LOOSE POOL MODEL: POWER EXCHANGES & REGIONAL SAVINGS

The loose pool model refers to a scheme where the operation of the generation is coordinated regionally (either by direct coordination or through a power pool) while each country keeps its independence for the decision of generation investment. Accordingly, the investment cost of the regional generation plan is identical as in the independent development of each power system, while the operation cost is reduced through regional coordination and the use of Ethiopian hydro surplus. This approach is similar to the one carried out for the Ethiopia – Sudan Interconnection Study (2005).

The operation optimization software SDDP allows to simulate the optimal operation (i.e. least cost dispatch) of the integrated system according to the capacity of the interconnection.

9.5.1 Origin of the Hydro Surplus

Basically, the hydro surplus in Ethiopia are inherent to the development of a purely hydro system based on large size HPP for two reasons:

- Due to the large size of Ethiopian HPP projects compared to the Ethiopian internal demand (e.g. Mandaya represents more than 1/3 of the Ethiopian demand in 2024), hydro power surpluses are available for export during the first years following the commissioning of these large HPP projects, during the period of time when the Ethiopian demand does not completely absorb the new generation. Smaller projects would be included at a quicker step in the Ethiopian GEP, and would be absorbed more rapidly by the demand growth, and would result in much less hydro surplus, but would lack the economic competitiveness of largest HPP projects.

- In a hydro power system, in order to have a proper supply / demand balance all year long and even on the driest years, a large amount of installed overcapacity is required.

The resulting hydro surplus, can be provided for export, when available, at no additional cost for the Ethiopian power system.

9.5.2 Characteristics and Costs of the Hydro Surplus

The amount of hydro surpluses is variable with the planting of new hydro plants (reaching maximum on the commissioning of large HPP, and minimum before new commissioning), and during each year (higher during wet season).

All the hydro project investment decisions are justified by the internal demand requirement. In other words, the supply of power export is made at no additional cost for the hydro exporting country[1].

Finally, hydro surplus are available on the average at no additional cost, but are variable in amount and duration.

This type of power exchanges is typical of spot market and future market (month to month). For instance, after the wet season Ethiopia could assess the amount of stored energy in its reservoirs and evaluate the amount available for export and contract exchange for a period of a few months.

9.5.3 Reference Situation

The reference situation for the evaluation of the operation savings is characterized by:

- commissioning of the Ethiopia-Sudan 200 MW interconnection in 2010,
- generation expansion plans of Egypt, Ethiopia and Sudan identical to those determined without any interconnection.

In order to determine the savings related only to the new interconnection (and not to the 200 MW Ethiopia Sudan interconnection), the savings described below are relative to this reference situation.

9.5.4 Earliest Date of Commissioning of the Interconnection

Based on the duration of technical studies, tender process and construction, the earliest date of commissioning of the interconnection is close to 2015.

[1] Obviously, this does not mean the selling price must be null. On the opposite, the selling price is to be negotiated of the basis of the sharing of the global savings between the exporting country and the importing country.

However, it makes more sense to link the commissioning date of the interconnection with the commissioning of the first large HPP project close to Sudan (i.e. Mandaya). In the isolated development of the Ethiopian system, Mandaya is commissioned in 2024. In the scenario with interconnection, it is considered that Mandaya is commissioned at its earliest date of commissioning: 2020 and this same date of commissioning is considered for the interconnection. This 4 years shift forward is the only difference with the Ethiopian generation expansion plan determined previously without interconnection. In the evaluation of the generation savings the additional investment cost (anticipation of 4 years) will be taken into account.

9.5.5 Power exchanges for the reference hypothesis

The power exchanges and generation savings have been evaluated for a variety of interconnection capacities. For example, the following figure presents the evolution of the economic power exchanges for a scheme with 1200 MW capacity between Ethiopia and Sudan and 700 W capacity between Ethiopia and Egypt :

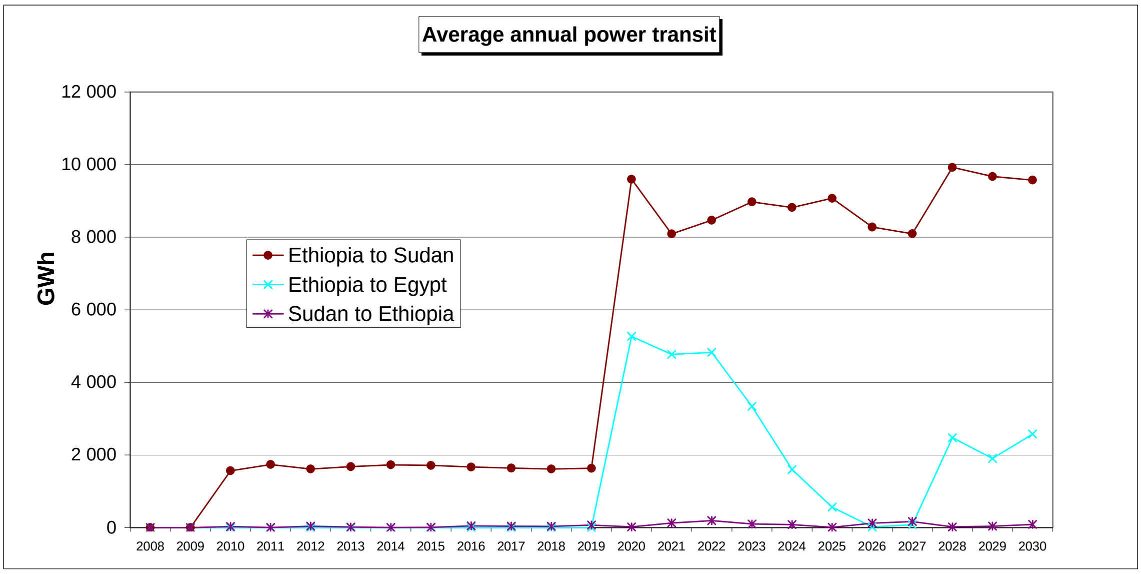


Figure 9.6 : Average Annual Power Transit
– ET-SU=1200 MW – ET-EG= 700 MW – Loose Pool

In order to minimize the regional operation costs, the economic exchanges develop preferably toward Sudan where the fuel savings are higher (because of higher generation cost). The average annual power export from Ethiopia to Sudan, arises to 9 000 GWh/year over the 2020-2030 period, and nearly saturates the 1 200 MW capacity continuously.

The average annual power export from Ethiopia to Egypt, arises to 2 500 GWh/year over the 2020-2030 period, peaking during the first years after commissioning Mandaya (2020), Karadobi (2028) and Border (2030).

9.5.6 Sensitivity Analysis

The basic principle in the sensitivity analysis is to change one single key hypothesis of the Study at a time to check its impact on the results.

A number of analyses could be carried out, the focus here is to check how much the global savings for the region are affected by adverse evolution of key hypothesis. The potential negative factors are:

- lower evolution of fuel price leading to lower fuel savings,
- higher evolution of the Ethiopian demand, leading to possible less hydro surplus available for export,
- lower evolution of the Ethiopian demand, leading to possible less hydro surplus because of longer time span between commissioning of large HPP.

Low fuel price projection:

The simulations show that the volume of export remains close to the reference situation with medium fuel price projection. The regional fuel cost savings are reduced by about 1/3.

High demand projection for Ethiopia:

With the high demand projection in Ethiopia, the Ethiopia hydro surplus are absorbed more rapidly by the rise of the Ethiopia own demand. The regional fuel cost savings are reduced by about 1/3 compare to the situation with de Medium Ethiopian demand projection.

Low demand projection for Ethiopia:

The simulations show that the volume of export and the regional generation savings remain close to the reference situation with medium Ethiopian demand projection.

9.6 TIGHT POOL MODEL: POWER EXCHANGES & REGIONAL SAVINGS

9.6.1 Introduction

In the tight pool model, the countries coordinate their decision of generation investments, in order to minimize the regional generation cost (investment + operation). The hydro generation investments in Ethiopia are anticipated (compared to the loose pool approach) in order to provide more power available for export to Egypt and Sudan.

Strictly speaking some generation investments could be delayed in Egypt and Sudan due to the increased power import. However, due to the increase of the projected fuel prices all over the period of the Study, the investment represents only 15 to 25% of the total generation cost of new thermal plants. Accordingly, the Consultant would not recommend any modification of the Generation Expansion Plans of Egypt and Sudan, which means these countries would still keep their ability to balance their power demand with their own supply whenever power import are not available (and would not depend on financing / construction / hydrology risks of large HPP projects).

The tight pool approach has been studied for the medium and the low Ethiopian demand projections. Indeed, the generation expansion plan for the high demand projection in Ethiopia (isolated case) gives no room for anticipation of any HPP projects.

9.6.2 Economic Power Exchanges

Medium demand projection for Ethiopia

The following figure presents, for example, the evolution of the economic power exchanges for a scheme with 1200 MW capacity between Ethiopia and Sudan and 2000 MW capacity between Ethiopia and Egypt, and the medium demand projection for Ethiopia:

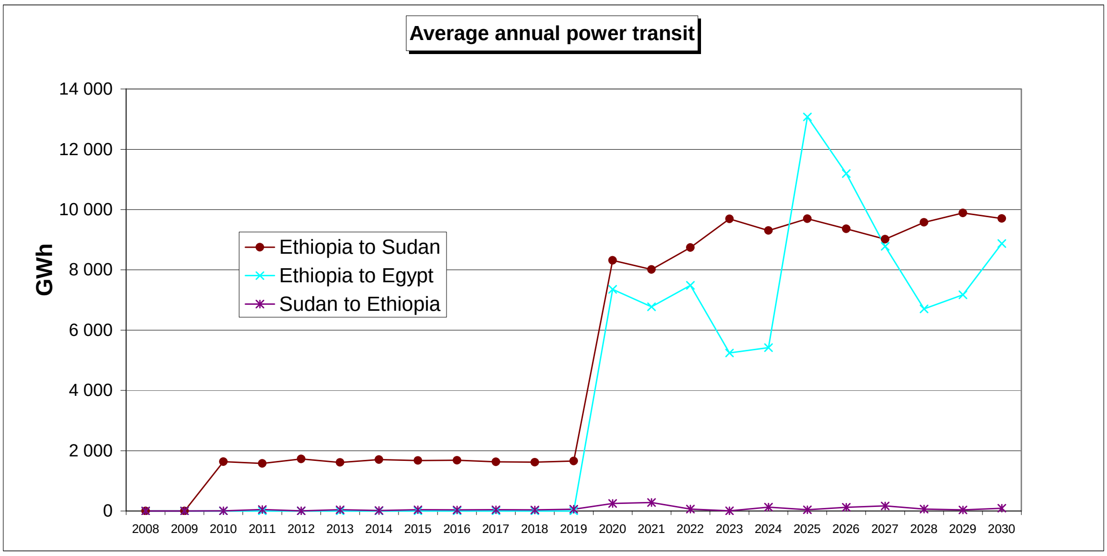


Figure 9.7 : Average annual power transit - ET-SU=1 200 MW, ET-EG=2 000 MW-Tight pool – Medium demand projection for Ethiopia

The increase of power exchange is readily appearing with comparison to the loose pool situation:

- The average annual power export from Ethiopia to Sudan arises to 9200 GWh/year over the 2020-2030 period, and saturates the 1200 MW capacity continuously (equivalent to 7700 h / year at 1200 MW).
- The average annual power export from Ethiopia to Egypt arises to 8000 GWh/year over the 2020-2030 period (equivalent to 4000 h / year at 2000 MW).

The underlying generation expansion plan for Ethiopia includes the following modifications compared to the isolated situation:

- anticipation of Mandaya from 2024 to 2020,
- anticipation of Geba I+I: from 2022 to 2021,
- anticipation of Chemoga Yeda from 2027 to 2022,
- anticipation of Karadobi from 2028 to 2025,
- Genale III enters the GEP in 2022,
- Genale IV enters the GEP in 2023,
- Aleltu East and West enters the GEP in 2029.

The Border commissioning date is left unchanged at 2030 in order to keep a 5-year interval between the commissioning dates of Mandaya, Karadobi and Border, compatible with the reduction of the negative downstream effect during the successive filling of these reservoirs.

Low demand projection for Ethiopia

Apart from the hydro projects identified for Ethiopia in Module 3, other medium scale hydro projects might cover part of the internal Ethiopian power demand. Accordingly, the low demand projection is probably more relevant to the scope of the Study with respect to the amount power that could be exported from Ethiopia.

In these conditions, and for a scheme with 1 200 MW capacity between Ethiopia and Sudan and 2 000 W capacity between Ethiopia and Egypt, the amount of power exchanges to Egypt increases significantly reaching 12 700 GWh/year over the 2020-2030 period (equivalent to 6 300 h / year at 2 000 MW):

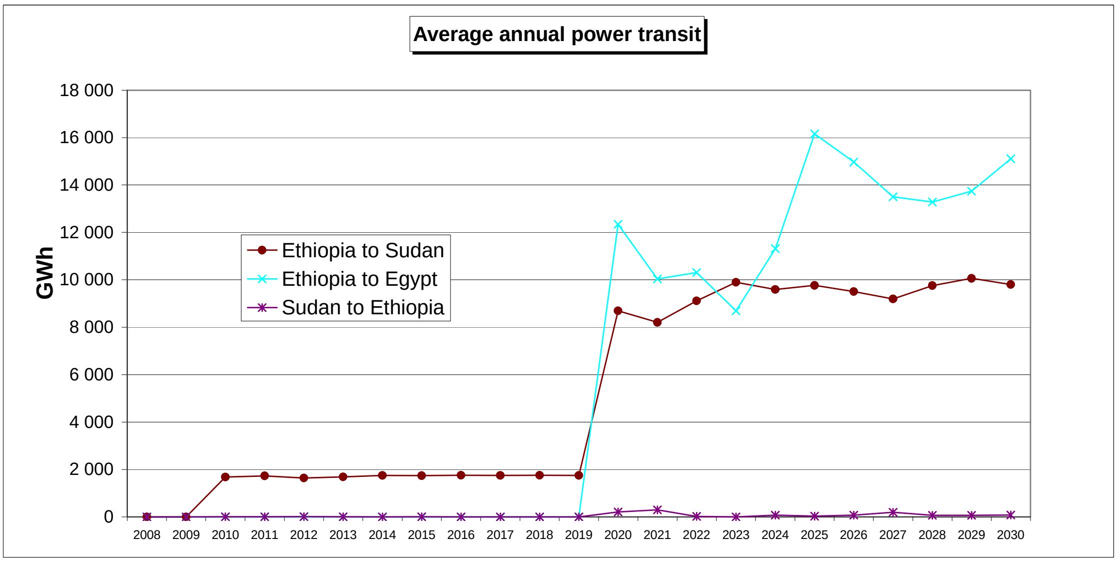


Figure 9.8 : Average annual power transit - ET-SU=1 200 MW, ET-EG=2 000 MW- Tight Pool – Low Demand Projection for Ethiopia

9.7 CO_2 SAVINGS

9.7.1 Loose Pool Model

The following table provides the annual quantity of CO_2 savings in tons, and the present worth value of the CO_2 savings in 2008 based on a 5 and 10 USD/t value:

Table 9.4 : Present Worth Value of CO_2 Emission Savings

			Present worth value					
Case	Additional	CO2	8% discount rate		10% discount rate		12% discount rate	
	export	reduction	5 USD/tCO_2	10 USD/tCO_2	5 USD/tCO_2	10 USD/tCO_2	5 USD/tCO_2	10 USD/tCO_2
	TWh/year	M ton	MUSD	MUSD	MUSD	MUSD	MUSD	MUSD
Ethiopia-Sudan : 700 MW	4.00	3.00	80	161	53	105	36	72
Egypt-Ethiopia : 700 MW	3.60	1.55	41	83	27	54	19	37
Total	7.60	**4.55**	122	244	80	159	54	109
Ethiopia-Sudan : 1200 MW	7.10	5.33	143	285	93	187	64	128
Egypt-Ethiopia : 700 MW	2.00	0.86	23	46	15	30	10	21
Total	9.10	**6.19**	166	332	108	217	74	148

This present worth value would have to be included in the benefits of the project if eligible to Clean development Mechanism (CDM).

9.7.2 Tight Pool Model

In the tight pool model, the additional hydro power from hydro power leads an additional reduction of the CO_2 emissions in Egypt and Sudan as described in the following table:

Table 9.5 : Present Worth Value of CO_2 Emission Savings – Tight Pool Model

Case		Additional export	CO2 reduction	Present worth value					
				8% discount rate		10% discount rate		12% discount rate	
				5 USD/tCO_2	10 USD/tCO_2	5 USD/tCO_2	10 USD/tCO_2	5 USD/tCO_2	10 USD/tCO_2
		TWh/year	M ton	MUSD	MUSD	MUSD	MUSD	MUSD	MUSD
Ethiopia-Sudan :	1200 MW	8.20	6.15	165	330	108	216	74	147
Egypt-Ethiopia :	700 MW	5.20	2.24	60	120	39	78	27	54
Total		13.40	**8.39**	225	450	147	294	100	201
Ethiopia-Sudan :	1200 MW	7.40	5.55	149	298	97	195	66	133
Egypt-Ethiopia :	2000 MW	6.20	2.67	71	143	47	93	32	64
Total		13.60	**8.22**	220	440	144	288	98	197

9.8 ECONOMIC ANALYSIS

The economic consists in comparing the net balance between :

- the cost of the interconnection.
- the "benefits" provided by the interconnection : generation cost savings and CO_2 savings ;

The classic economic criteria "Net Present value" and Benefit to Cost ratio will be used.

9.8.1 Cost of the interconnection

The following table summarizes the present worth cost of interconnection project for the three main options of capacity in MUSD $_{2008}$:

Table 9.6 : Present Worth Value of the Interconnection Cost

SU : 700 MW, EG : 700 MW	SU : 1200 MW, EG : 700 MW	SU : 1200 MW, EG : 2000 MW
407	490	1040

These present worth of costs are calculated on the base of the expenditure schedule of the interconnection and 0% discount rate. This cost includes :

- the cost of the project
- the annual O&M cost.

9.8.2 Loose Pool Model

The following table summarizes the present worth of generation savings for the main options analyzed previously in the loose pool model (10% discount rate):

Table 9.7 : Present Worth Value of Generation Savings - Loose Pool (Million USD)

$\mathbf{MUSD_{2008}}$	SU : 700 MW, EG : 0 MW	SU : 700 MW, EG : 700 MW	SU : 700 MW, EG : 2000 MW	SU : 1200 MW, EG : 700 MW	SU : 1200 MW, EG : 2000 MW
Demand median - Fuel median	1 280	1 910	2 010	2 270	2 380
Demand median - Fuel low	840	1 120	1 340	1 520	1 520
Demand ET low - Fuel median	1 170	1 920	2 260	2 540	2 590
Demand ET high - Fuel median	820	1 140		1 550	1 600

These generation savings (fuel cost reduction from substitution of thermal power by hydro power) results from the coordination of the operation of three generation mixes allowed by the interconnection. These are potential benefits which would be achieved with a fully coordinated operation of the three interconnection power mixes (regional generation dispatch center). The actual benefits would obviously be lower, depending on the nature and importance of the power market, the type of contracts, and the actual level of coordination between the different Utilities.

These generation savings are net of the interconnection transmission losses and from additional investment cost in some scenario (i.e. Mandaya commissioned in 2020 instead of 2024 in the medium demand projection). The present worth value is given in $MUSD_{2008}$ discounted in 2008.

It should be noted that other "non power" benefits resulting from new hydro projects (such as downstream benefits) remain the same whether the interconnection is committed or not.

The following table presents the net savings (savings minus cost) under the loose pool model according to the various capacity options and key parameters of the study :

Table 9.8 : Net Present Value of the Interconnection – Loose Pool Model

NPV ($\mathbf{MUSD_{2008}}$):	SU : 700 MW, EG : 700 MW	SU : 1200 MW, EG : 700 MW	SU : 1200 MW, EG : 2000 MW
Demand median - Fuel median	1 500	1 780	1 340
Demand median - Fuel low	710	1 030	480
Demand ET low - Fuel median	1 510	2 050	1 550
Demand ET high - Fuel median	730	1 060	560

The interconnection Net Present Value is positive for every capacity option and key parameter.

In case of low fuel cost evolution, the profitability of the interconnection would be significantly lower (NPV divided by 2 or 3 depending on interconnection capacity). The same is true if the Ethiopian demand follows the "high demand projection". If the

Ethiopian demand follows the "low demand projection" the results are equivalent to the reference case with the "medium demand projection".

While still positive, the NPV decreases significantly going up to a 2 000 MW (for Egypt) and 1 200 MW (for Sudan) scheme. This is due to the significantly higher cost for the 2 000 MW interconnection link, while additional fuel savings are low because of the main part of the Ethiopia hydro surplus has been provided for export.

Comparing options

The next table provides the Benefit to Cost Ratio (also called BCR) which is a convenient and classic ratio for comparing options:

Table 9.9 : Benefit to Cost Ratio – Loose Pool Model

Benefit / Cost ratio :	SU : 700 MW, EG : 700 MW	SU : 1200 MW, EG : 700 MW	SU : 1200 MW, EG : 2000 MW
Demand median - Fuel median	4.7	4.6	2.3
Demand median - Fuel low	2.7	3.1	1.5
Demand ET low - Fuel median	4.7	5.2	2.5
Demand ET high - Fuel median	2.8	3.2	1.5

The benefit to Cost ratio is equal to the Net Present value of the benefits divided by the Net Present value of the cost. A value greater than one means the benefits outbalances the cost of the project.

The decrease of the profitability of the interconnection is apparent in case of low evolution of fuel costs or if the Ethiopian demand follows the high projection.

On the whole, the option with the higher BCR is the 700 MW (for Egypt) 1 200 MW (for Sudan) scheme.

9.8.3 Tight pool model

Present worth of generation benefits

The following table gives the present worth of generation savings for the main options analyzed previously in the loose pool model (10% discount rate):

Table 9.10 : Present Worth Value of Generation Savings – Tight Pool Model

Present worth of savings (generation) - $MUSD_{2006}$	SU : 1200 MW, EG : 700 MW	SU : 1200 MW, EG : 2000 MW
Medium demand for Ethiopia - Fuel medium -Tight pool	2 810	2 960
Low demand for Ethiopia - Fuel high -Tight pool	3 140	4 020
Low demand for Ethiopia - Fuel medium -Tight pool	2 380	2 990

These generation savings are net of interconnection transmission losses, and of the additional investment costs resulting from the anticipation of several HPP in Ethiopia compared to the loose pool model.

Net savings

The following table presents the net savings (savings minus cost) according the various capacity options and key parameters of the study:

Table 9.11 : Net Present Value of the Interconnection – Tight Pool Model

NPV ($MUSD_{2006}$):	SU : 1200 MW, EG : 700 MW	SU : 1200 MW, EG : 2000 MW
Medium demand for Ethiopia - Fuel medium -Tight pool	2 320	1 920
Low demand for Ethiopia - Fuel high -Tight pool	2 650	2 980
Low demand for Ethiopia - Fuel medium -Tight pool	1 890	1 950

The tight pool approach, along with an increase of power exports, provides an increase of the Net Present Value of the interconnection project for the region.

Comparing options

The next table provides the Benefit to Cost Ratio (also called BCR):

Table 9.12 : Benefit to Cost Ratio – Tight Pool Model

Benefit / Cost ratio :	SU : 1200 MW, EG : 700 MW	SU : 1200 MW, EG : 2000 MW
Medium demand for Ethiopia - Fuel medium -Tight pool	5.7	2.9
Low demand for Ethiopia - Fuel high -Tight pool	6.4	3.9
Low demand for Ethiopia - Fuel medium -Tight pool	4.9	2.9

While the benefit to cost ratio would favors the ET-SU: 1 200 MW – ET-EG: 700 MW scheme, the NPV is equivalent with ET-SU: 1 200 MW – ET-EG: 2 000 MW scheme. Accordingly, this latter scheme is preferable for the region.

9.8.4 Savings per Country and Pay Back Period

The pay-back period is the period of time necessary for the savings (= mainly fuel savings) to balance the expenses (cost of the interconnection and anticipation of HPP investment). At the end of the payback period the present value of the savings is equal to the present value of the expenses.

Loose pool model

For a scheme with a 1 200 MW capacity to Sudan and a 700 MW capacity to Egypt, the interconnection investment is paid after 3 full years of operation (medium demand projection for all countries, medium fuel price projection, 10% discount rate). This very short pay back period is consistent with the high benefit to cost ratio of the interconnection project.

The average export to Egypt would be 2.5 TWh/year, with 130 $MUSD_{2006}$/year average fuel savings, while the average export to Sudan would be 9 TWh/year, with an average fuel savings of 750 $MUSD_{2006}$/year (450 $MUSD_{2006}$/year from crude oil and 210 $MUSD_{2006}$/year from gasoil).

Tight pool model

For a scheme with a 1 200 MW capacity to Sudan and a 2 000 MW capacity to Egypt, the interconnection investment is paid after 6 full years of operation (medium demand projection for all countries, medium fuel price projection, 10% discount rate).

Whenever the Ethiopia demand follows the low demand projection (or if additional low cost Ethiopian HPP projects are identified) the pay back period would be 7 years.

The average export to Egypt would be 12.7 TWh/year, with 680 $MUSD_{2006}$/year average fuel savings, while the average export to Sudan would be 9.4 TWh/year, with an average fuel savings of 750 $MUSD_{2006}$/year.

9.8.5 Analysis

The interconnection project is characterized economically by a good profitability, a short payback period and a high benefit to cost ratio.

Loose pool model

The loose pool model, which consists basically in exporting the hydro surplus inherent to the Ethiopian power system (at no additional cost for Ethiopia), is characterized by:

- some variability of the amount exported power to Egypt (export to Sudan being more base-load) along the period of study,

- lower amount of power export (compared to the tight pool approach), but with the advantage of low HPP additional investment cost (the only additional investment cost is the anticipation Mandaya from 2024 to 2020 in time with the commissioning of the interconnection[2]).

Accordingly very good BCR and short payback periods are achieved, the variability of the hydro surplus being balanced by the low global additional generation investment cost.

This model is typical of the actual power exchanges between European countries (spot market, month to month exchanges) which take benefits of temporary (short to medium term) power surplus in one or other country.

In this context, the best scheme, from a strictly economic point of view, would be ET-SUD: 1 200 MW ET-EG: 700 MW, with a benefit to cost ratio of 4.5 and a very short 3 year-payback period.

However, going to 2 000 MW capacity to Egypt would still be profitable for the region (BCR=2.3), and would give more freedom and flexibility for a future evolution to a tight pool model, and in a latter stage to an extension of the market to Kenya and SAPP.

Tight pool model

In the tight pool model adopted in this Study, HPP investments in Ethiopia are anticipated (with respect to their schedule when Ethiopia remains isolated) in order to provide an additional amount of power export. Thus, the power exports arise for one part, from the "natural" hydro surplus inherent to the Ethiopian hydro generation mix, and for the other part from the anticipation of some Ethiopian HPP.

The generation expansion plans of Egypt and Sudan are left unchanged because, due to the projected fuels price increase all over the period of the Study, the investment represents only 15 to 25% of the total generation of new thermal plants. Accordingly, the Consultant would not recommend any modification of the Generation Expansion Plans of Egypt and Sudan, which means these countries would still keep their ability to balance their power demand with their own supply whenever power import are not available.

The tight pool model is characterized by:

- increased amount of exports (compared to loose pool),
- lower variability of the power export to Egypt along the period of study,
- at the expense of higher generation investment cost in Ethiopia.

Accordingly the BCR and payback period is lower than in the loose pool model, but still very good.

[2] For the Ethiopian low demand projection, Mandaya is anticipated from 2025 to 2020, while for the high demand projection no anticipation is required because the "natural" date of commissioning of Mandaya is 2020.

The best scheme, on the basis of the Ethiopian HPP listed in Module 3, and from a strictly economic point of view, would still be ET-SUD: 1 200 MW ET-EG: 700 MW.

However, the Net Present Value of the scheme with ET-EG: 2000 MW being very close to the scheme with ET-EG: 700 MW. Going to 2 000 MW is certainly preferable, the pay back period is still short (6 to 7 years according to hypothesis considered), and giving more flexibility for the evolution of power trade in the future.

9.9 SUMMARY OF ADVANTAGES / DISADVANTAGES RESULTING FROM THE INTERCONNECTION PROJECT

The purpose of the present economic Study was to evaluate the potential economic benefits resulting from the interconnection project. While these benefits can be evaluated in terms of monetary values, they do not represents all the possible benefits resulting from the project. In order to widen the view, the following simplified tables summarizes for the region and for each country, the main advantages and the disadvantages from the interconnection project. In order to be more specific, the tables indicated what is the origin of the advantages or disadvantages:

- Electric market: when the advantage/disadvantage exists if and only if the interconnection exists.
- HPP projects in Blue Nile River: when the advantage/disadvantage exists even in the absence of the interconnection (e.g. large HPP project on Blue Nile in Ethiopia is necessary to the Ethiopian system even without interconnection, accordingly the positive downstream impacts are related to the HPP project and not to the interconnection).

9.9.1 Region

Table 9.13 : Advantages / Disadvantages for the Region

Origin	Advantages
Power market	Creation of a power pool: - global generation cost savings, - reduction of the cost of electricity for the final user would favor overall development, - economies of scale in new generation capacity : development of larger low-cost hydropower plants made possible through the creation of larger power market, - hydro-thermal complementarity between Egypt, Ethiopia and Sudan, - mutual assistance in case of disturbances, - first step to the connection of the North Africa power systems to the South East African power pool. Regional cooperation, trust building and coordinated development of Nile Basin
Hydro projects	Coordination of the operation of HPP on the Nile river for an overall benefit for the region. Regulation of inflows and continuous availability of water. Reduction in CO_2 emissions

Origin	Disadvantages
Power market	None

9.9.2 Egypt

Table 9.14 : Advantages / Disadvantages for Egypt

Origin	Advantages
Power market	Fuel savings (mainly Natural gas). Reduction in CO_2 emission. Securisation of the long term cost of generation (hydro power base import have a generation cost independent of the variation of crude oil price). Possibility for Egyptian generator companies to invest in low-cost hydro generation in Ethiopia.
Hydro projects	Regulation of inflows: - improved guarantee for irrigation. - opportunity to operate Aswan at lower level for a reduction of evaporation and a conversion to usable supply yield which may more than offset the reduction in power generation. Reduced sediment: extension in life of High Aswam dam

Origin	Disadvantages
Power market	None
Hydro projects	Head loss on Aswan during filling large reservoirs on Blue Nile river: Impact along time to be studied under a variety of conditions (hydrology, sequence of HPP, reservoir sizes, etc) in term of irrigation, capacity (MW), energy (GWh).

9.9.3 Ethiopia

Table 9.15 : Advantages / Disadvantages for Ethiopia

Origin	Advantages
Power market	Valorisation of the hydro power surplus inherent to the Ethiopian power system. Valorisation of the hydro potential of Ethiopia for the benefit of Ethiopia and the interconnected countries. Boost for the development of the Ethiopian power mix, and consequently to the electrification rate in Ethiopia. Securisation of power supply in Ethiopia in case of drought conditions (power import from Egypt and Sudan). Important role for the connection to Kenya and at a latter stage to the SAPP. Increase foreign exchange earnings. Construction employment, new skills for the future.
Hydro projects	Low-cost renewable energy. Regional development (new roads, bridge, development of rural electrification, etc). Poverty reduction. Construction employment, new skills for the future. Development of irrigation.

Origin	Disadvantages
Hydro projects	Capital intensive projects may take time to be finance. Negative ES impacts (but can be mitigated through identified measures)

9.9.4 Sudan

Table 9.16 : Advantages / Disadvantages for Sudan

Origin	Advantages
Power market	Fuel savings. Saved fossil fuel could be exported at a higher price rather than be burned in TPP. Access to the Mediterranean power market, and at a latter stage to the SAPP. Re-enforcement of the complementarily between the Ethiopian hydro system and the Sudanese hydro system (power sales to Ethiopia in drought conditions)
Hydro projects	Regulation of inflows (additional irrigation, navigation, uplift effect at Roseires, Sennar and Merowe: 2 200 GWh/year, equivalent to Dal generation) Reduced sediment: reduction in dredging costs at Roseires, reduction in drainage canal desilting maintenance cost, reduction in pump replacement cost. Development of Irrigation agriculture: two crops per year. Flood reduction.

Origin	Disadvantages
Hydro projects	Reduction in flooding and sediment will lead to the conversion of recession agriculture to irrigation agriculture (but can be mitigated through identified measures).

9.10 CONCLUSION

The present power trade Study is the first quantitative Study analysing the evolution of the three power systems of Egypt, Ethiopian and Sudan up to 2030, and evaluating the benefits that would result from the establishment a regional power market between Egypt, Ethiopia and Sudan.

Previously, the generation expansion plan of Sudan (LTPPS 2006) was studied up to 2030, the Egyptian generation expansion plan covered the period up to 2028, while the Ethiopian expansion plan covered the period up to 2015.

Accordingly, the present Study is the first one giving a quantitative and economic evaluation of the Ethiopian hydropower surpluses available for export up to 2030. This was done on the basis of the data made available to the Consultant and validated by the different Utilities in the course of the present Project.

The Study demonstrates there are significant benefits for the Egypt, Ethiopia, and Sudan to develop an interconnection between their three power systems.

The economic analysis shows that the interconnection will allow to provide Egypt and Sudan with the hydro surplus available from the large Ethiopian HPP projects, and consequently save fossil fuels and reduce CO_2 emissions in Egypt and Sudan.

9.10.1 Ethiopian Hydro Surplus

Ethiopia is well endowed with hydro resources. The hydro potential is estimated at about 30 000 MW, with only a fraction of which has been exploited so far. Accordingly, Ethiopia power systems will be the source of power export to Egypt and Ethiopia.

Part of the Ethiopian hydro surplus available for export are inherent to the internal development of the Ethiopian hydro mix:

- Due to the large size of Ethiopian HPP projects compared to the Ethiopian internal demand (e.g. Mandaya represents more than 1/3 of the Ethiopian demand in 2024), hydro power surpluses are available for export during the first years following the commissioning of these large HPP projects.

- Furthermore, in order to have a proper supply / demand balance all year long and even on the driest years, the Ethiopian hydro power system requires a large amount of installed overcapacity. Resulting hydro surplus can be provided for export when available.

Futhermore, additional hydro surplus could be made available if the commissioning dates of hydro plants are anticipated (with respect to their original schedule when Ethiopia remains isolated).

Finally, the amount hydro surplus will also depends on the growth rate of the Ethiopian demand, the amount of power exported to other countries (e.g. Kenya) and the cost of the Ethiopian hydro projects.

9.10.2 Earliest Date of Commissioning of the Interconnection

It is recommended to time the commissioning of the interconnection in accordance to the earliest commissioning date of the first large Ethiopian HPP project: 2020 (considering time necessary to carry out technical studies, tender process, construction).

9.10.3 Economy of the Interconnection

The present Study shows that the interconnection project is characterized economically by a good profitability, a short payback period and a high benefit to cost ratio.

The economy and optimal capacity of the interconnection were analyzed for two levels of coordination (or two types of power markets) between the three power systems : the loose pool and the tight pool models.

Loose Pool Model

The loose pool model, which consists basically in exporting the hydro surplus inherent to the Ethiopian power system (at no additional cost for Ethiopia), is characterized by:

- no modification of the generation expansion of Egypt and Sudan,

- slight modification of the Ethiopian generation expansion plan (anticipation of Mandaya to 2020),

- some variability of the amount exported power to Egypt (export to Sudan being more base-load) along the period of study,
- lower amount of power export (compared to the tight pool approach),
- but with the advantage of low HPP additional investment cost (the only additional investment cost is the anticipation Mandaya from 2024 to 2020 in time with the commissioning of the interconnection[3]).

Accordingly very good BCR and short payback periods are achieved, the variability of the hydro surplus being balanced by the low global additional generation investment cost.

This model is typical of the actual power exchanges between European countries (spot market, month to month exchanges) which take benefits of temporary (short to medium term) power surplus appearing in one or other country.

In this context, the best scheme, from a strictly economic point of view, would be ET-SUD: 1 200 MW and ET-EG: 700 MW, with a benefit to cost ratio of 4.5 and a very short 3 year-payback period for the reference hypothesis (medium demand projections, medium price projection).

However, going to 2 000 MW capacity to Egypt would still be profitable for the region (benefit to cost ratio =2.3), and would give more freedom and flexibility for a future evolution to a tight pool model, and in a latter stage to an extension of the power market to Kenya and SAPP.

Tight pool model

In the tight pool model adopted in this Study, HPP investments in Ethiopia are anticipated (with respect to their schedule when Ethiopia remains isolated) in order to provide an additional amount of power export. Thus, the power exports arise for one part, from the "natural" hydro surplus inherent to the Ethiopian hydro generation mix, and for the other part from the anticipation of some Ethiopian HPP.

The generation expansion plans of Egypt and Sudan are left unchanged because, due to the projected fuel price increase along the period of the Study, the investment represents only 15 to 25% of the total generation of new thermal plants. Accordingly, the Consultant would not recommend any modification of the Generation Expansion Plans of Egypt and Sudan, which means these countries would still keep their ability to balance their power demand with their own supply whenever power import are available or not.

The tight pool model is characterized by:

- increased amount of exports (compared to loose pool),

[3] For the Ethiopian low demand projection, Mandaya is anticipated from 2025 to 2020, while for the high demand projection no anticipation is required because the "natural" date of commissioning of Mandaya is 2020.

- lower variability of the power export to Egypt along the period of study (compared to loose pool),
- higher generation investment cost in Ethiopia (because of HPP anticipation).

The benefit to cost ratio is lower, and payback period is longer, than in the loose pool model, but these economic indicators remain still very good.

The best scheme, on the basis of the Ethiopian HPP listed in Module 3, and from the benefit to cost ratio criteria, would be ET-SUD: 1 200 MW and ET-EG: 700 MW.

However, the Net Present Value of the scheme with ET-EG: 2 000 MW being very close to the scheme with ET-EG: 700 MW (or even greater for some hypothesis), going to 2 000 MW is certainly preferable, with still a short pay back period of 6 to 7 years according to hypothesis considered.

Preservation of the benefits on adverse evolution of key hypothesis

The interconnection project results in a net profit (benefits greater than costs) even on adverse evolution of key hypothesis (low fuel cost evolution which would reduce fuel savings, or high evolution of Ethiopian demand, which would reduce the amount of hydro surplus).

Potential and actual benefits

The generation savings evaluated in this Module 6 are potential (i.e. theoretical) savings resulting from the optimal coordination of the three generation mixes. The actual savings will depend on the proper development of the power pool, the establishment of short-term and medium term contracts, type of power exchanges (firm, non firm energy), policy to share of cost of investment and the benefit of investment, selling price, wheeling tariff, etc.

Looking into the future

The interconnection between Egypt, Ethiopia and Sudan has a short pay back period (<10 years) for the most relevant projections (high or medium fuel price projections, medium or low demand projections for Ethiopia).

After the payback period (before 2030-2032), the investment cost of the interconnection will be paid, and the remaining cost associated with the transmission of power will be the cost of losses, and to a lesser extend the O&M costs. This will boost the relative economic advantage of hydro power export from Ethiopia, giving opportunity to more hydro investments, for the benefit of the interconnected power systems (lower cost of electricity and reduction of emissions).

Finally, when the perspective is widen to the development of the African power markets, the commissioning of the interconnection between Egypt, Ethiopia and Sudan will be a determining step forward the completion of the connection between the North Africa power markets and the South African power markets (SAPP).

10. FINANCIAL ANALYSIS

10.1 INTRODUCTION

This section describes the Financial Model used in the financial analysis of the project, and for the determination of tariff and IRR requirements and for determining the Royalty and tax payments.

Economic analysis has been carried out separately as part of Module 6 Generation Expansion Plan and is reported separately.

10.2 MODEL STRUCTURE

The financial model used in preparation of this proposal is based on Scott Wilson's model for evaluation of hydroelectric power projects. This model is spreadsheet based, using MS Excel, and comprises three parts:

- Input data
- Financial calculations
- Reporting and financial indicators.

The model has been structured for maximum flexibility in the analysis and evaluation of projects; the input variables can be specified separately and altered easily, enabling alternative scenarios to be analysed quickly.

In order to analyse the Eastern Nile Power Trade Program, which comprises three hydroelectric schemes in Ethiopia and Sudan, the input data has to be specified separately for each of the projects. Hence the model has been developed to provide one common data input sheet and up to five separate project data input sheets. Each project can be selected to be included or excluded from the analysis.

Apart from the five input data sheets (Common Data and separate sheets for each of the schemes), no other data can be input to the model, and the sheets are protected against changes to non-input data cells. In many cells the data is either selectable from a drop-down menu, or is verified to prevent erroneous inputs

10.2.1 Inputs – Common Data

The analysis is carried out in a single selectable currency. The base dates for all costs and tariffs, can be selected independent from the dates of scheme commissioning, and the escalation rates can be specified separately.

Provision in the model is made for:

- Concession Period: this defines the period of commercial operation, which can be selected to start from the commercial operation date of either the first or last project;

- Tariffs – there is provision for one capacity related tariff and four energy related tariffs (typically firm peak, firm off-peak, secondary peak, secondary off-peak);

- Royalty Payments – according to the share of revenue margin formula detailed in Section 7;

- Equity : Debt ratio (specified for the whole project);

- Three types of loan finance (typically ECA, Commercial and development bank), each with separate terms and conditions; the proportion of each loan can be specified separately for each scheme;

- Wheeling charges, based on a capacity charge and an energy charge, with provision for escalation at a specified rate from a nominated base date;

- Carbon Finance revenue, based on CO_2 abated by the energy generated, with the value per tonne specified and with provision for escalation of the value at a specified annual rate from a nominated base date;

- Advance payments, which are independent of any of the individual schemes;

- Working Capital, which is specified in terms of months of revenue;

- Tax and fiscal parameters, including tax rate, exemption period (from the start of commercial operation of the first project) and duty rate (which is set at zero for this study);

- Depreciation life: the normal depreciation life is specified, however in the modelling the life from commercial operation to the end of the concession period is used for each scheme if this is shorter than the normal life.

10.2.2 Inputs – Scheme Data

For each scheme the following data can be specified:

- Date of commercial operation – this is the date on which each scheme is planned to commence operation; it is assumed in the modelling that commercial operation starts at the beginning of the specified year; this year is used as the base year (Year 1) for all calculations relating to the scheme up to the stage when the data from all the schemes is collated;

- Pre-construction costs relating to the individual scheme; this amount is not subject to escalation, and is applied in a specified calendar year;

- Capital costs: the capital costs are specified at base year price levels, and can be separated into civil, E&M, transmission and ancillary works; this separation is used for the depreciation calculations. Separate items are included for Engineering & Project Management and Developer's

Administration costs. Duty, if payable, is applied at the average of the applicable rates to the transmission and E&M equipment;

- Cost scheduling is specified in terms of percentage of capital cost expended in each year prior to commercial operation; this is used for calculation of Interest During Construction;
- Operating costs are specified at base year levels, with provision for general O&M, spares and consumables, insurance and a sinking fund for major overhauls;
- The percentage of the three loans applicable for each scheme can be specified separately, to reflect the difference in characteristics between different types of project (typically more ECA for transmission, less ECA for regulatory dam with no significant M&E plant);
- The capacity and energy outputs for each project must be specified; provision is made for station losses, station consumption and line losses, where these are not covered in the basic scheme data; energy output can be positive or negative; for example a regulatory dam may provide little additional energy, but may increase the firm energy and reduce the secondary energy; the total energy associated with the scheme may be negative if the additional evaporation exceeds the additional flow capture;
- The power and energy generated is reduced by the specified percentage losses to derive the power and energy sales.

10.2.3 Financial Calculations

The financial calculations are carried out on separate sheets for each scheme, to cover the following:

- Financing
- Energy and Tariff Revenue
- Royalty Payments

These parameters are collated and summarised for the whole Project, and in addition summary calculations are performed for the entire project in respect of:

- Capital Cost;
- Operation ad Maintenance Costs
- Carbon Financing
- Wheeling Costs
- Depreciation.

Whereas all the individual scheme analyses are carried out relative to the commercial operating date of the individual scheme, the summaries are collated by calendar year, with Year 1 being six years prior to the start of commercial operation of the first scheme.

The financial calculations carried out are as follows:

- **Financing**: The total scheme capital cost, including escalation and duty but excluding IDC, is divided between equity and debt according to the target ratio. The equity finance is scheduled pari passu with the debt finance, according to the specified capital expenditure schedule. Financing fees are calculated and added to the equity sum, and pre-construction costs are also financed from equity. IDC is calculated up to the second year of commercial operation for each loan, and rolled into the total debt for each loan. It is assumed, although not a pre-requisite of the model, that the loan grace period will cover the duration of debt drawdown, which is typically one year after the start of scheme operation. Repayment of principal (the maximum amount of each loan including IDC) is assumed to be in equal tranches, starting in the year following expiry of the grace period. Interest on the loan is calculated on the basis of the average outstanding sum for the year. The total equity drawdown and total loan drawdown and service for each of the three loans is collated for all five schemes;

- **Energy and Tariff Revenue**: the capacity and energy sales for each year are multiplied by the appropriate escalated tariff rates for the type of energy, and summed to calculate the total tariff revenue each year for each scheme; the totals for all schemes are then collated in a summary;

- **Royalty Payments**: the annual costs for each scheme are calculated according to the formulae in Section 6; the costs are then summed and subtracted from the tariff revenue to derive the revenue margin, and the sharing factor is then applied to determine the Royalty Payments;

- **Capital Expenditure**: the capital expenditure for each scheme included in the analysis is collated for each year, in order to derive the overall capital expenditure profile;

- **O&M Costs**: the escalated O&M Costs for each scheme included in the analysis is collated in order to calculate the overall O&M expenditure;

- **Carbon Financing**: the carbon finance revenue, based on the total energy generated in each year by each scheme included in the analysis, is valued using the escalated value of CO_2;

- **Wheeling Costs**: the costs of wheeling energy through other power systems, if any, is collated and summed for each scheme in the analysis for each year, and then multiplied by the capacity and energy wheeling tariffs;

- **Depreciation**: the annual depreciation allowances for each scheme are calculated for three types of capital cost – civil works, M&E equipment and other expenses / IDC. The annual depreciation allowance is calculated on the basis of the specified normal life, or operating period if this is lesser. All depreciation allowances are then summed for each year for use in the tax calculations.

10.2.4 Output Data

Output data sheets are provided to show:

- **Cashflow Statement**: the overall project cashflow is calculated for each year during the construction and operation periods. The cashflow includes all revenue streams, and all cost streams including capital cost, O&M cost, wheeling, royalties, changes to working capital, debt service and tax. Both pre-tax and post-tax cashflow are presented.

- **Income Statement**: the income statement includes the cost and revenue streams for the project, and in line with standard accounting practice uses depreciation allowances in determining the taxable profit. Corporation tax is calculated, and the post-tax profit determined. In years where adequate cashflow is available the post-tax profit is distributed as dividends, and when there is insufficient cashflow, earnings are retained an distributed when cash is available.

- **Financial Indicators**: a sheet of financial indicators is presented; the key financial indicator is the Internal Rate of Return (IRR) of the equity cashflow (the sum in each year of the equity investment and the dividend/retained earnings), which provides the principal measure of the attractiveness of the project to the equity investors. Other key financial indicators, including NPV of post-tax cashflow and Debt Service Cover Ratio (DSCR) are also presented.

- **Charts**: a series of charts are presented to show annually the components of the Cashflow Statement, the Income Statement and the Royalty and Tax payments (which provide income from the project to the Government).

10.3 PARAMETERS USED IN MODELLING

The parameters used in the modelling are as follows:

10.3.1 Common data

Currency

Currency	USD
Modelling units	$1,000

Base Years for Costs

Base year for capital costs	2005
Base year for O&M Costs	2007
Base year for Tariff	2007
Base year for wheeling charge	2007
Base year for carbon value	2007

Escalation Rates

Escalation for capital costs	2.0%
Escalation for O&M Costs	2.0%
Escalation for Tariff	2.0%
Escalation for wheeling charge	2.0%
Escalation for carbon value	2.0%

Concession

No of Years	30
Start of Concession	COD of last scheme

Tariffs (at base year)

Energy Tariff ($/MWh)	Peak	Average
Firm Energy	Not used	92
Secondary Energy	Not used	92

Carbon Finance (at base year)

CO_2 Abatement (tonnes/MWh)	0.750
Value of ($/tonne)	10.00

Equity Debt Ratio

Equity	25%
Debt	75%

Loan Terms

Loan	Type	Term	Grace Period	Interest Rate	Commitment Fee	Arrangement Fee
1	ECA	12	5	6.0%	0.75%	
2	Commercial	10	5	8.0%	0.75%	1.00%
3	Development Bank	14	5	7.0%	1.00%	

Working Capital

Working capital requirement	3 months

Tax and Duty

Corporation Tax Rate	0%
Exemption Period	Indefinite
Start of exemption period	COD of first project
Rate of Duty	0%

Depreciation (Normal Life)

Civil and infrastructure works	40 years
Mechanical, Electrical and Transmission	20 years
Other costs, including IDC	20 years

10.3.2 Project Data

Data for the three hydroelectric schemes which have been considered as part of the Eastern Nile Power Trade Study are presented in the project data sheets of the financial model and is summarised below:

Power & Energy Generation

Scheme	P3
	Dal
Installed Capacity (MW)	400
Energy generation (GWh/yr) at P1, P2 & P3 as independent projects	Average: 1,944

Project Costs

Scheme	P3
	Dal **USD Millions**
Capital Cost-escalated ($m)	1,113.2
IDC ($m)	233.0
Cost incl. IDC & fees ($m)	1,586.8
Annual O&M cost ($m)	5.6

Loan Percentages

Scheme	P3
	Dal
Loan 1 percentage	30%
Loan 2 percentage	40%
Loan 3 percentage	30%

10.4 RESULTS OF MODELLING

The Financial Model has been run with a range of scenarios in order to establish the financial viability of the project. The objective of the financial modelling has been to derive the ex-power station energy price that will provide a 20% post tax internal rate of return. As the projects are regional projects it has been assumed that they would be exempt from National taxation in the host country, hence the pre-tax and post-tax rates of return would be similar.

For the Dal project the energy tariff required to provide the selected rate of return was found to be USD 92 / MWh. The conclusions of the modelling are presented below. Details are provided in Appendix 9.1.

10.4.1 Transmission Line

The transmission interconnections and associated wheeling charges have not been included in the analysis as these are reported separately in the report for Modules 6 and 7 of the Program Study.

10.4.2 Carbon Finance

In order to achieve acceptable financial performance the revenue from sale of emission reduction units under the Clean Development Mechanism (CDM) of Kyoto has been included in the Base Case financial model.

10.4.3 Financial Indicators

The key financial indicators derived from the Base Case financial model are as follows:

Year of Operation	Calendar Year	Post-tax Internal Rate of Return	NPV of Post-tax Cashflow USD Millions
5	2020	0.0%	-$52.7m
10	2025	14.0%	$47.5m
15	2030	18.0%	$143.9m
20	2035	19.3%	$218.9m
25	2040	19.9%	$281.2m
30	2045	20.1%	$324.2m
Minimum Debt Service Cover Ratio			1.14

Notes:

1. Post-tax IRR is the Internal Rate of Return (Equalising Discount Rate) of the post-tax equity cashflow, which comprises equity drawdown, dividend and retained earnings;

2. NPV of post-tax cashflow is discounted at 10% to year 1 of the financial model;

3. Minimum DSCR is the ratio of Operating Cashflow (all revenue less all operating costs) to the sum of the interest and principal repayments. Typically this ratio is required by financiers to be a minimum of 1.4.

11. DAL HYDROPOWER PROJECT – CO_2 EMISSION

11.1 INTRODUCTION

The proposed Dal hydropower project on the River Nile in Sudan offers potential for generating energy to support regional economic growth. In the following sections the CO_2 emissions resulting from the project's construction activities and the decomposition of biomass in the project reservoir are quantified and compared with the potential CO_2 emissions from generating the same electrical energy through burning fossil fuels.

11.2 CO_2 EMISSION BY THE DAL HYDROPOWER PROJECT

The CO_2 emission associated with a hydroelectric power project are those produced during the manufacture and construction of the project structures and equipment and those produced by slowly decomposing biomass in the reservoir during the project's lifetime.

11.2.1 CO_2 Emission related to Construction

It is well known that the implementation of a hydroelectric power plant involves considerable construction activities and large quantities of construction materials which, in turn, require a large energy input. For the construction of the Dal project the required quantities of major construction materials and consumables are summarized in Table 11.1.

Table 11.1 : Quantities of Major Construction Materials and Consumables

MATERIALS / CONSTRUCTION	QUANTITIES
Civil Works	
- Soil excavation	4,638,000m^3
- Rock excavation	4,308,000m^3
- Conventional concrete	522,600 m^3
- Reinforcement steel	42,400 tons
- Diesel fuel	23,000 tons
Electro-mechanical equipment	
- Steel	7,500 tons

Based on the volume of concrete and other construction activities such as grouting, shotcreting, etc. a cement requirement of about 183,000 tons is calculated. The production of one ton of cement requires approximately 4 GJ of energy. Hence the energy input for all concrete works results in approximately 732,000 GJ.

The weight of reinforcement steel, hydraulic steel structures and steel for the electro-mechanical equipment totals about 50,000 tons. It takes approximately 40 GJ of energy to produce one ton of steel. Therefore, the energy input into steel and equipment is about 2 million GJ.

The energy requirement for the excavation, transport and placing of soil and rock material is covered under the diesel fuel requirements of 23,000 tons.

If it is assumed that the energy required to produce the cement and steel is generated by a thermal mix as described below (coal/gas = 50/50 per cent) then some 47,000 tons of coal and 31,000 tons of gas would be needed. The burning of these fossil fuels would ultimately lead to a CO_2 emission of approximately 215,000 tons.

The burning of 23,000 tons diesel fuel will result in a CO_2 emission of about 74,000 tons. The total emission of CO_2 associated with the construction of the Dal hydropower project will thus be approximately 290,000 tons.

11.2.2 CO_2 Emission caused by the Biomass with the future reservoir

The Dal hydropower project will inundate a gross area of about 300 km^2, which, after exclusion of the existing river channel, will result in a net area of about 250 km^2 of land. The biomass is limited to the immediate area of the river banks as the remaining area is desert and a total biomass of about 35,000 tons (dry weight) is estimated.

All living plants grow by absorbing water and carbon dioxide to form reserves of carbohydrate, known as biomass. This process is fuelled by sunlight and is termed photosynthesis. In simple terms the process is as follows:

$$6\ CO_2 + 6\ H_2O \rightarrow C_6H_{12}O_6 + 6\ O_2\uparrow$$

When plants die, decomposition by oxidation takes places which is the photosynthesis process in reverse:

$$C_6H_{12}O_6 + 6\ O_2 \rightarrow 6\ CO_2 + 6\ H_2O$$

The same amount of CO_2 absorbed during photosynthesis is released during complete oxidation of the biomass.

By considering molar weights, one ton of carbohydrate produces 1.47 tons of carbon dioxide during complete decomposition as follows:

$$180\ g\ C_6H_{12}O_6 + 192\ g\ O_2 = 264\ g\ CO_2 \uparrow + 108\ g\ H_2O$$

$$1\ t\ C_6H_{12}O_6 + 1.07\ t\ O_2 = 1.47\ CO_2 \uparrow + 0.6\ H_2O$$

Using the same relationship on the total estimated quantity of biomass affected by the Dal hydropower project the decomposition of the biomass in the reservoir area could lead to a maximum CO_2 emission of about 52,000 tons.

11.2.3 The Total CO_2 Emission of the Dal Hydropower Project

Approximately 290,000 tons of CO_2 will be produced with the construction of the Dal hydropower project. The maximum potential CO_2 emission associated with the aerobic decomposition of the biomass located in the reservoir is estimated to be approximately 52,000 tons. Thus the implementation of Dal hydropower project will lead to a total CO_2 emission of about 342,000 tons.

11.3 CO_2 EMISSION BY EQUIVALENT THERMAL POWERPLANTS

This section quantifies the CO_2 emissions resulting from generating the same average energy as Dal but by burning fossil fuels. Present thermal plant technology does not include the recovery of carbon dioxide from flue gases. Hence the carbon content of the fuel and the efficiency characteristics of the thermal plant are the governing parameters in calculating CO_2 emission levels. The following formula may be used to compute the CO_2 emission from fossil fuels:

$CO_2 = A \times (B + C \times HV)$

where:

CO_2 = emission of CO_2 in metric tons per ton of fuel;

A = multiplier for indirect emissions (exploration, mining);

B, C = regression constants for the particular type of fuel;

HV = lower calorific value of fuel in GJ/ton.

Typical CO_2 emissions for various type of fossil fuel are shown in Table 11.2. Approximate CO_2 values per MWh delivered to the grid would be as shown in Table 11.3 for various types of powerplant.

Table 11.2 : Typical CO_2 Emissions for various Type of Fuel

Fuel Type	A	B	C	HV (GJ/ton fuel)	CO_2 (ton/ton fuel)
Lignite	1.08	0.20090	0.08693	7	0.87
Coal	1.06	0.20090	0.08693	29	2.90
Oil	1.04	2.50291	0.01494	41	3.24
Gas	1.01	0.55159	0.04463	44	2.53

Table 11.3 : Approximate CO_2 Emission per MWh for various Types of Thermal Powerplants

Plant Type	HV (GJ/ton fuel)	CO_2 (tons/ton fuel)	Efficiency (per cent)	CO_2 (ton/MWh)
Lignite-fired steam	7	0.87	36	1.24
Coal-fired steam	29	2.90	37 - 39	0.97
Oil-fired steam	41	3.24	38 - 40	0.75
Gas-fired combined cycle	44	2.53	48 - 52	0.43

Note:Efficiencies shown include station consumption.

The annual average energy to be generated by the Dal hydropower project would amount to 1,944 GWh/yr. If the same quantity of energy was to be generated by a thermal mix consisting of 50 per cent coal-fired and 50 per cent gas-fired combined cycle power plants, some 1.36 million tons of CO_2 would be discharged to the atmosphere annually.

Table 11.4 : Approximate CO_2 Emission of equivalent Thermal Power Mix

Plant Type	Annual Energy GWh	CO_2 Million tons
Coal-fired steam	972	0.94
Gas-fired combined cycle	972	0.42
Total	**1,944**	**1.36**

It is noted that the CO_2 emission of 1.36 million tons annually is related purely to the fuel consumption (equal proportions of coal and gas) and does not include the CO_2 emission related to the construction of the thermal power plants.

Assuming that the annual average energy generated by the Dal hydropower project would be generated by an "environmentally friendly" gas-fired combined cycle power plant only, which is a most optimistic scenario, then the annual CO_2 emission into the atmosphere would be approximately 0.8 million tons.

11.4 CONCLUSION

The energy sector is the greatest single source of CO_2 emissions into the atmosphere and within that sector the burning of fossil fuels to generate electricity accounts for some 25 per cent of global warming. The Dal hydropower project will produce an average of 1,944 GWh of electrical energy annually. During construction of the project, energy is required to manufacture cement and steel and to excavate and construct the project structures. The generation of this energy will result in the release of CO_2 into the atmosphere. During operation of the project, the residual biomass submerged within the reservoir will slowly decompose also releasing CO_2 into the atmosphere. The estimate of the total quantity of CO_2 released into the atmosphere during construction and operation of Dal will be some 342,000 tons.

Generating the same energy by burning fossil fuels (equal proportions of lignite, coal, oil and gas) would release into the atmosphere some 1.36 million tons of CO_2 every year. Over a period of 50 years, the assumed commercial life of Dal, this annual CO_2 emission would result in a total of 68 million tons of CO_2. Consequently the generation of hydro-electric energy at Dal will result in CO_2 emissions 200 times less than if the same energy were generated by burning fossil fuels.

12. CONCLUSIONS AND RECOMMENDATIONS

12.1 CONCLUSIONS AND RECOMMENDATIONS

12.1.1 Conclusions

It is concluded from the studies described in the earlier Chapters that the Dal hydropower project offers an opportunity for energy generation to meet some of the future energy demands within the Eastern Nile region. A 400 MW development at Dal will provide an average energy output of 2,160 GWh/yr.

In addition to the energy output the Dal project would provide savings in CO_2 emissions associated with alternative thermal generation options of some 68 million tonnes over 50 years.

As with any major hydropower development, there will be negative impacts associated with development of the Dal project. The population within the proposed Dal reservoir area is significant (approx. 40,000 persons). A detailed programme for resettlement will be required including appropriate planning and compensation arrangements.

The Dal reach of the Nile is host to extensive historical remains of archaeological importance. Planning of development of the Dal project will need to take account of research costs to investigate remains and to relocate structures where appropriate.

12.1.2 Recommendations

It is recommended that feasibility studies are carried out of the Dal project at the earliest opportunity. Extensive studies will be required in the vicinity of the Dal site in Sudan, in the affected zones along the Main Nile upstream and downstream to assess the impacts on population and cultural property.

Particular attention will be required to a number of topics including:

Topographic Survey

A high accuracy GPS ground control system needs to be established at the Dal site. This should include a network of not less than 6 permanent primary reference stations on both banks of the river and including reference stations at or close to river level as well as on the nearby hills on both banks.

Maps of the project site should be prepared at a scale of 1:1000 with 0.5 m contour interval. The mapping shall cover an area of at least 2 km upstream and 3 km downstream of the dam centreline and shall extend from the river edge on each bank to an elevation of at least El. 220m.

Hydrographic Survey

Hydrographic surveys will be required at cross-sections of the Nile river. These should be carried at intervals of 1000 metres for 20km upstream and 10 km downstream of the dam centreline.

Hydrology

It is recommended that the a hydrometric gauging station is established at the Dal site and provided with a staff gauge and that a series of flow measurements is carried out by current meter over a wide range of flows

Geological and Geotechnical Investigations

It will be necessary to carry out a major programme of geological and geotechnical investigations of the Dal site and the proposed construction materials. It is anticipated that the programme will include some 1500 metres of core drilling (20 holes) with associated insitu and laboratory testing.

Environmental and Social Impact Assessment

It is recommended that a detailed ESIA is carried out including preparation of a resettlement action plan. This is described in more detail in the ESIA Report.

12.2 TERMS OF REFERENCE FOR TECHNICAL FEASIBILITY STUDIES

Contracts have recently been awarded by the Government of Sudan Dam Implementation Unit (DIU) for the feasibility studies of the Dal hydropower project. Terms of reference for these studies have been prepared by DIU.