FINAL REPORT: NOVEMBER 1999

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Senegal Independent Power Plant Feasibility Study

prepared for

Société Nationale d'Electricité

and

U.S. Trade and Development Agency
TDA Project No. 96-004A

prepared by:
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ACKNOWLEDGEMENTS

The work represented herein is sponsored by the U.S. Trade and Development Agency and prepared by a team under the direction of Parsons Energy & Chemicals Group in Reading, PA. Following are the project participants who made significant contributions:

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Further, the basis for this work reflects technical and financial inputs provided by Senegal counterparts. The responsibility for the validity of these inputs remains with them. While an attempt has been made to reconcile all inputs, the product of this work is commensurate with conceptual level of work detail. The authors do not take direct responsibility for decisions which are based on the conceptual results presented in this study.

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TERMINOLOGY USED IN THIS REPORT

bcf	billion cubic feet (35.31 bcf = 1 bm^3)
billion	10^9
Btu	British thermal unit
°C	degrees Celsius
CC	combined cycle
CEM	continuous emission monitor
CO	carbon monoxide
COFACE	Compagnie Francaise d'Assurance pour le Commerce Exterieur (French trade finance agency)
CT	combustion turbine
CTG	combustion turbine generator
DEG	German Investment and Development Company
DSCR	Debt Service Coverage Ratio
ECA	Export Credit Agency
EENS	expected energy not served
ELFIN	an electric utility financial and production cost model
EMSI	Enterprise Multi-Services Internationale (an in-country engineering firm)
EPC	engineer, procure and construct
°F	degrees Fahrenheit
GT	gas turbine
GTCC	gas turbine combined cycle
h, hr	hour
HLOLE	hourly loss of load expectation
HP	high pressure
HRSG	heat recovery steam generator
IBRD	International Bank for Reconstruction and Development (The World Bank)
IFC	International Finance Corporation (arm of the World Bank)
IMF	International Monetary Fund
IP	intermediate pressure
IPP	independent power plant
IRR	internal rate of return
ISO	International Standards Organization
kg	kilogram (1 kg = 2.2046 lb)
kJ	kilojoule
kV	kilovolt
kW	kilowatt
LHV	lower heating value
PC	pulverized coal
LOLE	loss of load expectation
MARAD	US Department of Transportation, Maritime Administration
mg/m^3	milligram per cubic meter
million	10^6
min	minute
MJ	megajoules, (10^6 joules)
mm	millimeters
MMBtu	Million British thermal unit
MOF	Ministry of Finance
MPa	megapascal
MWe	megawatt, (1000 kWh), electric
MWh	megawatt-hour, (1000 kWh)
MWt	megawatt, (1000 kWh), thermal
NA	not applicable, not available
Nm^3	normal cubic meters, (0°C, 1 atm)
NOx	nitric oxides
NPV	net present value
O_2	oxygen
O&M	operations and maintenance
OECD	Organization for Economic Cooperation and Development
OPIC	Overseas Private Investment Corporation

Part.	particulate emissions
PC	pulverized coal
PPA	Power Purchase Agreement
PPG	Parsons Power Group, (Now Parsons Energy & Chemicals Group)
Q	heat
SACE	Sezione Speciale per l'Assicurazione del Credito all'Esportazione (Italian trade finance agency)
SCR	selective catalytic reduction (for NOx control)
s, sec	second (time)
SO_2	sulfur dioxide
ST	steam turbine
T&D	transmission and distribution (electrical)
t	tonne, metric (1000 kg, 2,205 lbs)
Tcal	teracalorie (10^{12} calories)
TG	turbo-generator, (turbine-generator)
t/h	tonne/hour
TJ	terajoules, (10^{12} joules)
ton	ton, (2000 lbs)
tonne	metric ton, (1000 kg, 2,205 lbs)
US, U.S.	United States
USD, US$	the United States Dollar
USTDA	United States Trade and Development Agency
VAT	value added tax
WB	World Bank (IBRD)
y, yr	year

EXECUTIVE SUMMARY

This report presents the results of the Senegal Independent Power Plant Feasibility Study funded by the U.S. Trade & Development Agency (USTDA) under a grant to SENELEC. The primary study objective is the preparation of appropriate technical and financial analyses that will support SENELEC's development of an Independent Power Plant as the next addition to their generating fleet. The following sections summarize the completed work, and also present the Parsons Team conclusions and recommendations.

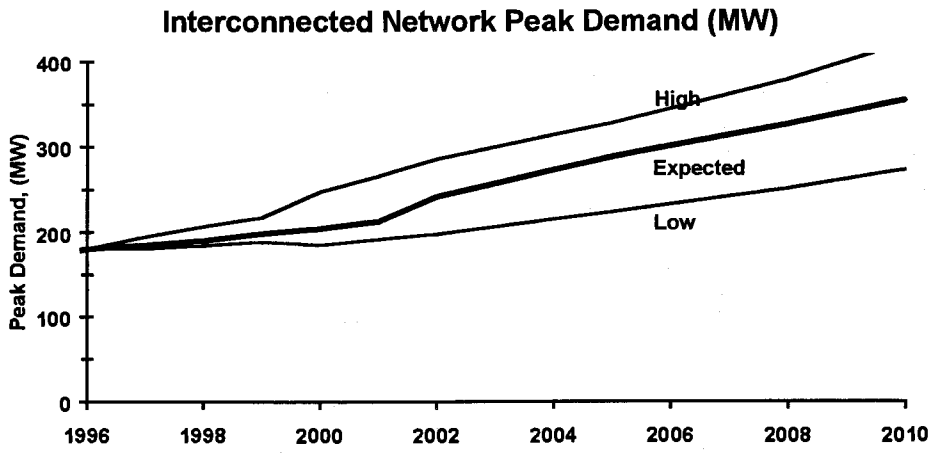
Demand Growth: Basis for New Generation Capacity

SENELEC has a significant need for new electric generation. They experience routine power outages that reduce productive work, impact the social fabric, and stifle economic growth. It is expected that within the next 10 years, SENELEC will retire over 120 MW, or approximately 45% of their presently installed capacity. Many of these units have poor efficiencies; burn high sulfur, heavy oil; and are in poor condition.

The Senegal population is estimated to grow at a rate of 2.6%/year between 1988 and 2010. Meanwhile the country-wide household electrification rate has increased from 20.3% in 1988 to 26% in 1995, and is expected to continue to rise.

As a result, electric demand is expected to grow 5.2%/year between 1997 and 2010. This projection has been made by SENELEC based upon the PVS computer model that simulates growth in the domestic and industrial sectors, while recognizing the impact of new industrial projects. The projected demands are dependent on SENELEC's ability to provide affordable and reliable electric power to attract industry and maintain consumer confidence.

The SENELEC demand forecast appears well substantiated, and serves as a basis for the IPP capacity addition. The peak demand including transmission and distribution losses is presented below.



Fuel: The Largest Operating Cost

Senegal has very limited indigenous energy resources, necessitating the import of large quantities of petroleum products.

In 1997, the Senegalese Government announced the discovery of a significant natural gas reserve of approximately 10 billion m^3; (200 MWe GTCC for approximately 30 years). PETROSEN's (Société des Pétroles du Sénégal) preliminary interpretation of test data indicated a proven reserve of only 0.6 billion m^3 (20 bcf), but they are hopeful of finding larger reserves. During 1998, the primary existing well was closed, and a new well opened with 5MMft^3/day capacity. The reserves are small, however, due to a "compartmented" configuration of the gas cavern. Gas exploration by PETROSEN and Tullow Oil continues; however, the expectations of finding significant gas quantities are lower than even one year ago.

Other indigenous fuels to Senegal include peat, and some uneconomic offshore oil, but none are considered viable fuels at this time. Coal plants were also considered, but were also found to be uneconomical.

Other than natural gas, the only other viable fuels for the IPP are imported liquid fuels, historically a primary fuel for SENELEC. Unfortunately, refined liquid fuels are expensive, and the more affordable heavy fuel oil is environmentally unattractive.

Considering the current state of gas development in Senegal, the IPP feasibility study proceeded on the assumption that natural gas will be available, but an alternate barge-mounted oil-fired plant was developed. Natural gas condensate is considered a cost competitive potential fuels for a barge-mounted plant, or even the land-based plant at Kayar.

Generation Expansion Planning: Selecting the Plant Configuration

To examine SENELEC's need for a new sources of power, Parsons has independently developed a generation planning model and performed resource optimization using the ELFIN computer code (Section 4).

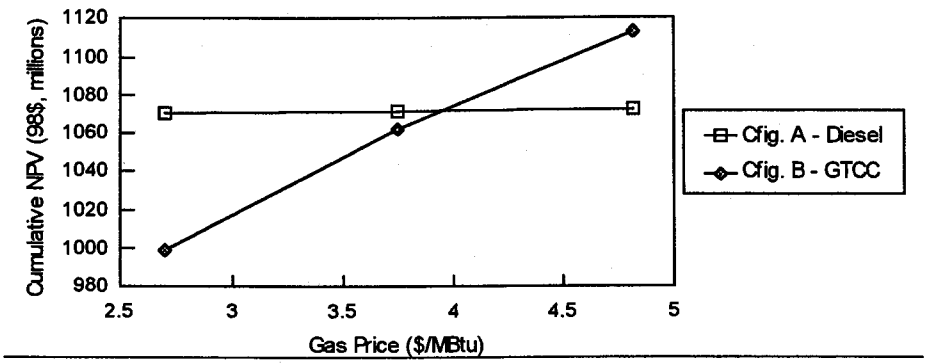
The ELFIN program performs maintenance scheduling, commitment, and a detailed economic dispatch of the modeled units and is capable of determining fuel costs, shortage costs, fixed and variable O&M costs, capital costs, marginal energy costs, loss of load probabilities, energy not served, reserve, emissions, and perform resource planning optimization among other things. Optimization algorithms also determine the optimum mix of existing and new resources that will serve the system demand at the lowest possible total cost.

Options considered for potential generation expansion:

- 20 MW Gas Turbine (gas or diesel fuel)
- 60 and 90 MW GTCC (gas or diesel fuel)
- 5 MW Diesel (diesel fuel)
- 20, 60, or 90 MW Diesel (heavy oil fuel)
- 60 or 90 MW oil fired steam (heavy oil fuel)
- 90 MW coal-fired steam

Resource optimizations were performed for natural gas prices of US$4.81 and US$2.70/MMBtu. High gas prices favor the heavy oil burning diesels. Low gas prices favor the gas-fired gas turbine combined cycles.

A sensitivity on natural gas price demonstrated that gas prices above approximately $3.95/MMBtu support the diesel technology; below this price, gas turbines are favored, as shown below. Further, the current gas price of $4.81/MMBtu would not support an investment in a large gas-fired GTCC plant.



Option Selection Consideration is given to both the generation planning results as well as the electric stability analysis (Section 6). The electric stability analysis indicates that a 60 MW unit is stable but that a 90 MW unit is not, and the trends suggest that the unit size be limited to about 75 MW.

The resource optimization process identified specific capacity additions of 60 MW in 2001. Environmental characteristics also favor the gas turbine option burning gas over the diesel option burning high sulfur fuel oil. Therefore, we recommend the addition of a 60-75 MW size GTCC for operation in the year 2001.

Gas Turbine Model Screening Three Frame turbines were selected for review. Major combined cycle equipment was designed, costs estimated, and part load performance developed for Senegal conditions, as shown below:

Manufacturer		Westinghouse	ABB	Siemens
Model		251B11	GT8C	V64.3
Combined Cycle Cost Data				
Capital Cost	$, 10^6	57.8	62.7	68.8
Capital Cost	$/kW	887	918	860
100% Load Point- GTCC				
Net Power, new	MWe	65.2	68.3	80.0
Net Efficiency, new	%	45.6	47.4	48.2
Net Power, degraded 3%	MWe	63.2	66.2	77.6
Net Efficiency, degraded 2%	%	44.8	46.5	47.2
Annual Fuel Consumption				
Fuel Usage @ 80% CF	10^6 m^3/yr	109	110	126

Notes: 1. The combined cycle information has been developed by Parsons on the basis of: 25°C (77°F), 60% relative humidity, 60 m elevation, dual pressure non-reheat steam turbine, steam temperature of 850 psig, steam temperature set to gas turbine exhaust minus 50°F, a wet dry cooling tower, condenser back pressure of 1.5 psia, high pressure, and no air pre-cooling.

Based upon a preliminary electric stability analysis, the larger size of the Siemens V64.3 could create a system stability problem. Comparing the W251 and the GT8C machines, the GT8C is slightly larger, more efficient, and with a slightly higher specific cost.

Both of these units have significant potential to be effectively utilized in the SENELEC system expansion plan. ABB now offers an upgraded version on the GT8C, the GT8C2, with a slightly higher capacity. The conceptual design effort focused on the ABB GT8C; however, in the bidding stage, the GT8C2, and even the Seimens V64.3, can be reconsidered based on the status of the SENELEC system at that time.

Electric System Studies: Basis for Unit Size and System Location

To develop the Load Flow Analysis, four different generation dispatches were studied, both with the 90 kV bus tie of the Cap des Biches station open and closed. The studies were made with the new 60 MW combined cycle units installed at Tobene and alternately at a new site at Kayar, for a total of 16 different runs. In developing the Kayar generating site, it has been assumed that the 90 kV line between Cap des Biches and Tobene, which is constructed for 225 kV operation, is looped in and out of the Kayar bus.

The Transient Stability Analysis determines the size of the generating unit that the SENELEC interconnected system is able to support. Specifically, this analysis addresses the question: What is the proper size of the installed combined cycle plant that can provide needed capacity to meet system loads until the Manantali hydro is available? Two unit sizes were investigated: 60 MW net and 90 MW net.

The studies were carried out by means of a transient stability analysis of the conditions obtained upon the loss of the most loaded unit (i.e. combined cycle unit). The ability of the system to sustain the loss of a major unit and still maintain proper frequency and voltage, is dependent, in large measure, upon the amount of available unused capacity, or "spinning reserve" in the units that are on-line. Insufficient spinning reserve will result in undesirable load shedding.

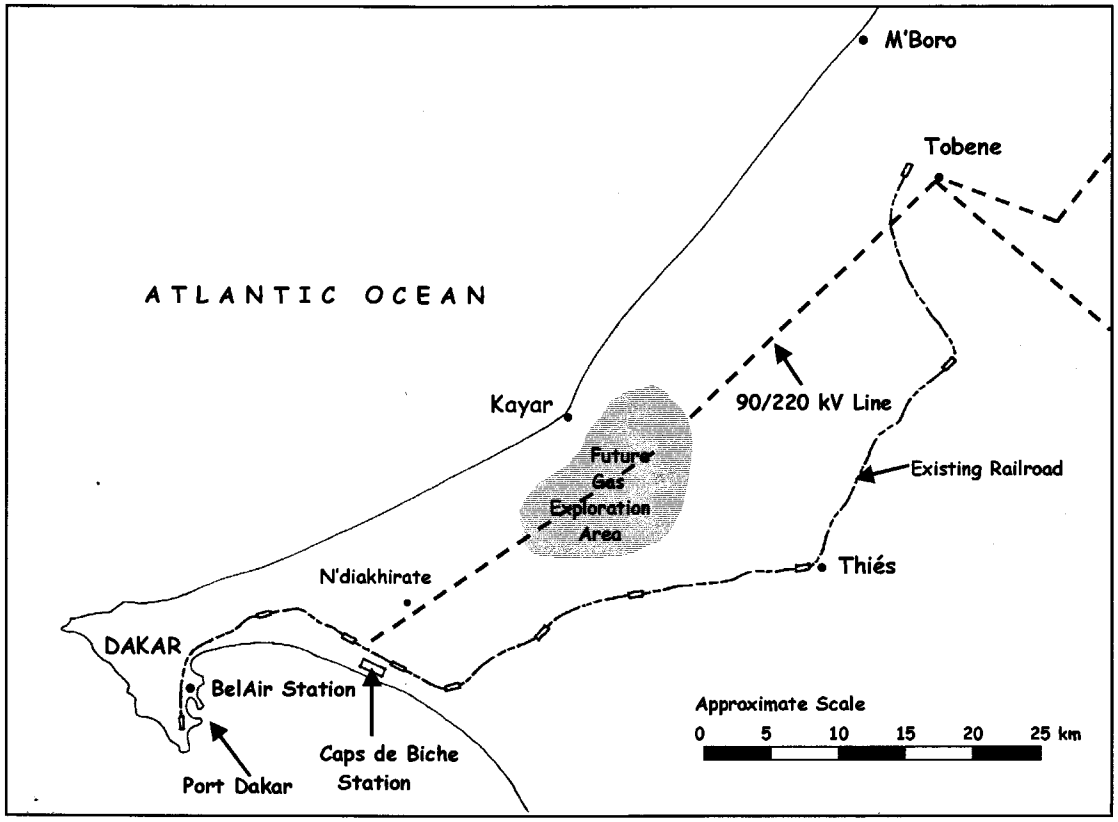
The electric system studies demonstrate that the installation of the 90 MW unit will result in load shedding, while the smaller unit will not. For this reason, and the higher reliability obtained with the smaller 60 MW unit, the 60 MW class unit is recommended over the 90 MW class unit. The indicated trends suggest that a generation unit (for the project) of up to 75 MWe is likely to be acceptable.

The analyses also support the generating site development at either Kayar or Tobene, and that the system can operate equally well with the Cap des Biches bus tie open or closed provided that the generating units of Cap des Biches are properly balanced on the two busses.

Site Evaluation: Basis for Physical Plant Location

N'diakhirate, Tobene, and M'boro sur mer (on the sea) sites were originally considered by SENELEC. Two additional sites, BelAir and Kayar, were added during the study. The approximate location of these sites, together with proximity of existing/future natural gas supplies, high voltage lines, and railways is presented below.

Location of Sites Considered for the Gas-Fired IPP



The following exhibit presents the results of a qualitative assessment conducted by the Parsons Team, and supported through conversations with the SENELEC staff:

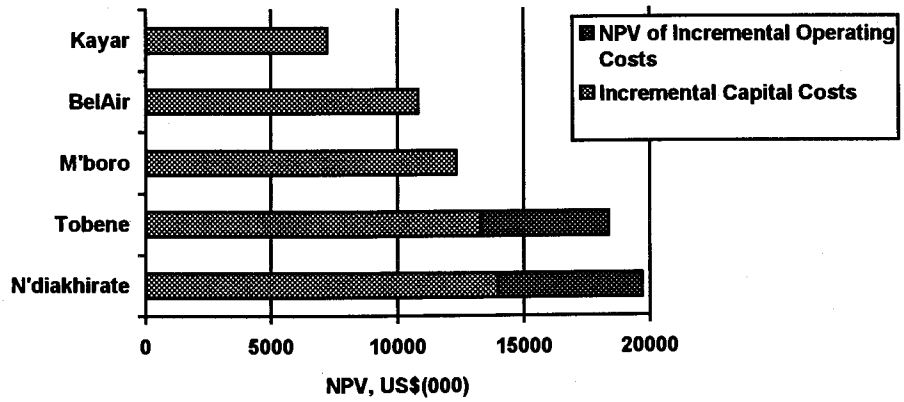
Evaluation Parameter	N'diak-hirate	Tobene	M'boro	BelAir	Kayar
Desired location for economic growth	3	3	4	1	4
Generation diversity	4	4	4	2	4
Environmental Impact	3	4	4	3	4
Existing design data	2	3	2	4	3
Proximity to population areas	4	4	4	1	3
Possibility of future expansion	4	4	4	2	4
Site development risk (substructure)	3	4	4	4	3
Site development cost risk (water)	3	3	4	4	4
Site development cost risk (gas)	4	3	3	2	4
Impact on electric grid stability	2	3	3	4	3
Total Score[a]	2.91	3.18	3.27	2.45	3.27

Note: a. Range of scores is 1 to 5, with 5 being the best score.

As possible, the following aspects of cost and performance were quantified, considering that the plant would eventually consist of two units totaling more than 140 MWe:

- Site development differences
- Plant design and performance differences,
- Off-site development, and
- Operating cost differences.

The screening results are presented below (lower NPV is better).



The Kayar site is preferred over the second choice, BelAir. By locating the plant near the sea, and close to existing and future gas development, the Kayar site has the best chance of achieving the lowest cost.

A conceptual design and capital requirements of the IPP plant at Kayar were developed and utilized as a basis for financial analysis (Section 8).

Financial Analysis and Structure: Basis for Financing

A previously financed IPP sets a strong precedent and allows Senegal/SENELEC to consider shifting the financial burden of a new plant away from the public sector. The privatization of a majority of SENELEC's shares will bring an international partner who may wish to assume the additional financial burden of the IPP. However, the intent in the current privatization is for SENELEC to evolve as a distribution company, limiting its generation ownership to currently owned plants.

Regarding limited recourse financing, SENELEC has already expended considerable effort to successfully implement an IPP project on a limited recourse basis. Assuming that this experience can be applied to the new IPP project, the limited recourse option is attractive.

Sources of Financing

Each potential source of financing has its own lending requirements. Four general sources, represented by types of institutions, include:

- **Commercial Banks** International commercial banks' participation would be limited to co-financing arrangements with multilateral agencies due to the requirement for political risk and commercial risk guarantees from "Official" sources of financing, i.e. export credit agencies or multilaterals. Consequently, the financing structure for SENELEC begins with "Official" lenders requirements.
- **Export Credit Agencies** Export Credit Agencies (including U.S. Ex-Im Bank, ECGD, Japan Ex-Im Bank, Hermes, SACE, and COFACE) are potential sources of long-term debt financing with more generous terms than those of commercial banks. The Federal Ship Financing Program, US Department of Transportation - Maritime Administration ("MARAD"), is suitable for SENELEC if the new project became a power barge.
- **Multilateral / Bilateral Institutions** The multilateral/bilateral institutions with greatest interest include the International Finance Corporation (IFC) - the private sector arm of the World Bank -, the German Investment and Development Company (DEG), the British Commonwealth Development Corporation, and the US Overseas Private Investment Corporation (OPIC).
- **Local Banks** The participation by local banks will be required primarily for working capital purposes.

Proposed Financing Plans

Total Project Costs for the plant are estimated to be $ 74.4 million. Over 80% of the financed amount is eligible for Export Credit Agency funding. We expect that the lenders will require a debt to equity ratio of 70:30. Sources of equity will be the IPP developer with possibly some related project parties. Additional sources may be certain African private equity investment funds (such as New Africa Opportunity Fund).

Two potential financing plans are considered:

1. **Export Credit Agency Lead** An ECA can limit the number of lenders for a project to one, thus simplifying the financing process. The project developer must ensure that: (a) Virtually all equipment, engineering, and services are procured from one country; (b) The ECA is "open" for Senegal, and this ECA provides comfort to the liquidity providers under political and commercial risk covers; and (c) The local cost component is limited to approximately 15-20%.

   Assuming that much of the procurement will be sourced in the United States, US Ex-Im Bank will be a suitable lender. Exim is

capable of doing long tenors for limited recourse transactions and has successfully financed IPPs around the world. We assumed a 12 year repayment term for Senegal, in particular considering SACE's tenor in the GE Capital project. A proven developer and a solid EPC contractor with influence on the ECA will considerably enhance the chances of securing attractive financing terms.

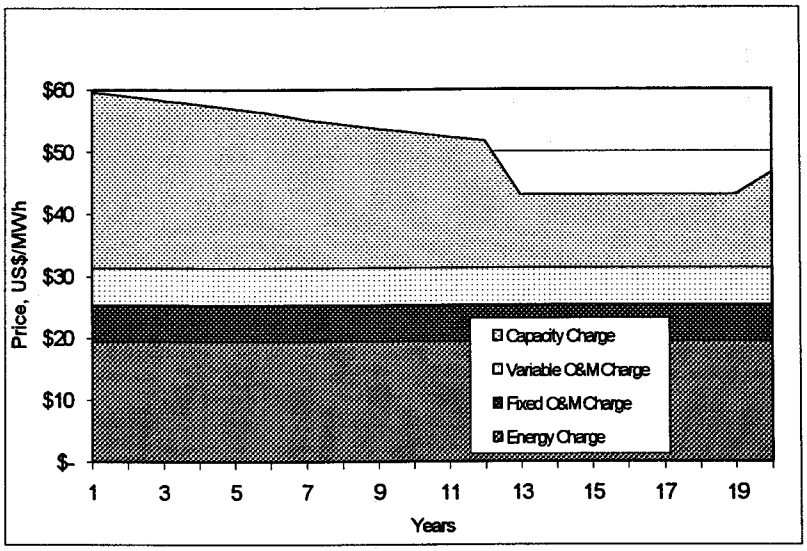
2. **Multilateral and ECA Combination** The primary reason for a combination would be greater flexibility of equipment procurement. A multilateral provides untied financing to the sponsors, yet forces international competitive bidding (ICB) for their portion of costs, unless the project itself was won on an ICB basis.

   As a first component, the multilateral (or bilateral in OPIC's case) would provide up to 50% of the project costs, with the balance being secured from an ECA. OPIC would be available to the extent the project has a US sponsor with 25% ownership. The two lender option will increase the financing process costs and incur a longer processing time, with the additional complexity of their respective legal and commercial issues to be addressed.

Analysis and Results

The financial model considers Financing Plan 1 (ECA led). The model targets a minimum debt coverage ratio (DCR) of 1.3 times and a minimum Internal Rate of Return (IRR) to the equity of 23%.

The tariff was derived using a traditional two-tiered tariff structure (Capacity Charge and Energy Charge), and a slightly declining equity return component over the 20 year period, beginning at US$ 8,500 per kW per month. The 20 year average tariff is US$ 50.77/MWh, with the following tariff profile through the project life:



An IRR of 23.0% is achieved, with a minimum DCR of 1.38. The new IPP has economic viability at reasonable (unescalated) tariffs. A well run competition may result in lower tariffs driven by lower project costs and/or a lower return on equity target.

The Barge-Mounted Plant: The Flexible Option

Since natural gas development in Senegal is uncertain at this time, a barge-mounted plant of equivalent capacity was developed as an alternative to the Kayar land-based plant. Barge-mounted gas turbine plants are seeing increasing application around the world. Senegal is a very appropriate location for a barge-mounted plant application for the following reasons:

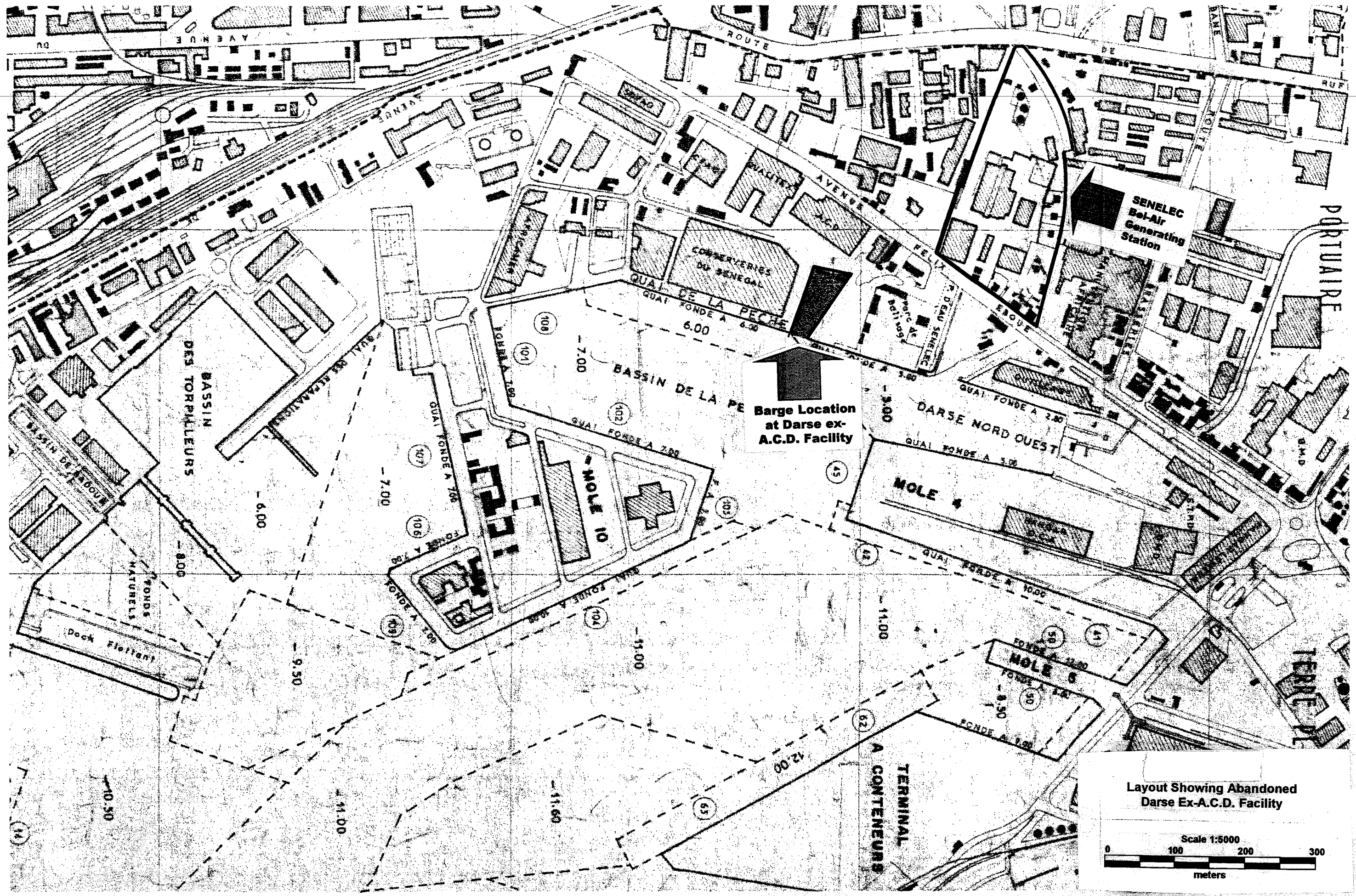
- Competitive capital cost,
- Potential short implementation schedule,
- Likelihood of improved financing terms, and
- Plant can be relocated to take advantage of a future natural gas supply location.

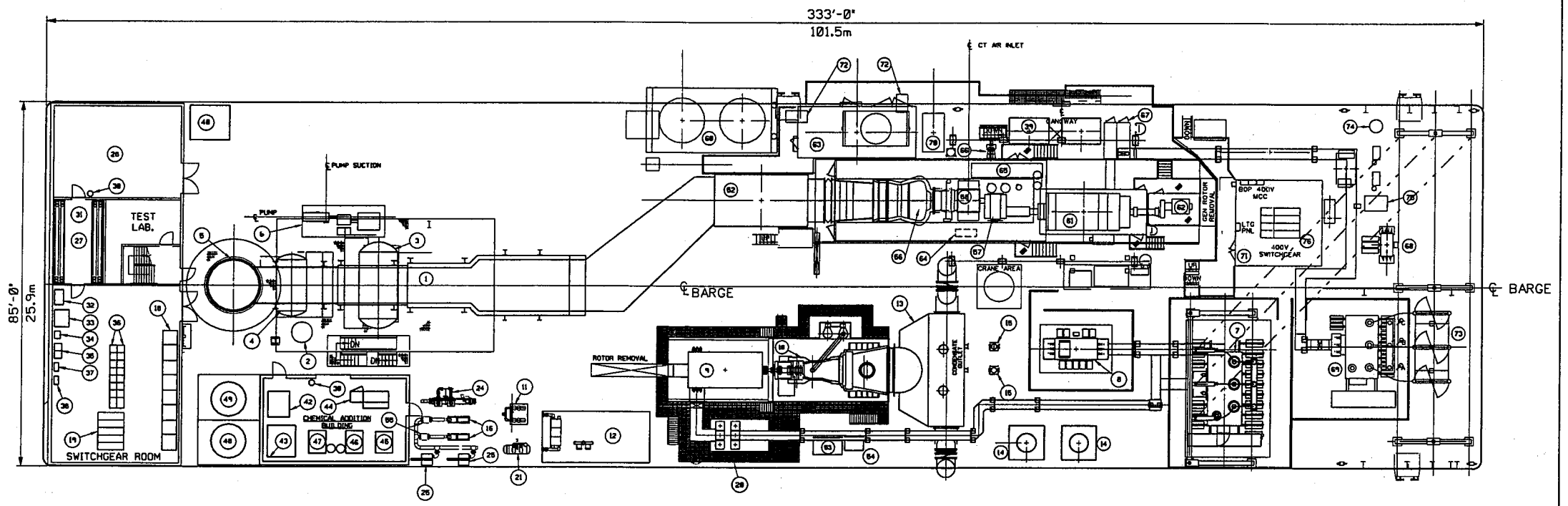
Our concept consists of developing a "barge-mounted" plant that would initially be located near Bel-Air, within the Dakar Port facility. When natural gas reserves are proven, another study would be initiated with the objective of proving feasibility of moving the plant vs. building a separate greenfields plant and retaining the location of the barge plant.

Initially, the barge plant will be fueled by natural gas condensate, with diesel backup. Gas condensate will be delivered to the existing Port of Dakar storage facilities.

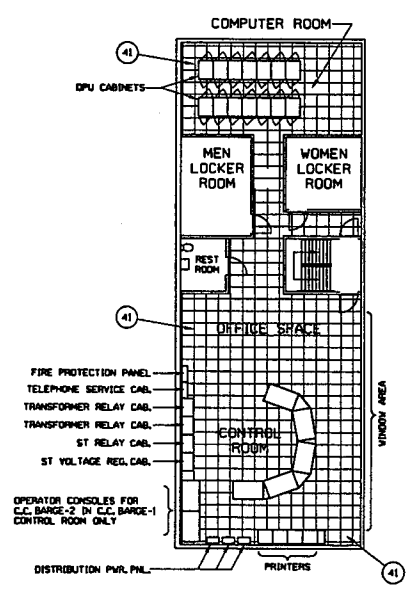
The proposed location for the proposed barge-mounted plant is near the fuel unloading facility in Dakar, in the slip of the abandoned Darse ex-A.C.D. facility, and within 500 m of SENELEC's Bel Air generating facility. A plan view of Port Dakar, identifying the barge location and Bel-Air plant, and the proposed general equipment arrangement on the barge, are shown on the pages following.

Construction of the entire barge assembly would be accomplished in a U.S. shipyard, and would probably be "dry-towed" to Port of Dakar, unloaded, towed by tugs to its final destination, securely moored, and all necessary connections made.

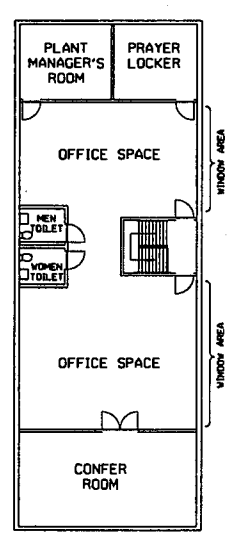

SENELEC
Bel-Air
Generating
Station
Barge Location
at Darse ex-
A.C.D. Facility
CONSERVERIES
DU SENEGAL
QUAI DE LA PECHE
BASSIN DE LA PE
DARSE NORD OUEST
MOLE 10
MOLE 4
MOLE 6
BASSIN
DES TORPILLEURS
Dock Flottant
TERMINAL
A CONTENEURS
PORTUAIRE
TERRE PL
Layout Showing Abandoned
Darse Ex-A.C.D. Facility
Scale 1:5000
0
100
200
300
meters



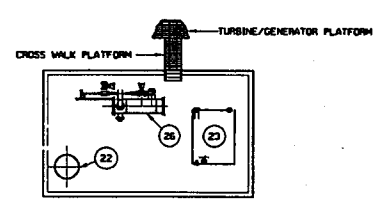
PLAN - MAIN DECK



ELEC/CONTROL BLDG
PLAN - 01 LEVEL
EMERGENCY EXITS REQUIRED
(TO BE DETERMINED BY NAVAL ARCHITECT)



ELEC/CONTROL BLDG
PLAN - 02 LEVEL
EMERGENCY EXITS REQUIRED
(TO BE DETERMINED BY NAVAL ARCHITECT)



CHEMICAL ADDITION BUILDING
ROOF

NOTES:

1. HEAT RECOVERY STEAM GENERATOR (HRSG)
2. HRSG BLOWDOWN TANK
3. HRSG HIGH PRESSURE DRUM
4. HRSG LOW PRESSURE DRUM
5. HRSG STACK
6. BOILER FEEDWATER PUMP
7. STEAM TURBINE GENERATOR STEP-UP TRANSFORMER
8. AUXILIARY TRANSFORMER
9. AIR COOLED GENERATOR WITH BRUSHLESS EXCITER
10. SINGLE CASE STEAM TURBINE
11. SCREEN WASH PUMP SKID
12. LUBE OIL SKID
13. STEAM CONDENSER
14. CIRCULATING WATER PUMP
15. CONDENSATE PUMPS
16. AUXILIARY COOLING WATER PUMP
17. NOT USED
18. 6.9 KV SWITCHGEAR
19. 480 V SWITCHGEAR
20. GENERATOR BREAKER
21. VACUUM PRIMING SYSTEM
22. AUXILIARY COOLING WATER HEAD TANK
23. GLAND STEAM SUPPLY SKID
24. GLAND STEAM LEAKOFF CONDENSER SKID
25. AUXILIARY COOLING WATER HEAT EXCHANGERS
26. STEAM JET AIR EJECTORS
27. BATTERY ROOM
28. ELECTRICAL/MECHANICAL WORKSHOP
29. CIRCULATING WATER MECHANICAL FILTRATION AREA
30. EYE WASH & SAFETY SHOWER
31. 125 V BATTERY
32. BATTERY CHARGER
33. UPS SYSTEM
34. UPS ISOLATION TRANSFORMER
35. 125 V D.C. DISTRIBUTION PANEL #1
36. 480 V MOTOR CONTROL CENTER
37. 125 V D.C. DISTRIBUTION PANEL #2
38. 480/230 V DISTRIBUTION PANEL
39. TRAVELING WATER SCREEN DRIVE
40. SEWAGE TANK AND PUMP
41. COMPUTER TYPE RAISED FLOOR SYSTEM
42. SODIUM BISULFITE FEED SYSTEM
43. SODIUM HYPOCHLORITE FEED SYSTEM
44. SAMPLING & ANALYSIS SYSTEM
45. PHOSPHATE SOLUTION FEED SYSTEM
46. OXYGEN SCAVENGER FEED SYSTEM
47. NEUTRALIZING AMINE FEED SYSTEM
48. SODIUM HYPOCHLORITE STORAGE TANK
49. SODIUM BISULFITE STORAGE TANK
50. NOT USED
51. AUXILIARY AIR FAN
52. NOT USED
53. OIL/WATER SEPARATOR AND SLOP TANK PUMP
54. OIL/WATER MONITOR AND PUMP
55. AUTOMATIC BACKWASH STRAINERS
56. COMBUSTION TURBINE
57. REDUCTION GEAR UNIT
58. TURBINE INLET DUCTING
59. TURBINE ROTOR AIR COOLER
60. LUBE OIL COOLER
61. GENERATOR
62. STARTING PACKAGE
63. ELECTRICAL ENCLOSURE/CONTROL PACKAGE
64. SEAL AIR COOLER
65. AUXILIARY LUBE OIL RESERVOIR
66. VAPOR EXTRACTOR
67. SWITCHGEAR
68. AUXILIARY TRANSFORMER
69. MAIN TRANSFORMER
70. FUEL OIL/WATER PURGE
71. SWITCHGEAR BUILDING
72. AIR CONDITIONER
73. DISCONNECT SWITCH
74. COMPRESSED AIR RECEIVER
75. COMPRESSED AIR DRYER
76. STATIC EXCITER ENCLOSURE

REV	DATE	DESCRIPTION	ORIGIN	CHECKED	LEAD DESIGNER	ENGINEER	LEAD DISCIPLINE ENGINEER	PROJ. ENGR. MANAGER	PROJECT MANAGER

STATUS OF DRAWING: PRELIMINARY

DEFINITION: REPRESENTS GENERAL DESIGN CONCEPTS BASED ON ASSUMPTIONS. REVIEWED NOT CHECKED.

CONSTRUCTION STATUS

DRAWN BY: VJB DATE: 02-12-99

CHECKED BY DATE

LEAD DESIGNER DATE

ENGINEER DATE

LEAD DISCIPLINE ENGR. DATE

PROJECT ENGINEERING MANAGER

PROJECT MANAGER

PARSONS
PARSONS ENERGY & CHEMICALS GROUP INC.
PASADENA OFFICE

CLIENT/PROJECT TITLE
U.S.T.D.A.
SENEGAL
COMBINED CYCLE PLANT

BARGE - MOUNTED ALTERNATIVE

SCALE

PARSON'S DWG. NO. BA-1

REV

ARCH | HVAC | I & C | ELECT | MECH | CIVIL | STRUC

The Total Barge-Mounted Project Cost of approximately $78.5 million, includes the project Capital Costs, and allowances for taxes and duties and project Development Fees. A preliminary assessment of financing potential was conducted. The barge project is most suitable to consider the advantages offered by the Maritime Administration of the Department of Transportation (MARAD), a US government agency that manages a "Federal Ship Financing Program".

A comparison of key financing parameters follows:

Parameter	Land-Based Plant	Barge-Mounted Plant
Total Capital Requirement	US$74.4 million	US$78.5 million
Assumed Debt-Equity Ratio	70:30	75:25
Financing Source	ECA-Lead	MARAD
1st Year Capacity Component[a]	US$8,500/kW/month	US$7,900/kW/month
Average 20 year tariff	US$ 50.77/MWh	US$ 52.66/MWh

Note a. Represents fixed part of tariff, including payments for debt service, equity return, and fixed operating costs.

Conclusions and Recommendations

If proven gas reserves were made available to the project, it is clear that the base analysis conducted in this feasibility study, including the selection and development of the Kayar site, would be viable. Considering the following:

- the gas reserve and supply is not proven,
- natural gas exploration continues with hope of finding large supplies,
- electric power is needed quickly in Senegal to support growing and pent-up demand, and
- electric generating capacity is needed to replace aging and obsolete facilities;

a barge-mounted plant may be a very appropriate for Senegal. In addition, the barge-mounted plant features:

- Competitive capital cost,
- Potential short implementation schedule,
- Better financing terms, and
- Possibility of relocation to Kayar or other suitable site near a producing gas supply location.

These conditions further underscore the attractiveness of barge-mounted plant as a viable alternative for Senegal. The preferred location is in the Port of Dakar, specifically at the Darse ex A.C.D. facility that has been abandoned for more than ten years.

If SENELEC desires to pursue a barge-mounted option, the following recommendations are offered:

1. Develop a tender document sent to a short list of medium-sized international bidders that includes this feasibility study, and specifies clearly:
   - Plant location;
   - Configuration, i.e., barge-mounted that can be moved to another location;
   - Fuel requirements (initial gas condensate/diesel, but equipped for, or convertible to, natural gas);
   - Performance requirements;
   - Emission limits;
   - Tariff requirements;
   - Division of bidder/owner scope;

   as well as schedule and all terms and conditions. Tender should request a development plan that includes sources of financing, contract/permit development, and scenarios to exploit future gas development. It should also allow the bidder to propose an alternate plan.
2. Develop a preliminary agreement with the Port of Dakar to secure an option for the recommended barge location, and include this commitment in the Tender Document.
3. Develop preliminary approvals from the environmental authorities, and include these approvals in the Tender Document.

SECTION 1: INTRODUCTION

This section introduces this final report, and provides background information on the project, Senegal, and SENELEC.

This report represents the work performed for the Senegal Independent Power Plant Feasibility Study. The report summarizes the analyses supporting the selection of the proposed project and briefly describes the selected plant and financing details. This report is based upon available information which is subject to change, particularly the natural gas situation and the gas turbine model selected for conceptual design.

This report should prove useful in providing the project basis, size, technology, fuel, design, capital cost and financial structure.

1.1 IPP FEASIBILITY STUDY

The objective of this feasibility study is the preparation of a financing memoranda, and supporting technical analysis, that will support the development of the Independent Power Plant (IPP) project. Funding for the feasibility study is provided by the US Trade and Development Agency (USTDA) and is being performed by a team lead by Parsons Energy & Chemicals Group Inc. Team members include Taylor DeJongh, a leading energy project finance advisor, and EMSI, an in-country engineering firm. The study is being performed directly for SENELEC, the national electric utility in Senegal.

The feasibility study is supported by strong technical, electrical system, environmental, economic, and financial analyses. The following specific tasks are being performed for this study:

1. Review of the Forecast System Demand
2. Evaluation of Fuel Sources
3. Selection of the Preferred Generating Options
4. Site Selection
5. Environmental Assessment
6. Electrical System Study
7. Capital Cost Estimate

8. Operating Cost Estimate
9. Financing Memorandum
10. Final Report

The report is organized along the lines of these feasibility study tasks with the following outline:

Section 1: Introduction - This section
Section 2: System Demand Forecast and Generation Planning Review
Section 3: Potential Fuel Sources
Section 4: Selection of Preferred Generating Options
Section 5: Electrical System Studies
Section 6: Site Selection
Section 7: Environmental Assessment
Section 8: Conceptual Design and Cost Estimate
Section 9: Financing Analysis and Plan
Section 10: Barge Mounted Power Plant

The last section covering the barge mounted power plant alternative was added because of the uncertainty of the natural gas fuel supply situation.

1.2 PROJECT BACKGROUND

SENELEC has a great need for new electric generation with power outages occurring on a routine basis. The expected electric demand growth is estimated as 5% per year. Over the next 10 years, SENELEC anticipates retiring over 120 MW, or approximately 45% of their presently installed capacity while the Interconnected Network demand plus losses is expected to grow by almost 130 MW. Many of the existing units have poor efficiencies, burn dirty heavy oil and are in poor condition. Two units already planned for addition are a 50 MW GTCC IPP in 1999, and a 200 MW hydro-electric unit anticipated in 2003, of which SENELEC owns 33%.

Historically, Senegal has had very little in the way of indigenous energy resources, necessitating the import of large quantities of petroleum products. However, in early 1997, the Government of Senegal announced the discovery of a significant natural gas reserve in the Thiés Region at Gadiaga. Although this reserve does not appear to be as large as first understood, other promising gas explorations are currently underway. In addition to natural gas, this study considered heavy oil, light oil, coal, and indigenous peat.

1.3 SENEGAL

With its capital city of Dakar located on the westernmost point of Africa, Senegal is a gateway to the continent. It has some of the best commercial facilities in West Africa, with good international and domestic transportation links. Although its industrial base is smaller than that of rival Cote d'Ivoire, many companies use Senegal as a regional center for West African operations. Senegal is also known as one of Africa's most politically stable countries - a functioning multi-party democracy has evolved since independence from France in 1960[1].

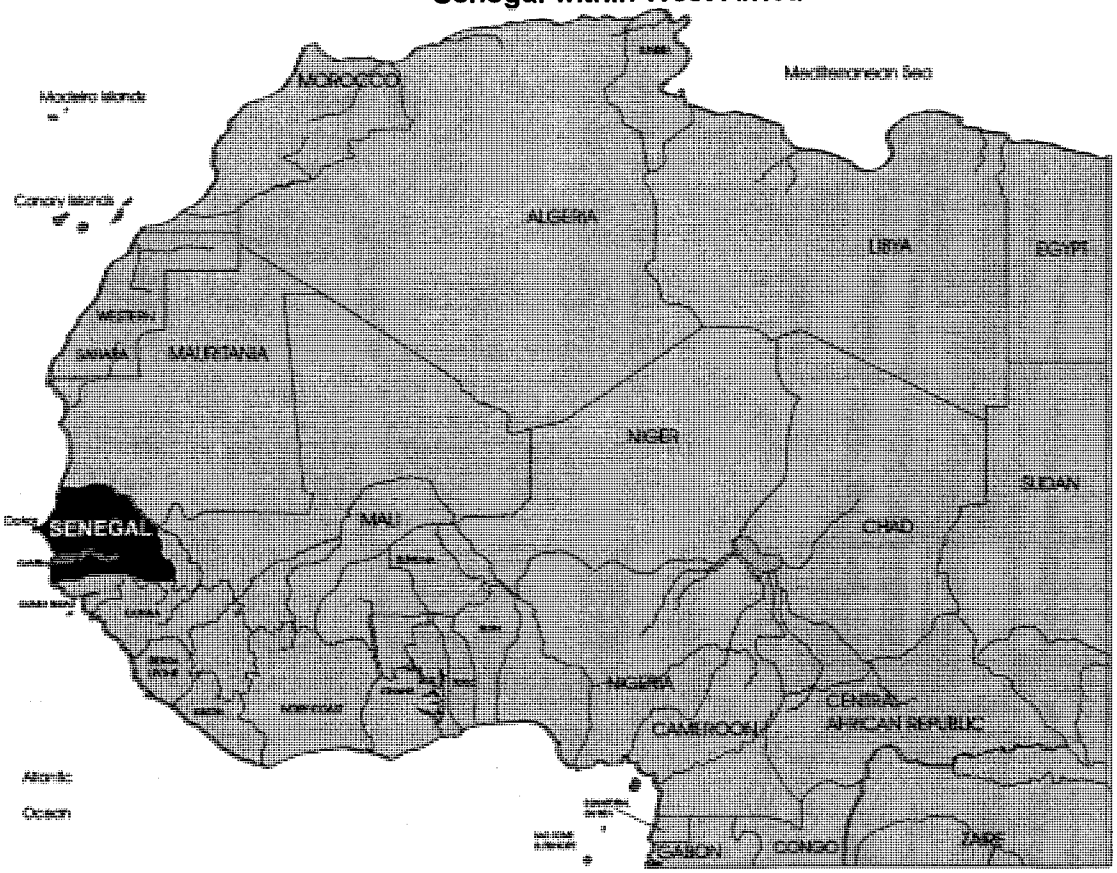
The Republic of Senegal lies on the bulge of western Africa, as shown in Exhibit 1-1. It is bounded to the north and to the northeast by the Senegal River, which separates it from Mauritania; to the east by the Faleme River, a tributary of the Senegal River, which separates it from Mali; to the south by Guinea and Guinea-Bissau; and to the west by the Atlantic Ocean. The Gambia forms an enclave within the Republic of Senegal about 32 kilometers (20 miles) wide and more than 320 kilometers (200 miles) long from the coast eastward. Senegal is located approximately between 12 and 16 degrees north latitude, and between 11 and 17 degrees west longitude and stretches 600 kilometers east to west, 400 kilometers north to south, forming an area of 203,793 square kilometers (78,684 square miles).

Windblown sand dunes cover parts of the country's coastal region. Fairly low, flat plains extend over most of the interior of Senegal. The country's highest point is in the Southeast, where the elevation is between 1,200 and 1,600 feet.

The country can be divided into four areas by geographical and geological features and climate zones. They are low land in the delta of the Senegal River which belongs to dry and/or semi-dry zone, central plateau mainly consisting of wide sandy places, heights in the south eastern area and low land in the tropical rain forest, and the Cap Vert Peninsula which is formed of hills and bare rocks and juts out into the Atlantic Ocean.

Most of the people live near the coast and in the Senegal Valley. The capital and largest city of Senegal is Dakar. Other cities of Senegal are Kaolack, Thies, Rufisque, and Saint-Louis. Climatic data for Dakar-Yoff and Theis is presented in Exhibit 1-2. In 1988, 38.6% of the population lived in urban areas, 61.4% lived in rural areas.

Exhibit 1-1
Senegal within West Africa



Dakar is located on Senegal's western most tip within the Cap Vert Peninsula and covers a northwest to southeast distance of 12 kilometers. With a population of approximately 1.9 million (as of 1995), approximately 23 percent of the country's total population is concentrated in Dakar. The nation's total population is estimated to be 8.8 million in 1998 (8.31 million as of 1995).

The Senegal population is estimated to grow at a rate of 2.6%/year between 1988 and 2010. Meanwhile the country-wide household electrification rate has increased from 20.3% in 1988 to 26% in 1995. Additional country information is presented in Exhibit 1-3.

Exhibit 1-2
Senegal Climate Data for Dakar and Theis

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Average	Extreme
DAKAR-YOFF (1961-1990)															
Temperature															
Max.	(C)	24.8	24.7	25.0	24.9	25.8	28.4	29.6	30.0	30.3	30.5	28.9	26.4	27.4	30.5
Min.	(C)	17.2	17.1	17.7	18.5	20.2	23.0	24.4	24.8	24.6	24.5	22.3	19.4	21.1	17.1
Ave.	(C)	21.0	20.9	21.4	21.7	23.0	25.7	27.0	27.4	27.5	27.5	25.6	22.9	24.3	
Max.	(F)	76.6	76.5	77.0	76.8	78.4	83.1	85.3	86.0	86.5	86.9	84.0	79.5	81.4	86.9
Min.	(F)	63.0	62.8	63.9	65.3	68.4	73.4	75.9	76.6	76.3	76.1	72.1	66.9	70.1	62.8
Ave.	(F)	69.8	69.6	70.4	71.1	73.4	78.3	80.6	81.3	81.4	81.5	78.1	73.2	75.7	
Humidity															
Max.	% RH	90	93	93	93	92	90	88	91	93	92	91	88	91.2	93
Min.	% RH	47	54	58	65	66	66	67	70	69	65	54	46	60.6	46
Ave.	% RH	69	74	76	79	79	78	78	81	81	79	73	67	75.9	
Theis (1981-1990)															
Temperature															
Max.	(C)	31.4	33.0	34.1	32.7	32.7	33.6	32.9	31.9	32.7	35.0	34.9	32.2	33.1	35
Min.	(C)	16.4	17.2	18.6	19.0	20.2	22.6	23.7	23.4	23.3	22.6	19.7	17.2	20.3	16.4
Ave.	(C)	23.9	25.1	26.4	25.9	26.5	28.1	28.3	27.7	28.0	28.8	27.3	24.7	26.7	
Max.	(F)	88.5	91.4	93.4	90.9	90.9	92.5	91.2	89.4	90.9	95.0	94.8	90.0	91.6	95.0
Min.	(F)	61.5	63.0	65.5	66.2	68.4	72.7	74.7	74.1	73.9	72.7	67.5	63.0	68.6	61.5
Ave.	(F)	75.0	77.2	79.4	78.5	79.6	82.6	82.9	81.8	82.4	83.8	81.1	76.5	80.1	
Humidity															
Max	% RH	73	78	81	85	87	92	92	95	97	96	89	81	87.2	97
Min	% RH	19	21	25	33	37	44	53	58	60	41	25	20	36.3	19
Ave.	% RH	46	50	53	59	62	68	73	77	79	69	57	51	61.8	

Exhibit 1-3
Senegal Country Data

	CY96	CY97 (E)	CY98 (P)
Populations (millions)	8.4	8.6	8.8
Population Growth (%)	3.0	2.7	2.7
Age Distribution	0-14 yrs (48%), 15-64 yrs (49%), 65 yrs and over (3%)		
Life Expectancy at Birth	54.6 yrs (male), 60.3 yrs (female)		
Literacy Rate	38.3%		
Religions	Muslim (94%), Christian, (5%), Animists (1%)		
Area	196,190 sq. km (total), 192,000 sq. km (land)		
Climate	Tropical; hot, humid; rainy (May-Nov); Dry (Dec-Apr)		
Terrain	Generally low, rolling, plains rising to foothills in SE		
Land Use	Arable land (12%), permanent pasture (16%), forest and woodland (54%), other (18%)		
Government System	Presidential republic under multiparty democratic rule		
Independence	4 April 1960 (from France)		
Languages- official: - other:	French Wolof (80%), Poular, Serer, Diola, Mandingo		
Work Week	Monday through Friday		
Main Resources	Fishing, tourism, peanuts and phosphates		

Notes: CY= Calendar Year, E= Estimate, P =Projected, N/A= Not Available.
Sources: References 2 and 3.

1.4 ECONOMIC SITUATION IN SENEGAL

The domestic economy in this small semi-arid country remains heavily dependent on agriculture, and thus the amount of rainfall, which may vary considerably from year to year. Phosphates, fish, and peanuts are the major exports. Tourism and services are also important foreign exchange earners.

Senegal's comprehensive economic reform programs, supported by the IMF, the World Bank, and other donors including France, Japan, and the United States, have produced some positive macroeconomic indicators since the January 1994 CFA franc devaluation. Annual GDP growth decreased slightly from 5.6 % in 1996 to 5.2 % in 1997 even though the target rate for growth was 6 %. The inflation rate in 1997 was 1.8%. Economic data for Senegal is summarized in Exhibit 1-4.

Exhibit 1-4
Senegal Domestic Economy Information

	CY96	CY97 (E)	CY98 (P)
GDP (USD billion)	4.4	4.8	4.7
GDP Growth rate (%)	5.6	5.2	5.5
Government Spending as percent of GDP (%)	18.2	17.8	17.7
Inflation	3.0	2.5	2.0
Unemployment	45.2	46.0	48.0
Foreign Exchange Reserves	N/A	N/A	N/A
Average Exchange rate for USD 1	550	550	600
Debt Service Ratio	18.6	19.6	18.7
U.S. Economic/Military Assistance (USD million)	26.3	27.0	27.0

Notes: CY= Calendar Year, E= Estimate, P =Projected, N/A= Not Available.
Sources: Reference 2.

Senegal has phased out most quantitative restrictions on imports, reduced tariffs, dismantled monopolies, liberalized the labor market, and is slowly privatizing state-owned industries to re-establish the conditions for sustained growth and increased private investment and competitiveness[1].

The Senegalese are generally well-disposed toward Americans, and are actively seeking U.S. trade and investment. In the past, the country's historic ties to France and its relatively small domestic market have limited U.S. business relationships.

France remains Senegal's largest trading partner, although its share of trade has been declining since the CFA devaluation. In 1997, France had a 30 % share of the USD 1.3 billion import market, followed by Nigeria 7.2 %, the United States 4.8 %, Spain 4.4 %, and India with 3.9 %. The United States runs a significant surplus in bilateral trade, exporting USD 55.7 million of goods to Senegal in 1996 and has exported USD 56.6 million in 1997. Major U.S. exports include rice, wheat, and other agricultural commodities, as well as petroleum products, computer equipment, used clothing, and cosmetics. Trade data is summarized in Exhibit 1-5.

Exhibit 1-5
Senegal Trade (USD Millions) Data

	CY96	CY97 (E)	CY98 (P)
Exports (FOB)	916.9	982.1	964.3
Imports (FOB)	1178	1262.3	1225.5
U.S. Exports (FAS) (CY)	55.7	56.6	60.0
U.S. IMPORTS (CIF)(CY)	5.4	5.0	6.6
U.S. share (%)	6.0	4.8	5.1

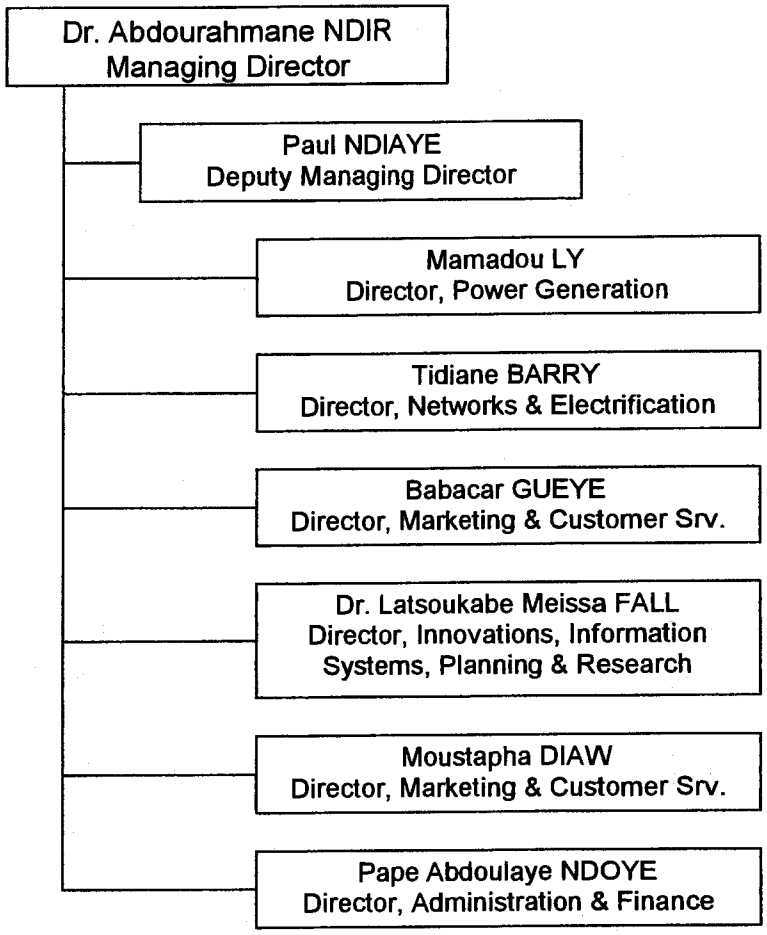
Notes: CY= Calendar Year, E= Estimate, P =Projected, N/A= Not Available.
Sources: Reference 2.

1.5 SENELEC

SENELEC, the Société Nationale d'Electricité du Sénégal, is a government-owned company that was created in 1983 through the merger of two companies: Electricité du Sénégal and Société Sénégalaise de Distribution d'Electricité. SENELEC became a corporation in 1998, with the government as the majority shareholder. The company's activities include the production, transmission and distribution of electricity throughout Senegal in order to ensure the development of the country. Its mission is to maintain and strengthen the country's competitive edge through the availability of reliable and affordable electricity[4].

SENELEC enjoys managerial, operational, and financial autonomy. It operates like a private company, receives no government subsidies, and utilizes its profits to finance both its operation and development of the country's electric system. SENELEC utilizes a board of directors comprised of government, industry, customers, and company representatives. The companies top level management is presented[5] in Exhibit 1-6.

Exhibit 1-6
SENELEC Organizational Structure



In early 1998, the National Assembly passed a law that established the framework for the privatization of SENELEC[1]. . The government of Sengal sold shares to a strategic partner, employees, and the public while retaining a portion for itself. The Government issued an international tender in late 1998 with four strategic partners having been selected for the final competition including[6]:

1. EDF (France)
2. Quebec Hydro and Elyo (Canadian-French consortium)
3. Cinergy-Eskom (American-South African consortium), and
4. Union Fenosa Acex.

The privatization was completed in April 1999, with Quebec Hydro and Elyo becoming the majority owner of SENELEC[7].

The privatization calls for the power generation to become fully independent, with SENELEC acting as the sole purchaser and distributor. GE Capital is the first party to enter into an power purchase

agreement with SENELEC with a 50 MWe build-own-operate-transfer (BOOT) power plant arrangement[1]. The plant is scheduled to begin operations by September 1999.

At the end of 1997, SENELEC had a total installed generating capacity of 316 MW. Most of this capacity is distributed at seven major power plants on an interconnected network. The utility also operates over 20 smaller plants in remote locations. The SENELEC generating units within the Dakar area are characterized in Exhibit 1-7. SENELEC serves a customer base of 329,000 with 2,145 employees. Of these employees, 450 have applied for the voluntary departure program implemented as part of the privatization program.

Exhibit 1-7
SENELEC Generating Units

Station/ Fuel Type	Unit Capacity, MW	Year of Startup	SO_2	NOx	Part.	CO
301-Cap des Biches (steam)/ Heavy fuel	25.80 x 1	1966	230 kg/h 8.9 kg/MWh	56.8 kg/h 2.2 kg/MWh	16.3 kg/h 0.63 kg/MWh	4.39 kg/h 0.17 kg/MWh
302-3 Cap des Biches (steam)/ Heavy fuel	28.10 x 2	1977/78	500 kg/h 8.9 kg/MWh	124 kg/h 2.2 kg/MWh	35.4 kg/h 0.63 kg/MWh	9.55 kg/h 0.17 kg/MWh
101 Bel Air (steam)/ Heavy fuel	9.20 x 4	1953	328 kg/h 8.9 kg/MWh	81.0 kg/h 2.2 kg/MWh	23.2 kg/h 0.63 kg/MWh	6.26 kg/h 0.17 kg/MWh
TAG 1 Cap des Biches (gas turbine)/ Diesel oil	15.0 x 1	1972	14.7 kg/h 0.98 kg/MWh	51.0 kg/h 3.4 kg/MWh	2. 85 kg/h 0.19 kg/MWh	3.45 kg/h 0.23 kg/MWh
TAG 2 Cap des Biches (gas turbine)/ Diesel oil	20.00 x 1	1984	19.6 kg/h 0.98 kg/MWh	68.0 kg/h 3.4 kg/MWh	3.80 kg/h 0.19 kg/MWh	4.60 kg/h 0.23 kg/MWh
TAG 3 Cap des Biches (gas turbine)/ Diesel oil	20.00 x 1	1995	19.6 kg/h 0.98 kg/MWh	68.0 kg/h 3.4 kg/MWh	3.80 kg/h 0.19 kg/MWh	4.60 kg/h 0.23 kg/MWh
401-2 Cap des Biches (diesel)/ Heavy fuel	18.00 x 2	1989	302 kg/h 8.4 kg/MWh	504 kg/h 14 kg/MWh	10.4 kg/h 0.29 kg/MWh	115 kg/h 3.2 kg/MWh
403 Cap des Biches (diesel)/ Heavy fuel	23	1997	193 kg/h 8.4 kg/MWh	322 kg/h 14 kg/MWh	6.67 kg/h 0.29 kg/MWh	73.6 kg/h 3.2 kg/MWh
BOOT Cap des Biches (gas turbine)/ Naphtha I	50	1999 In Constr.	10.5 kg/h 0.21 kg/MWh	215 kg/h 4.3 kg/MWh	12.0 kg/h 0.24 kg/MWh	11.5 kg/h 0.23 kg/MWh
TAG Bel Air (gas turbine)/ Diesel oil	37.00 x 1	1999 Proposed	36.3 kg/h 0.98 kg/MWh	126 kg/h 3.4 kg/MWh	7.03 kg/h 0.19 kg/MWh	8.51 kg/h 0.23 kg/MWh
105-6 Bel Air (diesel)/ Heavy fuel	4.5 x 2	1990	75.6 kg/h 8.4 kg/MWh	126 kg/h 14 kg/MWh	2.61 kg/h 0.29 kg/MWh	28.8 kg/h 3.2 kg/MWh
Total Nameplate Rating - Installed Total Nameplate Rating - by end of 1999	218.8 MW 306. MW					

Assumes an average heat rate of 11,318 kJ/kW-hr

SENELEC owns and maintains 11,000 km of transmission and distribution lines, most of which are concentrated in the Dakar

metropolitan area. The high, medium and low voltage transmission line lengths are 370 km, 3700 km and 7020 km respectively. The company is continuously upgrading its national grid in order to increase the rate of electrification. Only 50% of the country's urban areas and 4% of the rural areas have access to electricity. The government's objective is to increase these rates to 60% and 15% by the year 2005[4]. A graphic representation of SENELEC's transmission system is shown in Exhibit 1-8.

1.6 REFERENCES

1 "Country Commercial Guide (Dakar, Senegal) Fiscal Year 1999," prepared August 1998.

2 Government of Senegal/Ministry of Finance, IMF, Embassy Estimates, and USAID/Senegal, as presented in "Country Commercial Guide (Dakar, Senegal) Fiscal Year 1999", prepared August 1998.

3 CIA Factbook data on Senegal, found on www.odci.gov/cia/publications/factbook/sg.html, February 1999.

4 "Senegalese National Electric Corporation," a brochure published by Global Business Perspectives Inc., Northampton, Mass., 1998.

5 SENELEC Internet site, www.senelec.sn, February 1998.

6 Trip notes by L. N. Rubow, for a trip to Senegal from December 16 to 22, 1998.

7 "Electricity Shortage Worsens in Senegal," found on www.dakarcom.com/EconReports/electricity_shortage_worsens.htm, dated July 21 1999.

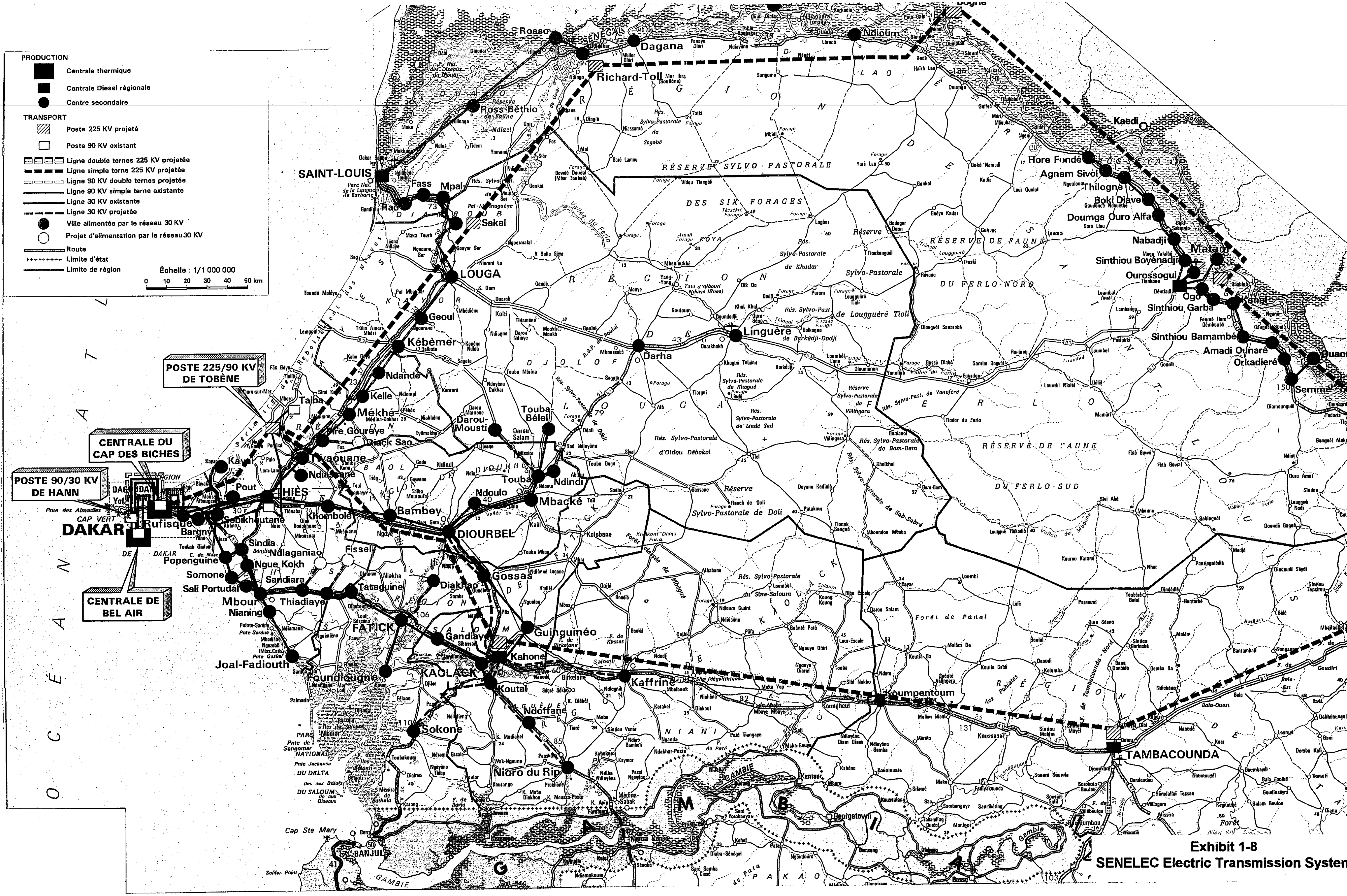


Exhibit 1-8
SENELEC Electric Transmission System

SECTION 2: SYSTEM DEMAND FORECAST AND GENERATION PLANNING REVIEW

Electric energy has been called the life's blood of a nation's economy. It can be shown that there is a high correlation between a country's use of energy and its living standards and Gross National Product. When there is a power failure, most productive work ceases in the area affected, manufacturing and process industries stop, transportation becomes difficult, foods begin to spoil, and in some instances, the social fabric begins to break down. Reliability of electric service is essential to a stable, growing national economy.

This section summarizes the Parsons Power comments on the SENELEC September 1994 and April 1996 Generation Plans. In general, the "Plan" and demand forecast appear well substantiated, and serve as a basis for the addition of capacity to the SENELEC system. Comments and recommendations on both the generation plan and demand forecast are made below.

To examine the existing SENELEC plan in view of these recommendations, and to provide an independent opinion, Parsons Power has modeled the SENELEC system and performed a resource analysis.

2.1 REVIEW OF THE SENELEC LOAD FORECAST

The forecast of the Long Term Demand for Electricity in Senegal as presented in the April 1996 report[1] and the April 1997 Generation and Transmission Master Plan[2], is quite properly based upon demographics and the planned expansion of electric service to areas not presently served[i]. The anticipated growth of the annual energy sales and peak energy requirements are developed for three scenarios: Expected, High, and Low Demands. The energy demand for these scenarios is presented Exhibit 2-1 for the sales (customer demand) for the Interconnected Network. The energy demand and peak demand

[i] The SENELEC PVS computer model simulates growth in the domestic and industrial sectors while recognizing the impact of large new projects. Within these sectors, the model further subdivides the demand growth into three geographical zones of similar socio-economic classification, and also by tension level.

including transmission and distribution losses (representing the required generation) are presented in Exhibit 2-2 and Exhibit 2-3 respectively.

Exhibit 2-1
Interconnect Network Energy Sales (GWh)

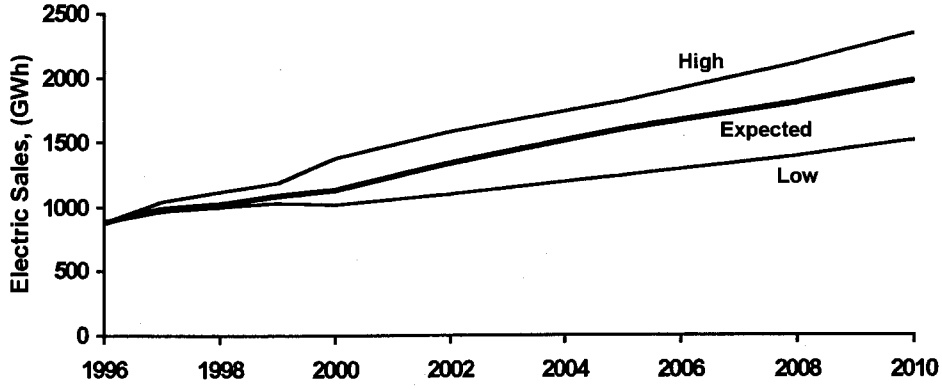


Exhibit 2-2
Interconnect Network Energy Sales and Losses (GWh)

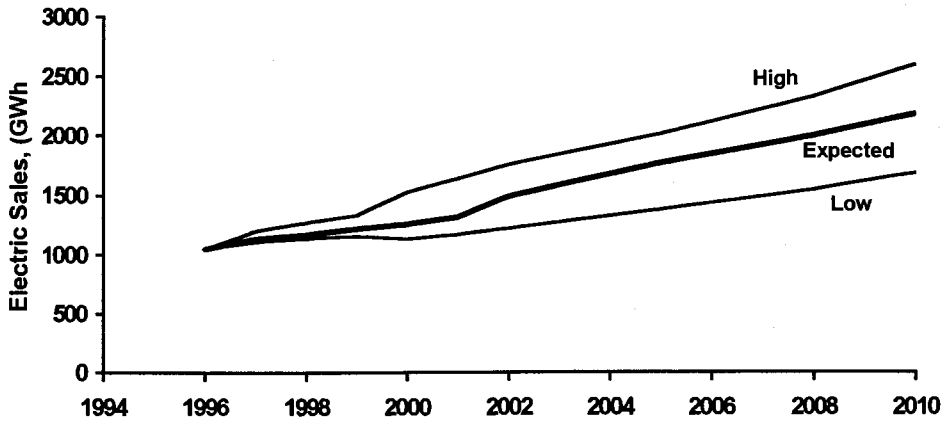
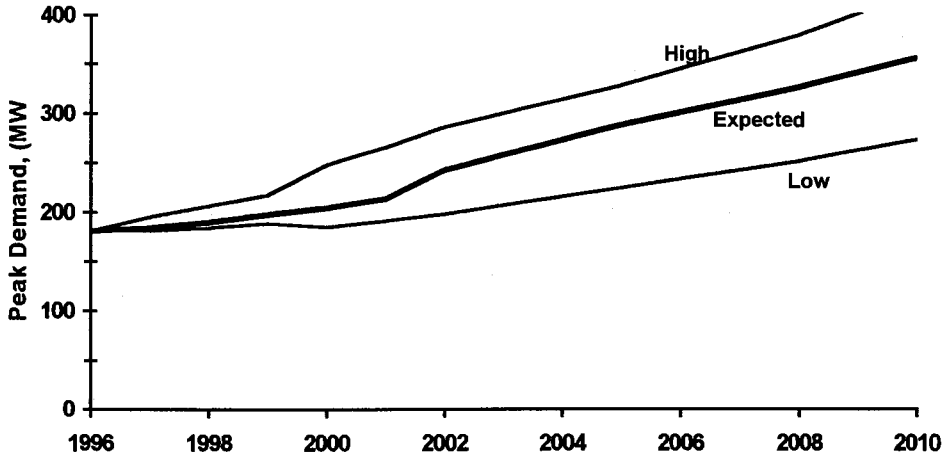


Exhibit 2-3
Interconnect Network Peak Demand (MW)



not presently served. The following comments have been made based upon the data and results of the demand projections.

2.1.1 Household Formation

The assumption used to relate the number of households to the population forecast, is that the ratio of households to the population will remain constant (shown in the tables in Annex I of the April 1996 report). With the increase in urbanization of the population as the economy matures, it would seem logical that the rate of household formation would be greater than the rate of population growth. Such a trend may be seen to a small extent by comparing the number of people per household in Region A to that of the other regions, 7.8 persons in Region A as compared to 9.1 and 8.7 in Regions B and C. The demand for electricity is more closely tied to the number of households, that is the number of customers, than to the number of people. If this supposition is indeed true, the increase in future demand could be above what has been projected.

2.1.2 Capacity Factor (Facteur de Charge)

The ratio of the average demand for power to the peak MW demand for power is the Capacity Factor. The assumption was made in the 1994 medium and long term planning report[3] that this factor will increase from 62% in 1994 to 66% in 2000. The 1997 Master Plan holds a constant capacity factor.

As electrification of a country proceeds and more customers are added to the network, and as the supply from the network becomes more reliable, the peak demand is more likely to grow faster than the energy demand, thereby, tending to lower rather than raise the Capacity Factor. This phenomena also tends to increase the future MW demand above what would be projected for a constant capacity factor.

In light of the importance of the capacity factor in the generation planning, discussions were held with SENELEC to better understand the capacity factor projections in light of the ongoing electrification and increasing use of electrical appliances. Upward pressure on the capacity factor is usually exerted only by large industrial loads. SENELEC acknowledged that this indeed is the justification for their Capacity Factor projections.

Two large Industrial projects considered by SENELEC are the Cayor Canal project, and the SAED project. The Cayor Canal project is designed for supplying Dakar with drinking water from Lake de Guiers estimated for operation in the year 2002. The SAED project is a project the will develop a irrigation system to irrigate 88,000 ha of crop land in

the Senegal River valley by the year 2015.[3] Both of these projects will add large pumping baseloads. Therefore the capacity factor assumptions do not appear to be unreasonable, and do in fact have a basis.

2.2 REVIEW OF THE SENELEC EXPANSION PROGRAM

Parsons has reviewed the 1994 expansion plan and made comments. This section documents the comments from that review. Subsequent to this review, SENELEC issued an updated plan in April 1997. Some comments have added while other comments have been modified in light of this new plan. The following subsections documents these comments.

2.2.1 Planning Criteria/Reliability Index

In the development of an expansion plan, the direct costs associated with increasing levels of reliability in the power system can be estimated with a great deal of confidence, but these costs, however, are only part of the story. The costs of providing an adequate, reliable supply of electrical energy must be balanced against the costs to the national economy of not providing service.

Electric systems are customarily planned using an adopted set of planning criteria. The underlying objective of establishing planning criteria is to provide a common basis upon which the quality of service provided to customers by system facilities can be compared and measured. The increased cost of new facilities and the scarcity and cost of capital has led to the development of various "reliability indices" which attempt to quantify the reliability of an electric system. The use of these indices has provided a consistent basis for planning system expansion in an economic manner. The planner's selection of the proper design level of a reliability index has evolved over a period of time by the observation of actual experience in their use coupled with intuitive judgment, rather than by precise analytical methods. The selection of the proper reliability index to be used by an individual system must be based upon the availability of capital for system facilities, the frequency and duration of outages of existing equipment, and the impacts and costs of outages to the system's customers.

In order to account for the random nature of unit outages, the cyclical nature of system load, and the scheduling of required maintenance, various probabilistic indices have been developed. Some of the more common of the probabilistic indices are:

- LOLE: Loss of Load Expectation [this index was called Loss of Load Probability (LOLP) when it was first introduced and is still frequently referred to as LOLP],
- HLOLE: Hourly Loss of Load Expectation
- EENS: Expected Energy not Supplied, and
- Frequency and Duration of Outages.

The analytical software used by SENELEC (PMP) to determine the optimal expansion plan, uses dynamic programming techniques to provide the expansion plan with the lowest present value of system costs for the selected reliability level including the cost of the Energy not Supplied.

The level of reliability chosen in this study for the development of the required generation installations, loss of load "three days per year", for the various expansion plans, is very low. A more common standard used, even in developing countries, is one day in five years, or 0.2 days/year, rather than three days per year. It is recommended that SENELEC consider evaluating the impact of raising the LOLE reliability level to 1 day/y, and further, to 0.2 days/y.

2.2.2 Energy Not Supplied

The cost to the national economy of the Energy-Not-Supplied (the Cost-of-Lapsing) is an important factor in determining the ultimate cost of an expansion plan. Studies have been made in various countries to determine an appropriate cost for this factor. In particular, see the published summary compiled by Aron P. Sanghvi[4], and the report of studies made for the Electricity Generating Authority of Thailand.[5] These studies would suggest that the price of the EENS should be in the closer to CFAF2000/kWh rather than the assumed CFA1106/kWh.

2.2.3 Base-Load Unit Size

The 1994 generation plan report recommends a unit size for base-load units of 90 MWe; however, support for the choice of this unit size (vs. 60 MW or 120 MW, for example) is not found in the report. In the year 2000 under the average growth scenario, 90 MWe represents 44 percent of the forecast peak load of the interconnected network, too high a percentage for a reliable system. The installation of multiple smaller units rather than fewer larger units will increase the reliability of the system since the forced outage of a unit represents a smaller percentage of the total. If the unit size is to be restricted to 30 percent of the network peak demand, units of 90 MWe should not be installed until the year 2006. If the ratio of unit size to total network demand is

allowed to reach 40 percent, the year is 2003. On the other hand, 60 MWe units would be applicable in the year 1999 at 30 percent, and today at 40 percent. From a reliability standpoint, 60 MWe units are preferable to 90 MWe units.

Parsons would have recommended that SENELEC consider a smaller unit, such as a 60 MWe unit, as well as the larger 90 MWe units, except during the course of this study, SENELEC issued their draft Master Plan that considers smaller units. Plants considered in the Master Plan include 10 and 20 MW diesels, 20 MW simple cycle gas turbines, a 50 and 60 MW gas turbine combined cycle, and a 90 MW oil-fired steam unit. This choice of unit sizes seems to be reasonable as long as the 90 MW unit is not added until the system capacity has grown sufficiently.

2.2.4 Manantali Dam

The operation of the Manantali Dam should be clarified, since it will be an important part of the SENELEC system. The reports do not state clearly how the hydro power will be delivered through the year. A meeting with SENELEC planning personnel provided this information for utilization in the Parsons Generation plan.

The electricity generated by the Manantali station will be shared by three states. It is unclear as to the extent that would be available to Senegal should significant demand not materialize in Mali and Mauritania.

The quantity of hydro-electricity disposable on the Interconnected Network is subjected to uncertainties attached to the Malian and Mauritanian demand for energy. In consequence, two possibilities can be envisioned[2]:

1. Mali and Mauritania will, at commencement of the hydro-electrical plant's operation, have sufficient demand to consume the hydro-electric production up to their officially determined shares (52% and 15% respectively, that is 67% of total production), the share allocated to Senegal would remain at 33%.
2. Mali and Mauritania demands remain relatively insufficient to absorb, during the first years of power station operation, their total respective shares, in which case, the balance will be added to Senegal's quota.

It is recommended that SENELEC continually monitor the demand growth in Mali and Mauritania and their need for the hydro-electric power to determine the power that will be available from Manantali.

2.2.5 Fuel Supply and Pricing

The SENELEC analysis did not appear to include any projection of fuel price increases over time. This is reasonable in light of recent World Bank projections. The cost of gas in the 1994 study was priced equivalent to oil, but other pricing situations should be studied to assess the potential benefit to SENELEC. There is a question as to how the government's fuel price stabilization mechanism affects SENELEC, and how it may affect the overall plan. Following discussions with SENELEC it was learned that SENELEC properly utilizes the economic cost of fuels (without subsidies or taxes) in their planning studies.

2.2.6 Variable Operation & Maintenance

In the 1994 plan, the only units for which a variable O&M cost has been included are the diesel units. All of the units, with the possible exception of the hydro units, should have the variable O&M recognized. In the 1997 Master plan, all units except the TAG units have variable O&M.

2.3 REVIEW RECOMMENDATIONS

It is recommended that SENELEC consider additional sensitivity studies for the High, Medium, and Low scenarios that would determine, singularly and in combination, the effect of:

- Increasing the price of Energy Not Supplied to CFA2000, and
- Raising the reliability level to one day/y.
- Additional hydro-electric generation from Manantali should the demand growth in Mali and Mauritania not develop as expected.

2.4 INDEPENDENTLY PERFORMED GENERATION PLAN

In order to provide an independent generation plan, Parsons performed a resource analysis. This analysis was performed using an Industry standard code, ELFIN, produced by the Environmental Defense Fund. The inputs and assumptions for the developed ELFIN model are documented in Appendix B. The results of this independent analysis are presented in Section 4 of this report.

2.5 REFERENCES

[1] "Forecasting Long Term Demand for Electricity in Senegal (1996-2010)," SENELEC Department of innovation planning and Equipment, Division of Background Economic Surveys, April 1996.

[2] "Generation and Transmission Master Plan," SENELEC Direction for Innovation, Planning and Equipment, Planning Division, Provisional Report, April 1997.

[3] "Medium and Long Term Equipment Program for Electrical Production on the Interconnected Network," National Electric Corporation (SENELEC), Sub-Department of Logistics, Management and Strategy, Provisional Report, September 1994.

[4] Sanghvi, Aron P. Optional Electricity Supply Reliability Using Customer Shortage Costs Criterion Inc., The Value of Service Reliability to Consumers, EPRI EA-4494, Electric Power Research Institute, Palo Alto, CA, USA, 1986.

[5] Sherman, Frank J. (Parsons Energy & Chemical), et al. The Cost of an Outage Utility Management & Corporate Planning Volume 1, Proceedings of the Sixth Conference on Electric Supply Industry, Jakarta, Indonesia, 1986.

SECTION 3: POTENTIAL FUEL SOURCES

This section summarizes the fuels available to Senelec and their related infrastructure. The fuels and fuel prices utilized in the Parsons' generation plan are documented in Appendix B.

Historically, Senegal has demonstrated very limited indigenous energy resources, necessitating the import of large quantities of petroleum products. The recent discovery of a potentially significant natural gas bubble has the potential to change this situation. Other indigenous fuels to Senegal include peat, and heavy crude.

The distribution of energy consumption in Senegal for 1992 is presented below:

Source of Energy	1000 TEP	Percentage (%)
Wood	613	41
Charcoal	234	16
Vegetable Waste	22	1
Electricity	70	5
Petroleum Products	566	38
Total	1505	100

Petroleum products display the highest utilization rate in the commercial energy resources (charcoal, electricity and petroleum products). However, 40% of the consumed petroleum products are utilized in electric generation.

The consumption of firewood and charcoal, mainly used by households, leads to over-exploitation of the natural forests.

Electrical energy represents a relatively small share of the total energy consumption (5%) but could become more important with the development of cheaper reliable electricity along with the electrification plan.

3.1 LIQUID FUELS

Refined product consumption in Senegal is approximately 20,000 bpcd. Products are imported from Nigeria and European refineries to supplement the output of the local refinery in Dakar. The SAR (Societe Africaine de Raffiage) refinery at M'Bao has a 17,000 bpd design capacity, but can only operate at 7,000 bpd. The plant has a catalytic reformer and hydrotreater, but is in poor condition. The refinery is jointly owned by Elf (41%), Shell (23%), Total (12%), Mobil (12%), and Banque de Senegal (12%). Elf operates the refinery, which is subsidized by the government of Senegal at a cost of $500,000 per year. The 1996 Cuneo e Associati Report to the World Bank recommends its closure.[1]

Currently, all liquid fuels used by SENELEC are provided by SAR through intermediaries such as Elf, Shell, Total, and Mobil. Recent changes in legislation have now allowed SENELEC to purchase fuel oil from sources.

Senegal has no crude oil production. Some oil exploration has taken place but the oil fields have proven small and/or uneconomical[1].

Based on discussions with Conoco, who has done exploratory work off the coast of southern Senegal, a significant amount of heavy crude oil has been discovered off-shore. This crude oil is, however, so viscous that it cannot be produced directly without steam heating to make it pumpable. Unfortunately this process of producing heavy oil, which is known as enhanced oil recovery (EOR), is very expensive, especially off-shore. Accordingly, it is not presently economically feasible to develop this newly discovered crude oil field and no timetable has been set by Conoco as to when they might commence production from this oil field.

Presently the two liquid fuels utilized in Senegal for electric production are the heavy and light fuel oils, and are discussed in Section 3.1.1 and 3.1.2 respectively. Naphtha is the anticipated fuel for the 50MW BOOT plant being developed by GE Capital and is discussed in Section 3.1.3. Gas condensate is a liquid fuel of growing importance that will grow in availability along with an increased natural gas production. Gas condensate is discussed in Section 3.1.4.

3.1.1 Heavy Fuel Oil and Fuel Oil Treatment

Major fuel characteristics of the heavy fuel oil utilized at the SENELEC power generating stations are presented in Exhibit 3-1.

Exhibit 3-1
Major Characteristics for the SENELEC Heavy Oil

Fuel Characteristics	Units	Heavy Fuel Oil	Heavy Fuel Oil[2]	Range[2]	Average[2]	Limit[2]
Date of Analysis or Data Source		March 93 Report[3]	01 Jan 97	Jun 96 to Jan 97	Jun 96 to Jan 97	Protocol Mar 19 94
Specific Gravity (15/4°C)		0.964	0.9536	0.943-991	0.956	0.995
Flash Point	°C	113	>70	>70	>70	66
Pour Point	°C	15	39	<0 -39	31	
Viscosity: 50 °C	cst	291.9	268	78-377	211	380
80 °C	cst	25.8	53.4	36-61	49.4	
Water	%	0.10	0.60	<0.1-**1.1**	0.3	1.0
Residual Carbon	%	11.0	6.1	4.2-17.5	7.2	18.0
Ash	%	0.14	0.02	0.02-0.08	0.03	0.12
Asphalt	%	4.31	1.4	0.7-9.5	2.7	11
Sludge	%	0.16				
Sediment	%	0.06	<0.01	<0.01-0.16	0.02	0.25
Sulfur	%	1.70	0.83	0.44-2.9	1.2	4.0
Hydrogen	%	11.4				
Carbon	%	86.3				
Nitrogen	%	0.35				
Sodium	mg/kg	48.1	14	7-110	35	130
Vanadium	mg/kg	134.3	25	11-236	66	350
Gross Calorific Value	kcal/kg	10,180	10,435	10,151-10,560	10,430	9,000-10,500
Net Calorific Value	kcal/kg	9,560	9,852	9,605-9964	9,848	

(Source: References 2 and 3)

Fuel cost is the largest operating expense of SENELEC's fossil fueled power production; the impetus is strong to use low cost heavy oil. However, heavy fuel oil is significantly poorer in quality than distillate oil, results in higher emissions, and also can contribute to operational and maintenance problems. Fuel oil treatment systems help to mitigate several of the problem area of this lower quality fuel oil.

Fuel Oil Treatment for Power Applications

Untreated heavy fuel oil is often high in concentrations of sodium, potassium, vanadium, and lead which are corrosive to a gas turbine hot gas path or to the cylinder liners and exhaust valves of a diesel engine. Untreated oil can be high in water, organic sludge, and organic and inorganic solids. Fuel oil treatment systems are able to mitigate these problems. Common fuel oil contaminants and their effect on a gas turbine[4] are presented below.

Contaminant	Problem	Component
Water/Micro-organism Solids Solids/Micro-organisms	Corrosion Erosion Clogging	Fuel System
Trace Metals - Sodium - Potassium - Vanadium - Lead	High T Corrosion	Hot Gas Path
Solids and Trace Metals	Ash Deposition	Hot Gas Path

Sodium and potassium are water soluble contaminants that can be removed with water washing. Vanadium is an oil soluble contaminant that can not easily be removed, so it is chemically bound with a magnesium additive. Typically, the magnesium additive (usually oil soluble magnesium sulphontates and aqueous magnesium sulphate) is required in a ratio of 3 parts magnesium for each part of vanadium[5]. Sodium restricts the effectiveness of the vanadium inhibitor, so the fuel must be low in sodium (<1.0 ppm). Treatment for sodium, potassium and vanadium are usually only required for heavy and crude oil, and not the lighter distillates.[6]

Ash forming impurities may be present in the fuel as oil soluble organometallic compounds, water soluble salts and solids. Ash formed during combustion may be deposited on the hot gas path in a gas turbine resulting in the loss of efficiency and power.

A major problem affecting gas turbine blade life for gas turbines operating on fuel oil at high temperatures is sulphidation attack. The presence of sulfur in the fuel, however, is not necessarily a problem as long as the sulfur remains in the gaseous phase. Sulphur becomes a serious problem in the turbine when sodium compounds, such as sodium sulphate, condense on the high temperature blades. Fuel sodium levels greater than 0.5 ppm will result in serious high temperature corrosion in aero-derivative turbines. Fuel sodium levels below 0.2 ppm will result in minimal corrosion provided the air sodium is maintained below 0.01 ppm.[7] In industrial (heavy) frame machines the fuel sodium level are normally specified as less than 1.0 ppm.

Consideration must be given to fuel sulfur when designing a heat recovery boiler for a gas turbine combined cycle in order to keep the cooled exhaust gas above the acid (H_2SO_4) dew point. This will slightly minimize the steam available for production.

Lead also poses a high temperature corrosion problem, however, it can not be removed or chemically bound. Lead is not naturally occurring in

fuel oils, but is instead a result of contamination with leaded fuels during shipping. Thus the control of lead in fuel oil is simply proper transportation practices.

Typical fuel limits for gas turbines and diesel engines are presented below:

Contaminant	Aero-derivative GT[8]	Frame GT[9]
Sodium, Potassium and Lithium	= 0.2 ppm	= 1.0 ppm
Vanadium	= 0.5 ppm	= 0.5, untreated > 0.5, treatment, but <100 ppm
Lead	= 1.0 ppm	= 2.0 ppm
Calcium	= 2.0 ppm	= 10.0 ppm
Other trace metals	NA	= 2.0 ppm
Sulfur, %	= 1.3 %	= 0.5 % for GTCC

Fuel Treatment is able to remove these problematic impurities to levels that are acceptable for use in gas turbine and diesel engines. A typical treatment for heavy fuel oil involves settling tanks, filtering, heating, water washing, and centrifuging. A typical treatment for distillate (light oil) fuel treatment consists of centrifuge separation without water washing.

Fuel treatment based on conventional centrifuges are limited to a density of 0.991. Alfa Laval offers the ALCAP separation system which is able to handle densities of up to 1.01. However, this system is not able to handle the large quantities of wash water. Therefore, to utilize heavy oil for a gas turbine would require a revised fuel specification with a specific gravity below 0.991. At the same time, the Vanadium specification would also have to be changed to 100 ppm, down from 350 ppm. With the present fuel supply, heavy oil cannot be recommended for use in gas turbines in Senegal.

3.1.2 Light Fuel Oil

Major fuel characteristics of the light fuel oil (diesel) utilized at the SENELEC power generating stations are presented in Exhibit 3-2.

Exhibit 3-2
Major Characteristics for the SENELEC Light Fuel Oil (Diesel)

Fuel Characteristics	Units	Light Fuel Oil
Specific Gravity (15/4°C)		0.868
Specific Gravity (API at 60°F)		31.43
Flash Point	°C	87
Pour Point	°C	8.5
Viscosity		
50 °C	cst	4.4
80 °C	cst	2.1
Water	%	<0.02
Residual Carbon	%	0.01
Ash	%	<0.01
Asphalt	%	<0.01
Sludge	%	<0.01
Sediment	%	<0.01
Sulfur	%	0.20
Hydrogen	%	12.8
Carbon	%	86.5
Nitrogen	%	0.03
Sodium	mg/kg	0.06
Vanadium	mg/kg	<0.01
Gross Calorific Value	kcal/kg	10,830
Net Calorific Value	kcal/kg	10,140

(Source: Reference 3)

3.1.3 Naphtha

Naphtha is a general term applied to various mixtures of liquid hydrocarbons with boiling points partially overlapping the ranges of gasoline and kerosene. The boiling range of naphtha is roughly 100 to 200°C (200 to 400°F). In petroleum refining, the naphtha fraction may be converted into more desirable fuel by reforming. The term "petroleum naphtha" may refer to refined, partly refined, or unrefined petroleum products.[10]

Petroleum naphthas are generally used as solvents for paints, dry-cleaning, industrial extractions, rubber production, and asphalt production[11], but can also be used in power generation. SAR will supply naphtha for fueling the GTI IPP[ii] gas turbine combined cycle. Generally, the production quantity of naptha is controlled to a degree by the type of crude that is purchased. The arrangement with GTI will result in an

[ii] GTI IPP - Greenwich Turbine, Inc. Independent Power Plant

estimated naptha shortage of 25,000 tonnes, which will be filled by diesel, or other product.

For the GTI project, 2 months of naptha supply will be kept on hand by Mobil/Shell (the winning Joint Venture bid). Fuel will be delivered by five dedicated trucks. At the end of 5 years, there is a price re-opening, with Mobil/Shell having the chance to meet competitors prices.

Discussions with SAR in the fall of 1997 indicated the price of naphtha would be approximately $4.30/MMBtu. The exact price and composition are, of course, unknown until the supplier is chosen.

3.1.4 Natural Gas Condensate

Natural gas condensates, or natural gas liquids, are the heavier hydrocarbons of natural gas that tend to condense into a liquid. The condensate is a mixture of light normal paraffin hydrocarbons, consisting mostly of propane (C_3H_8) through hexane (C_6H_{14}). The gas condensate is extracted from wet natural gas or casinghead gas by absorption in oil and can be utilized directly or subsequently fractionated into propane, butane, and natural gasoline.[10,11]

Condensate output is expected to increase in the coming years with increased natural gas exploration. Recently at the 1997 National Petroleum Refiners Association annual meeting, Kevin Lindemer, an analyst for Cambridge Energy Research Associates, stated that between 1997 and 2010, condensates will grow from 4% to about 8 % of total liquids. Later, he stated that condensates presently make up about 3 million bpd of the world's 70 MM bpd total liquid demand, and that this will grow to about 7.5 MM bpd of projected world liquids demand in 2010 of about 94 MM bpd.

A representative condensate analysis is presented in Exhibit 3-3.

Exhibit 3-3
Gas Condensate Analysis

Fuel Characteristics	Units	Typical Value
CH_4, Methane	(vol. %)	74.5
C_2H_6, Ethane	(vol. %)	8.3
C_3H_8 ,Propane	(vol. %)	4.7
C_4H_{10}, i-Butane	(vol. %)	0.9
C_4H_{10}, n-Butane	(vol. %)	1.9
C_5H_{12}, i-Pentane	(vol. %)	0.8
C_5H_{12}, n-Pentane	(vol. %)	0.6
C_6H_{14}, Hexane	(vol. %)	1.3
C_8H_{18}, Octane	(vol. %)	6.3
CO_2	(vol. %)	0.7
H_2S, Hydrogen Sulfide	(vol. %)	0.0
N_2	(vol. %)	0.0
Total	(vol. %)	100.0
Lower heating value	Btu/lb	20,300 (Estimated)
Lower heating value	Kcal/kg	11,300 (Estimated)

Source: Gas condensate analysis. Paloma, California. Ref. (11)

Gas condensate fuel is a very attractive option for the Senegal power plant, although minimum delivery quantities may require some additional market to be economical. GE Capital originally considered gas condensate for their BOOT, but the minimum delivery quantities were too large for the single 50 MWe plant[12].

3.2 NATURAL GAS

A small amount of natural gas is currently utilized by SENELEC and is provided by Tullow Oil. Explorations are underway to hopefully increase the utilization of natural gas within Senegal.

Fuel characteristics for the natural gas to be utilized at the proposed SENELEC power generating station are presented in Exhibit 3-4.

Exhibit 3-4
Natural Gas Composition

Fuel Characteristics	Units	Typical Value
N_2	(vol. %)	2.70
CO_2	(vol. %)	0.23
CH_4, Methane	(vol. %)	95.66
C_2H_6, Ethane	(vol. %)	0.91
C_3H_8Propane	(vol. %)	0.32
C_4H_{10}, i-Butane	(vol. %)	0.05
C_4H_{10}, n-Butane	(vol. %)	0.06
C_5H_{12}, i-Pentane	(vol. %)	0.01
C_5H_{12}, n-Pentane	(vol. %)	0.01
Sulfur	mg/ Nm^3	50 max
Density at 15°C	kg/ Nm^3	0.7071
Relative density (air = 1)		0.5772
Upper heating value	MJ/Nm^3	37.200
Lower heating value	MJ/Nm^3	33.500
Upper heating value	$kcal/Nm^3$	8,887
Lower heating value	$Kcal/Nm^3$	8,003

In early 1997, the Government of Senegal announced the discovery of a significant natural gas reserve of approximately 10 billion cubic meters (350 bcf) in the Thiés Region at Gadiaga. A map showing Gadiaga prospect is presented in Exhibit 3-5. PETROSEN[ii] (Société des Pétroles du Sénégal) intended to perform work that will better define the volume of this reserve. Ten billion m^3 natural gas corresponds to 93,000 GWh of thermal input:

$$(10x10^9\ Nm^3)(33.5\ MJ/Nm^3)(1\ W\text{-}s/J)(1h/3600s)= 93{,}000.\ GWh_{thermal}$$

Over 30 years, this averages to a level of 354 MWt. With a combined cycle efficiency of 45% and a capacity factor of 80%, this reserve would support the installation of approximately 200 MWe, or 300 MWe over a 20 year project life.

The potential development of such significant quantities of natural gas would reduce production costs, and put great pressure on the gas developer to price the fuel significantly below its current price. It is likely

[ii] PETROSEN was founded in May 1981 as a 100% state owned company controlled by the Ministry of Energy, Mines and Industry with a mission to manage all items related to exploration, production, transportation, trading and refinery of hydrocarbons, on behalf of the Government of Senegal.

that the fuel would be indexed to that of heavy or light fuel oils, the fuels it would displace.

At a meeting between Parsons and PETROSEN in October 1997, PETROSEN stated that preliminary interpretation of test data indicated a proven reserve of only 0.56 billion cubic meters (20 bcf). The oil companies were still in the process of performing their own evaluations, which was expected by the end of 1997.

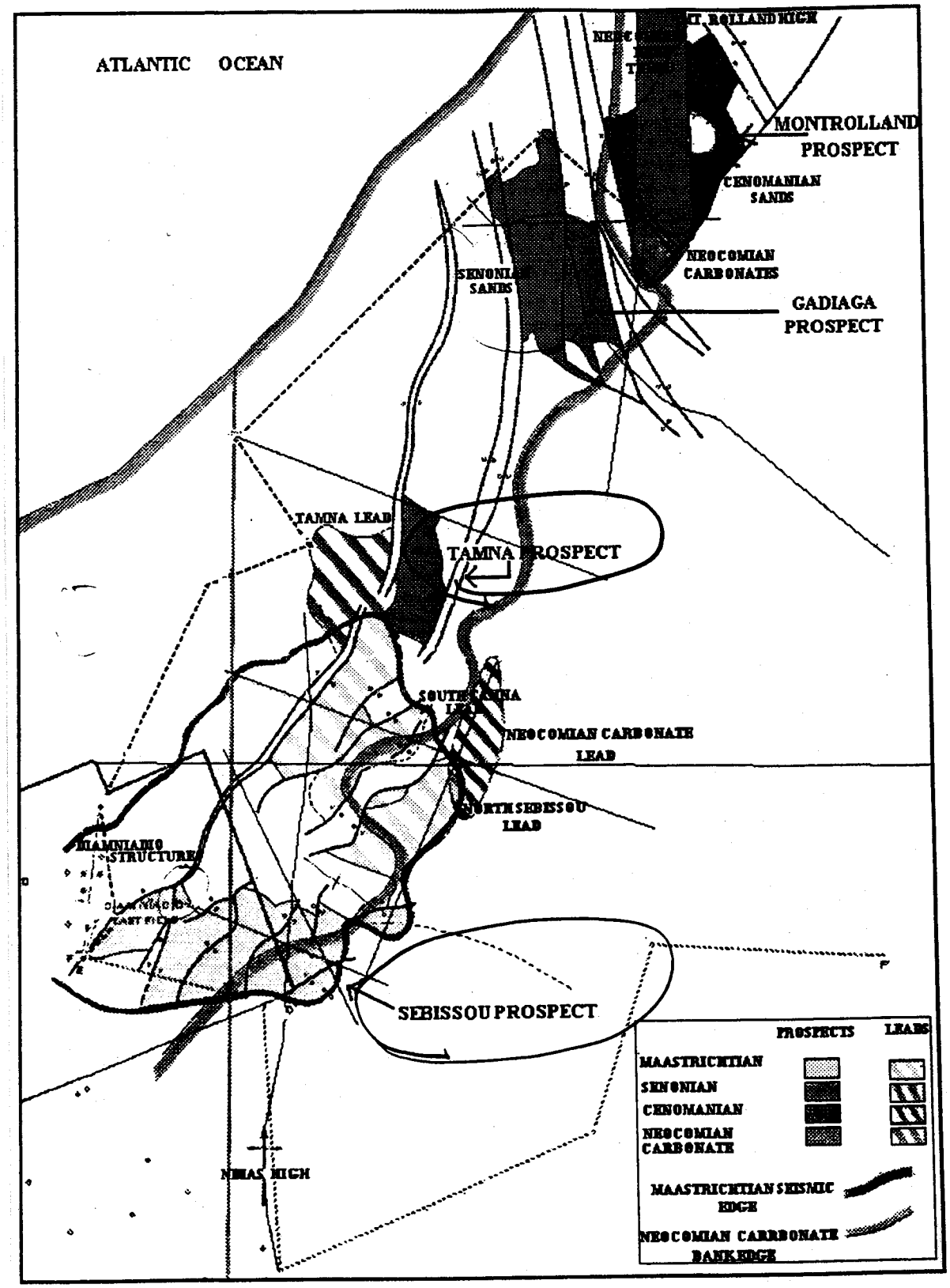
PETROSEN indicated that several other natural gas explorations would commence on November 20, 1997. The expectations of finding significant quantities at the time of the meeting was high. The location of these explorations in indicated in Exhibit 3-5. On this map a vertical line is indicated. To the east of this line are the PETROSEN franchise rights and exploration wells. West of the line are the Tullow franchise rights and exploration wells. The two PETROSEN explorations will be at Tamna, and Sebissiou. Tullow also is actively investigating other possible sites as indicated by the map. PETROSEN also has 25% ownership of the Tullow wells (recently, PETROSEN ownership has been reduced to 10%).

PETROSEN considers that the development of these wells could be 6 months or less. All of the engineering is complete and the costs have been established. The fields would be easy to connect to the existing pipeline. The quality of the gas in the Theis region is quite good. It is dry with no H_2S, and is nearly all methane. The C1 (CH_4) content is 96.4% with the C1 to C3 content at 99.4%. Two of these three wells have been drilled.

Since the initial announcement by the government, verification and exploration has continued. The existing producing well took on water (apparently not drilled at top, resulting in early closure). So, it is finished. A new well producing 5MMft^3/day (with some pressure problems) was thought to be larger, but found that it is "compartmented", meaning that the large reservoir is split into many parts, and so full exploitation will be too expensive.

To help with investment in exploration, a new partner solicited by government is Benton Oil from California, a pipeline and development contractor. Benton has an agreement to participate in the Theis Block (Tullow is Sebitopan Block) development. They will first perform some additional study. They will probably first drill south, when drilling resumes, probably mid-1999.

Exhibit 3-5
Natural Gas Prospects in the Region of Theis



Considering the current state of gas development in Senegal, albeit promising, the feasibility study is proceeding on the basis of locating the plant near the most likely sources of gas to be developed in the near future. However, the current slow development of gas suggests strong consideration of an alternative generation plant to meet Senegal's growing electric demands. This alternative is presented in Section 10.

3.3 SOLID FUELS

The development of solid fuel plants normally require significant infrastructure at a high initial investment cost. However, as a comparison two solid fuels were considered for the new facility. The solid fuel options include coal, and indigenous peat, which are described below.

3.3.1 Coal

A study performed by SEMA and ORGATEC corporations in 1981 examined the economics of importing 250,000 tons of coal into Senegal and determined a total delivered price to the power station of $100 per tonne. This was based on an FOB coal price of $60/tonne.

However, since 1981, coal prices have declined notably. In the 1994 generation plan[13], the quoted delivered price was $53/tonne, which was based on a FOB price of $28/tonne at Durban (South Africa), $18/tonne for marine transportation, $6/tonne for unloading, and $1/tonne for transportation.

Although coal can be delivered to Senegal from many sources that include South Africa, Brazil, Venezuela, the UK, and the United States, it appears that South Africa is one of the most likely sources. The South African coal production consistently exceeds the country's own domestic requirements, resulting in export of both bituminous and anthracite coal. The Republic of South Africa is one of the largest coal producers and exporters in the world.[14] In addition, per the World Bank, South Africa will have expanded terminal facilities in 1998[15].

World bank current dollar coal price projections are $40/tonne and $41/tonne for 1997, and 1998 respectively. Utilizing the same transportation and unloading costs mentioned above, this would raise coal costs to $65/tonne. Alternately, simply escalating the 1994 price of $53/tonne by 4%/yr yields approximately $60/tonne ($97).

Since coal is not expected to be competitive, a cost of $60/tonne was utilized in the generation planning. Should coal not be economic at this price level, it can be safely dismissed as not economic.

3.3.2 Peat

A significant peat deposit is contained in the northwest part of Senegal between M'Boro and Loumpol[16]. This deposit is estimated to contain approximately 23,481,000 cubic meters of recoverable peat, which is sufficient to provide enough fuel to generate 30 MW of electrical power for approximately 21 years. While the utilization of this local resource would lessen the need for additional imported fuel, the resource is only sufficient to supply a small portion of the fuel required by the proposed 60-90 MW electrical power plant. Accordingly using peat would necessitate the construction of two power plants, one of 30 MW fueled by peat and another one fueled by gas or oil as appropriate. Having to construct two power plants instead of one, as well as the development of a solids handling infrastructure for such a small plant would have a very negative impact on the required investment cost and would significantly increase the production cost of this roughly 90 MW block of electrical power. Therefore, the use of peat as a fuel has not been considered further.

3.4 FUEL PRICES

Economic fuel prices utilized in the Parsons generation planning model are based on 1997 prices per SENELEC and are presented in Appendix B.

3.5 REFERENCES

1 "African Refinery Desk Study," TDA Publication 96-007A, May 25, 1996.

2 "Bexcom International Preliminary Analyses for Heavy Oil", dated June to Nov 96, and January 01, 97.

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4 "Gas Turbine Fuel Treatment, Reference List," May 94, Alfa Laval.

5 "Gas Turbine Fuel Treatment, Fuel Conditioning Systems," Alfa Laval.

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7 "Gas Turbines in Industry: Fuel Handling," BP, MP 564/77, January 1977.

8 "Liquid Fuel for General Electric Aircraft Derivative Gas Turbines in Industrial Applications," General Electric Company, Marine & Industrial Engine Projects Department, MID-TD-0000-2, August 1985.

[9] "251B11/12 Econopac Application Handbook," Published by Westinghouse

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[11] The Chemistry and Technology of Petroleum, James G. Speight, 2nd Edition, 1991.

[12] Trip Report of L. N. Rubow to Senegal covering December 16 to 21, 1998.

[13] "Medium and Long Term Equipment Programme for Electrical Production on the Interconnected Network," National Electricity Corporation (SENELEC), Sub-Department of Logistics, Management and Strategy, Provisional Report, September 1994.

[14] Combustion Fossil Power, published by Combustion Engineering, Inc., ABB, 1991.

[15] "Commodity Markets and the Developing Countries, A World Bank Quarterly, August 1996."

[16] Socomine Peat report of December 1983 and the MC-W Energie-Consult GMBH report.

SECTION 4: SELECTION OF PREFERRED GENERATING OPTION

A review of the existing SENELEC Master Plan was presented In Section 2. An independent resource analysis was performed by Parsons to provide a basis for the independent power project. This section summarizes the process utilized in selecting a generation option for addition to the SENELEC system based on inputs from least cost analysis generation planning and electric stability analyses.

4.1 SELECTION METHODOLOGY

The primary tool used in the analysis of options is the ELFIN generation planning computer program. An ELFIN model was developed based upon information made available by SENELEC and characterizes the existing system load patterns, demand projections, losses, plant performance, planned maintenance, forced outages, resource additions (including the GTI BOOT and the Manantali Hydro station), take-or-pay units, unit retirements, and available fuels and costs. Details of the developed model are presented in Appendix B.

ELFIN is a generation planning and resource optimization computer program which is based on a probabilistic load duration curve simulation method that models multiple subperiods within typical weeks. The model dispatches production resources to meet the electric demand described by the input hourly load curve, taking into account both planned and unplanned outages.

The ELFIN program performs maintenance scheduling, commitment, and a detailed economic dispatch of the modeled units and is capable of determining fuel costs, shortage costs, fixed and variable O&M costs, capital costs, marginal energy costs, loss of load probabilities, energy not served, reserve, and emissions, among other things.

One powerful feature of the ELFIN computer model is the automatic resource planning optimization feature. ELFIN's optimization algorithms can determine the optimum mix of existing and new resources that will serve the system demand at the lowest possible total cost (as determined by cumulative discounted net present value of production, shortage and capital costs over the study period.) ELFIN offers several optimization options.

Europe. A sensitivity to the natural gas price is presented in Section 4.4. Additional information on fuels is presented in Section 3.

The optimized additions for both of these scenarios are presented in Exhibits 4-2 and 4-3 for the first ten years of the simulation.

Exhibit 4-2
Resource Additions for the Current Gas Price Scenario

Unit/year	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
60 MW HO-fired diesel				1				1		
90 MW HO-fired diesel										1

Exhibit 4-3
Resource Additions for the Reduced Gas Price Scenario

Unit/year	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
60 MW gas-fired GTCC				1				1		
90 MW gas-fired GTCC										1

These results are consistent with our expectations. High gas prices favor the heavy oil burning diesel engines. Low gas prices favor the gas-fired gas turbine combined cycles. With the current gas price, the diesel units are preferred over the heavy oil fired steam turbines, because of their greater, and fairly level efficiency over the load range. The coal units were determined not to be cost effective.

A great similarity can be seen between the two expansion plans. That is, the timing and size of the unit additions is identical between the different fuel price scenarios for the first ten years. This pattern departed for the subsequent years, which is not unexpected in light of the different performance values. However, since the purpose of this analysis is to focus on the timing of new unit additions, the optimizations seem to be very consistent.

Environmental characteristics favor the gas turbine option burning gas over the diesel option burning high sulfur fuel oil. The likely site for the new plant is on the northern side of the country, and the prevailing wind would bring pollution inland. The modeling effort did not account for environmental externality differences between options, and therefore, if the diesel option were selected, the permitting and financing hurdles must be investigated before such a project decision could be made. Site characteristics are discussed in Section 5.

A presentation of some key calculated results from these expansion plans are presented in Exhibits 4-4 and 4-5.

These exhibits reveal that the two expansion plans allow the loss of load probability (LOLP) to exceed the SENELEC criteria of 3 days/year in the year 2005 with values of 3.05 and 3.95 days/year for the diesel and GTCC plans respectively[1]. In order to meet the limit, Parsons recommends that the year 2005 additions be accelerated to some time in the year 2004, perhaps midyear in order to be meet the year-end peak demands. This decision should, of course, be continually re-evaluated through future generation planning activities, which will account for the realized demand growth and unit additions/retirements.

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[1] In Section 2, Parsons suggests that Senelec consider reducing their loss of load probability (LOLP) reliability limit from 3 days/year to something as low as 0.2 days/year. The analysis that follows displays values of up to 3.05 (Diesel) and 3.95 days (GTCC).

The two values in excess of 3 days per year were produced by the ELFIN generation planning program. ELFIN algorithms do not directly limit the calculated LOLP. Instead, in the generation planning/optimization mode, ELFIN acts to minimize the total system cost of which the cost of energy not served (CENS) is a part. For the base analysis, Parsons utilized the SENELEC value for the Cost of Energy not served of CFA1106/kWh. This value allowed the LOLP to occasionally exceed 3 days.

A higher CENS value would have caused capacity addition at an earlier date, thus reducing the calculated LOLP. Although for the purpose of selecting the best option to implement, the CENS was demonstrated as not being a critical parameter via a sensitivity study documented in Exhibit 4-10.

Exhibit 4-4
Diesel Configuration - Nominal Input

Year	Installed NetCap. (MW)	Net System Peak (MW)	Required Energy (GWh)	Energy Produced (GWh)	Energy Not Served (GWh)	LOLP (days)	Res. After Forced (%)	Ttl Prodct'n Cost (M$)
1998	260.1	190.1	1,166.0	1,163.2	2.80	8.53	10.5%	$68.650
1999	294.1	198.2	1,215.6	1,215.1	0.54	1.82	23.0%	$70.289
2000	307.1	204.4	1,256.9	1,256.4	0.54	1.59	27.2%	$70.648
2001	367.1	213.4	1,308.4	1,308.3	0.09	0.30	39.3%	$71.515
2002	360.7	241.9	1,483.4	1,483.1	0.34	0.99	26.3%	$78.912
2003	409.9	256.5	1,572.7	1,572.5	0.17	0.63	34.6%	$73.866
2004	394.9	271.9	1,671.8	1,670.8	0.97	3.05	22.4%	$79.067
2005	429.1	288.2	1,767.3	1,767.1	0.23	0.83	26.3%	$81.237
2006	429.1	300.2	1,840.5	1,840.0	0.48	1.64	21.3%	$84.461
2007	491.0	312.6	1,916.7	1,916.6	0.05	0.16	29.9%	$87.334

Exhibit 4-4
Diesel Configuration - Nominal Input (Cont'd)

Year	Fuel (TBtu)	Fuel (M$)	Var. O&M (M$)	ENS Cost (M$)	Var. cost (M$)	Fixed Cost (M$)	Ttl Production (M$)	Annual. Cap. Cost (M$)	Cum. System NPV (M$)
1998	14.3	$47.12	$2.25	$5.74	$55.11	$13.54	$68.65	$0.00	$62.41
1999	14.4	$45.59	$3.69	$1.11	$50.39	$19.89	$70.29	$0.00	$120.50
2000	13.2	$41.69	$4.51	$1.11	$47.32	$23.33	$70.65	$0.00	$173.58
2001	12.5	$38.86	$6.14	$0.19	$45.18	$26.33	$71.52	$7.33	$227.43
2002	14.6	$45.78	$6.76	$0.69	$53.23	$25.68	$78.91	$7.33	$280.98
2003	12.2	$43.65	$6.79	$0.35	$50.79	$23.07	$73.87	$7.33	$326.82
2004	13.2	$47.14	$7.17	$1.99	$56.29	$22.77	$79.07	$7.33	$371.15
2005	13.4	$47.17	$8.83	$0.47	$56.47	$24.77	$81.24	$14.66	$415.89
2006	14.1	$49.41	$9.29	$0.99	$59.69	$24.77	$84.46	$14.66	$457.93
2007	13.9	$48.52	$10.91	$0.09	$59.53	$27.81	$87.33	$25.24	$501.33
2036									$1072.9

Exhibit 4-4
Diesel Configuration - Nominal Input (Cont'd)

Year	SO2 (Tons)	NOx (Tons)	CO (Tons)	Particulate (Tons)
1998	7,971	5,536	1,853	682
1999	6,995	5,770	1,760	622
2000	6,257	5,312	1,585	561
2001	5,897	6,618	2,331	528
2002	7,137	7,510	2,635	633
2003	5,706	7,192	2,648	514
2004	6,281	7,694	2,838	562
2005	6,441	9,152	3,579	574
2006	6,814	9,668	3,797	606
2007	6,796	11,130	4,562	602

Exhibit 4-5
NG GTCC Configuration - Base

Year	Installed Net Cap. (MW)	Net System Peak (MW)	Required Energy (GWh)	Energy Produced (GWh)	Energy Not Served (GWh)	LOLP (days)	Res. after Forced (%)	Ttl Prodct'n Cost (M$)
1998	260.1	190.1	1,166.0	1,163.2	2.80	8.53	10.5%	$68.650
1999	294.1	198.2	1,215.6	1,215.1	0.54	1.82	23.0%	$70.289
2000	307.1	204.4	1,256.9	1,256.4	0.54	1.59	27.2%	$70.648
2001	367.1	213.4	1,308.4	1,308.2	0.20	0.57	40.7%	$74.249
2002	360.7	241.9	1,483.5	1,483.0	0.50	1.28	28.7%	$82.076
2003	409.9	256.5	1,572.7	1,572.4	0.32	0.95	37.5%	$76.902
2004	394.9	271.9	1,671.8	1,670.3	1.49	3.95	24.9%	$83.016
2005	429.1	288.2	1,767.3	1,766.6	0.69	1.77	29.7%	$87.807
2006	429.1	300.2	1,840.5	1,839.3	1.17	2.83	24.6%	$91.671
2007	491.0	312.6	1,916.7	1,916.3	0.43	1.00	37.7%	$97.562

Exhibit 4-5
NG GTCC Configuration - Base (Cont'd)

Year	Fuel (TBtu)	Fuel (M$)	Var. O&M (M$)	ENS Cost (M$)	Var. cost (M$)	Fixed Cost (M$)	Ttl Production (M$)	Annual. Cap. Cost (M$)	Cum. System NPV (M$)
1998	14.3	$47.12	$2.25	$5.74	$55.11	$13.54	$68.65	$0.00	$62.41
1999	14.4	$45.59	$3.69	$1.11	$50.39	$19.89	$70.29	$0.00	$120.50
2000	13.2	$41.69	$4.51	$1.11	$47.32	$23.33	$70.65	$0.00	$173.58
2001	12.9	$42.74	$5.37	$0.41	$48.52	$25.73	$74.25	$6.70	$228.86
2002	15.0	$50.08	$5.88	$1.03	$56.99	$25.08	$82.08	$6.70	$283.99
2003	12.8	$48.22	$5.55	$0.65	$54.43	$22.47	$76.90	$6.70	$331.18
2004	13.7	$51.84	$5.94	$3.06	$60.84	$22.17	$83.02	$6.70	$377.21
2005	14.0	$55.66	$7.16	$1.42	$64.24	$23.57	$87.81	$13.40	$424.42
2006	14.5	$58.16	$7.53	$2.41	$68.10	$23.57	$91.67	$13.40	$468.98
2007	14.5	$61.79	$9.01	$0.88	$71.68	$25.89	$97.56	$22.28	$515.19
2036									$914.90

Exhibit 4-5
NG GTCC Configuration - Base (Cont'd)

Year	SO2 (Tons)	NOx (Tons)	CO (Tons)	Particulate (Tons)
1998	7,971	5,536	1,853	682
1999	6,995	5,770	1,760	622
2000	6,257	5,312	1,585	561
2001	5,263	5,228	1,617	491
2002	6,213	5,769	1,754	575
2003	5,156	5,422	1,734	483
2004	5,409	5,632	1,788	509
2005	4,539	5,752	1,859	453
2006	4,603	5,870	1,887	463
2007	3,190	5,823	1,897	368

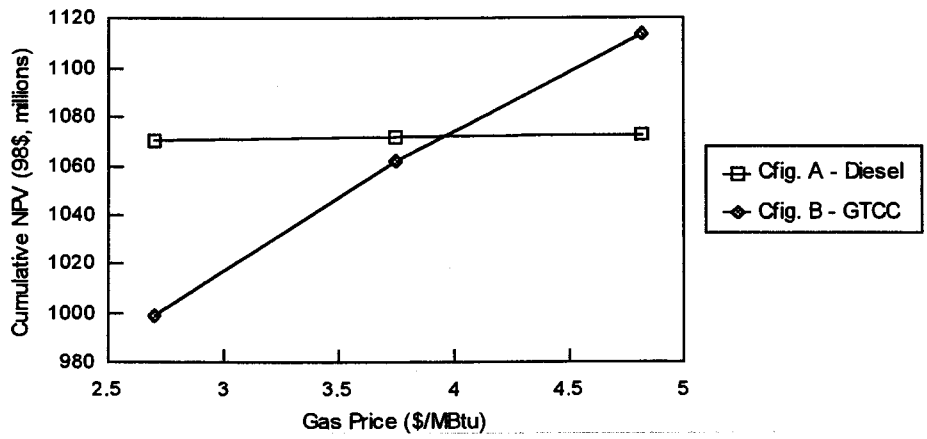
4.4 SENSITIVITY ANALYSIS

A sensitivity analysis was performed on the two optimized, or base, scenarios. Parameters that have been examined include gas price, capital costs, variable O&M, fixed O&M, the cost of energy not served, and the discount factor. Other sensitivities may be added at a later date.

Before performing the sensitivity study, the minor differences in the last years in the expansion plan were unified, so the sensitivity analysis would focus on the impact resulting from the basic selection of technology within the first 10 years of analysis. Rerunning the unified plans resulted in insignificant change the cumulative NPV of the base plans. This slight change will normalize the plans without changing the relative difference.

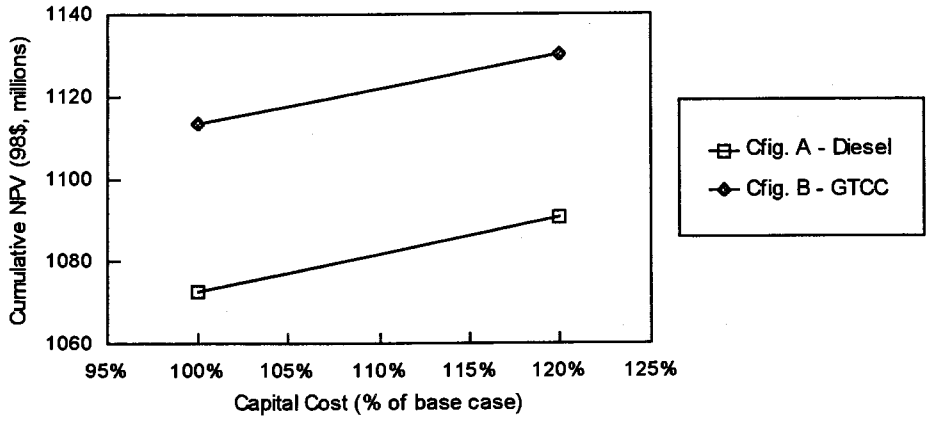
The natural gas price sensitivity, presented in Exhibit 4-6, is perhaps the most interesting. The price of natural gas is clearly central to the option selection. Natural gas prices above approximately $3.95/MMBtu support the selection of the diesel technology. Below this price, gas turbines are favored. While changing conditions and assumptions could result in a different "cross-over" point, it is clear that the current gas price of $4.81/MMBtu would not support an investment in a large gas-fired generating facility.

Exhibit 4-6
Gas Price Sensitivity



The sensitivity on capital cost, presented in Exhibit 4-7, is also interesting. Should the capital cost of either the 60 and 90 MW diesel or gas turbine projects be increased by 20%, the cumulative net present worth of costs would also increase by US$16 to 18 million. A change of this magnitude is roughly equivalent to a natural gas price change of US$0.30/MMBtu.

Exhibit 4-7
Capital Cost Sensitivity



Examination of the remaining sensitivity plots show a relative lack of importance with respect to these parameters, as shown in Exhibits 4-8 and 4-9. A 20% increase in the variable O&M rates for the new resources shows very little impact on the CNPV of costs. A 20% increase in the fixed O&M rate is only slightly more significant.

Exhibit 4-8
Variable O&M Cost Sensitivity

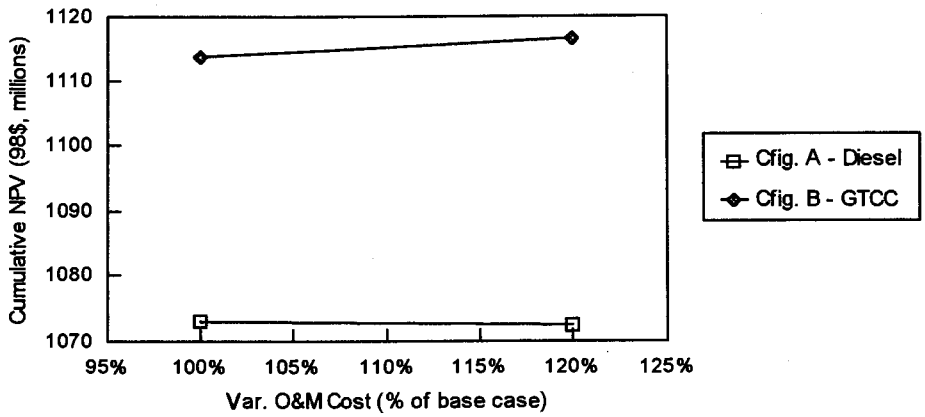
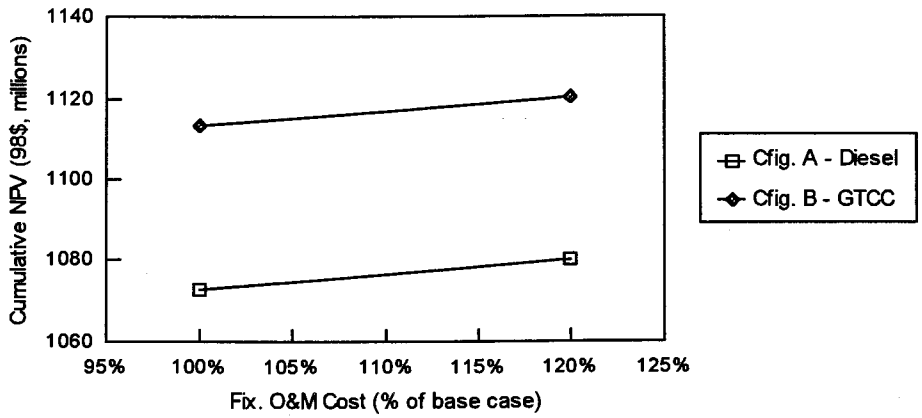
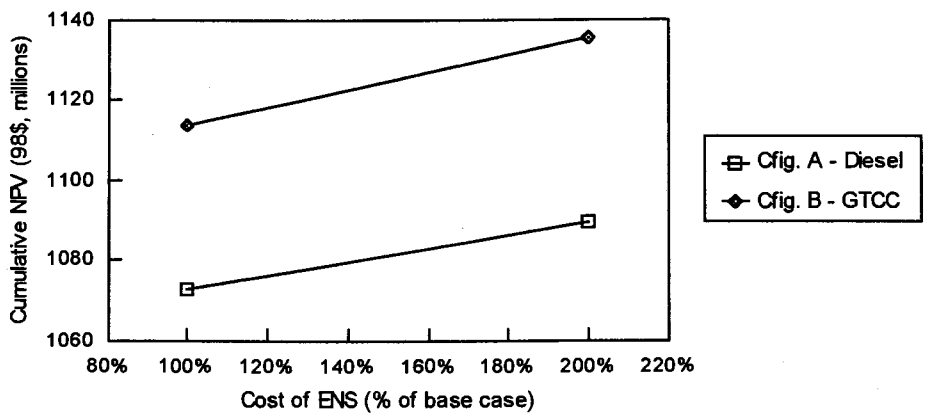


Exhibit 4-9
Fixed O&M Cost Sensitivity



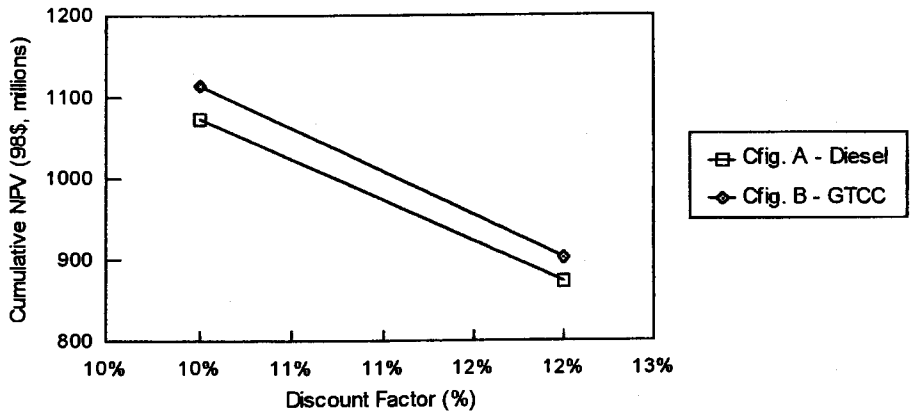
Although a doubling of the cost of energy not served shows a sizable change in the CNPV of costs (roughly US$20 million), the scenarios tend to change in unison. A significant change in the cost of energy not served may have slightly changed the optimization solution (timing and perhaps selected technology), but in comparing two given solutions, the impact is insignificant, as shown in Exhibit 4-10.

Exhibit 4-10
Cost of Energy Not Sold Sensitivity



Although the 2% change in the discount factor (from 10% to 12%) does have a significant impact on the CNPV of costs, it does not significantly change the relative position between the two scenarios as shown in Exhibit 4-11. That is, the impact of changing the discount factor is fairly uniform between these two scenarios. The effect would be more pronounced on technologies that had significantly different production costs.

Exhibit 4-11
Discount Factor Sensitivity



4.5 OPTION SELECTION

In determining which resource should be added to the system, consideration needs to be given to both the generation planning results as well as the electric stability analysis (Section 6). The electric stability analysis indicates that a 90 MW will result in load shedding, while the 60 MW unit will not. Judgment suggests that the unit size should be limited to approximately 75 MW.

In the resource optimization process the generation planning exercise has identified the specific resource additions of 60 MW in the year 2001. The specific technology which is favored, however, is dependent upon the price of natural gas.

Since the state of natural gas exploration at the time of this writing remains unproven, it would be presumptuous to make a prediction of the natural gas price and available quantities. Nevertheless, the optimism regarding the ongoing gas explorations would give credence to the realization of a reduced gas price with sufficient quantities to fuel a 60 MW GTCC.

Therefore, we shall proceed with the assumption that natural gas will be found in sufficient quantities to reduce the price from its current level of US$4.81/MMBtu to something less than US$4.00. Thus, we recommend the addition of a 60 MW class GTCC for operation in the year 2001 for further consideration and for the development of a conceptual design.

The gas turbine combined cycle also has several advantages over the diesel scenario. First the gas turbine would rely on indigenous natural gas as opposed to imported heavy oil. In addition, natural gas is a clean fuel which can be used efficiently and would facilitate financing.

Thus, although the generation planning effort for the high gas price scenario (limited gas supply) indicates the heavy-oil-fired diesel engine as the most economic option, we recommend a liquid fuel-fired gas turbine in view of the environmental and financing issues associated with heavy oil. This rationale is discussed further in Section 9. Should gas not be available, Parsons recommends the exploration of a liquid fuel-fired barge-mounted gas turbine plant option as presented in Section 10.

4.6 GAS TURBINE MODEL SCREENING

A review of the available 50 Hz gas turbines for use in a combined cycle was made by evaluating simple cycle gas turbines in the approximate range of 40 to 60 MW. Exhibit 4-12 presents particular gas turbine models that fall within this range. The upper half of this table, presents gas turbine information at ISO conditions. The lower half of the table presents information on a combined cycle application for the SENELEC system based on an ambient condition at 35°C. The combined cycle information has been developed by Parsons using in-house computer tools.

Exhibit 4-12
50Hz Gas Turbines in 40 to 60 MW Simple Cycle Range

Manufacturer		GE	GE	ABB	RR	Westing-house	ABB	Siemens
Model		PG6561B	LM6000pc	GTX100	Trent	251B11	GT8C	V64.3
Gas Turbine Data[a]								
ISO Base Rating	MWe	41.4	42.7	43.0	50.3	50.3	52.6	62.3
Year Introduced		1996	1997	1998	1996	1982	1994	1990
Frame Machine		Frame	Aero	Frame	Aero	Frame	Frame	Frame
PR		12.2	29.1	20.0	35.0	15.3	15.7	16.1
TIT at ISO	F	2,035	2,300	2,350	2,280	2,100	2,142	2,350
TET at ISO	F	985	846	1,015	798	965	963	988
Efficiency	%	32.9	41.1	37.0	40.6	32.9	34.2	35.2
Combined Cycle Data[b]								
Net Power, new	MWe	51.1	40.7	50.1	49.2	60.8	62.8	75.5
Net Efficiency, new	%	45.7	48.6	49.3	47.7	44.8	46.2	47.6

Notes: a. The gas turbine information is listed at ISO conditions, and is sorted by power.
b. The combined cycle information has been developed by Parsons on the basis of: 35°C (95°F), 60% relative humidity, 60 m elevation, dual pressure non-reheat steam turbine, steam temperature of 850 psig, steam temperature set to gas turbine exhaust minus 50°F, a wet dry cooling tower, condenser back pressure of 2 psia, high pressure, and no air pre-cooling.

Based upon the need for approximately 60 to75 MWe, the largest three Frame turbines in the above table were selected for additional review. Major combined cycle equipment was designed, costs estimated[2], and part load performance was developed for conditions representative of Dakar. The following Exhibit 4-13 presents selected information for the average ambient condition of 25°C and 60% relative humidity. A example full load heat balance for the ABB GT8C based combined cycle is presented in Appendix C for the conditions referenced in this exhibit.

Exhibit 4-13
Three Likely GTCC Resources Evaluated at 25°C

Manufacturer		Westinghouse	ABB	Siemens
Model		**251B11**	**GT8C**	**V64.3**
Combined Cycle Cost Data				
Capital Cost	$, 10^6	57.8	62.7	68.8
Capital Cost	$/kW	887	918	860
100% Load Point- GTCC				
Net Power, new	MWe	65.2	68.3	80.0
Net Efficiency, new	%	45.6	47.4	48.2
Net Power, degraded 3%	MWe	63.2	66.2	77.6
Net Efficiency, degraded 2%	%	44.8	46.5	47.2
75% Load Point- GTCC				
Net Power, new	MWe	48.9	51.2	60.0
Net Efficiency, new	%	42.9	44.6	45.6
Net Power, degraded 3%	MWe	47.4	49.7	58.2
Net Efficiency, degraded 2%	%	42.1	43.7	44.7
50% Load Point- GTCC				
Net Power, new	MWe	32.6	34.1	40.0
Net Efficiency, new	%	38.6	38.8	40.5
Net Power, degraded 3%	MWe	31.6	33.1	38.8
Net Efficiency, degraded 2%	%	37.8	38.0	39.7
Annual Fuel Consumption				
Fuel Usage @ 80% CF	10^6 m^3/yr	109	110	126

Notes: 1. The combined cycle information has been developed by Parsons on the basis of: 25C (77F), 60% relative humidity, 60 m elevation, dual pressure non-reheat steam turbine, steam temperature of 850 psig, steam temperature set to gas turbine exhaust minus 50°F, a wet dry cooling tower, condenser back pressure of 1.5 psia, high pressure, and no air pre-cooling.

[2] The capital cost estimates are budgetary cost estimates (+/- 30%), produced with automated software. For example, as an input to this budgetary capital cost estimate, the combustion turbine price is based on budgetary prices listed in the Gas Turbine World 1997-98 Handbook. No effort was made to reconcile this estimate to the subsequent and more detailed estimate prepared for the Section 8 conceptual design effort.

Of these turbines, the Westinghouse 251B11 and the ABB GT8C are most closely aligned with the 60 to 75 MW target unit. Based upon the electric systems studies, the Siemens V64.3 is more likely to create a system reliability problem due to its larger size. Comparing the W251 and the GT8C machines, it is clear that the GT8C is a more efficient machine (47.4% vs. 45.6%) with a slightly higher specific cost ($918/kW vs. $887/kW). Although with the current level of cost estimate (±30%), the 4% difference in specific cost is insignificant. The 68.3 MW GT8C base combined cycle is slightly larger than the 65.2 MW W251.

Both of these units have significant potential to be effectively utilized in the SENELEC system expansion plan. As such, both vendors were contacted for performance, budgetary cost estimates and additional support information. Westinghouse (now Siemens Westinghouse) responded with a budgetary cost estimate. The vendor replies are presented in Appendix D.

During the initial communication with ABB, it was learned that the GT8C machine has just recently been upgraded to the GT8C2 which now utilizes "cleaner" annular combustors, and has been uprated from 52.6 to 57.2 MWe. Assuming a similarly designed combined cycle, the GTCC output would increase from approximately 68.3 to 74.3 MWe at 25°C. Both machines are available from ABB.

It is our recommendation that the conceptual design effort for this study proceed with the ABB GT8C. It should be emphasized that SENELEC will make the final model selection following a competitive bidding process of all viable machines. The conceptual design information will however, be fairly independent of the specific machine.

SECTION 5: ELECTRIC SYSTEM STUDIES

This section summarizes the electric system analyses performed. These studies include a load flow analysis, and electric transient stability analysis. The results of these studies are used to provide guidance on the size of unit suited to the system requirements.

5.1 LOAD FLOW ANALYSIS

This section summarizes the findings relative to the location of the two 60 MW generating units that the SENELEC system requires prior to the installation of the Manantali hydro plant. The system considered was the Interconnected Network (RI) including the Kaolack region. The load condition investigated was a load of 245 MW, representing the expected peak in the year 2002. The basic information used to model the system was taken from the provisional report Generation and Transmission Master Plan[1] dated April 1997, supplemented by information from the 1996 report titled Forecasting long Term Demand for Electricity in Senegal (1996 - 2010)[2], the 1995 report titled Feasibility Study on Development of Electric Power System in Dakar Area[3], and the 1994 report titled Medium and Long Term Equipment Program for Electrical Production on the Interconnected Network[4], in addition to discussions with E. H. Malick Diallo in the offices of Parsons in Reading, PA, USA in December 1997.

Four different generation dispatches were studied, both with the 90 kV bus tie of the Cap des Biches station open and closed. The studies were made with the new 60 MW combined cycle units installed at Tobene and alternately at a new site at Kayar, for a total of 16 different runs. The nomenclature used to identify the runs is illustrated in the following example, PK2_1-IA.

PK2_ designates the peak load condition of the year 2002,
1- designates the installation of the units at Tobene
1A designates dispatch condition (1) with the bus tie open, and
1B designates dispatch condition (1) with the bus tie closed.

Exhibit 5-1 summarizes the 16 different runs. Exhibit 5-2 presents the four generation dispatch scenarios. The detailed results on this effort, the load flow analysis printouts and 1-line diagrams have been issued

under separate cover[5] because of the voluminous nature of this information.

Exhibit 5-1
Load Flow Case Legend

Run		Site		Dispatch				Bus Condition	
No.	ID	Tobene	Kayar	1	2	3	4	Open	Closed
Tobene									
1	PK2_1-1A	✓		✓				✓	
2	PK2_1-1B	✓		✓					✓
3	PK2_1-2A	✓			✓			✓	
4	PK2_1-2B	✓			✓				✓
5	PK2_1-3A	✓				✓		✓	
6	PK2_1-3B	✓				✓			✓
7	PK2_1-4A	✓					✓	✓	
8	PK2_1-4B	✓					✓		✓
Kayar									
9	PK2_2-1A		✓	✓				✓	
10	PK2_2-1B		✓	✓					✓
11	PK2_2-2A		✓		✓			✓	
12	PK2_2-2B		✓		✓				✓
13	PK2_2-3A		✓			✓		✓	
14	PK2_2-3B		✓			✓			✓
15	PK2_2-4A		✓				✓	✓	
16	PK2_2-4B		✓				✓		✓

In developing the Kayar generating site, it has been assumed that the 90 kV line between Cap des Biches and Tobene which is constructed for 225 kV operation is looped in and out of the Kayar bus. This assumption was made on the basis that, as the generating station at Kayar is developed in the future to take advantage of the nearby gas field, the higher transmission voltage will be required. If this is a valid assumption, the step-up transformers of the Kayar generators must anticipate the change to the higher transmission voltage in the near future.

There appears to be no appreciable disadvantage from a system stand point of developing the Kayar generating site. The system also seems to operate equally well with the Cap des Biches bus tie open or closed provided that the generating units of Cap des Biches are properly balanced on the two busses.

Exhibit 5-2
SENELEC Pre-Manantali Load Dispatch
Interconnected Network (RI) (with Kaolack) for the 60 MW Unit

			Dispatch -1			Dispatch-2			Dispatch-3			Dispatch-4		
Unit	Bus	Cap. MW	Com't MW	Disp. MW	Res. MW	Com't MW	Disp. MW	Res. MW	Com't MW	Disp. MW	Res. MW	Com't MW	Disp. MW	Res. MW
Hydro		66												
New 1	15	60	60	45	15	60	50	10	60	50	10	60	50	10
New 2 (60)	16	60	60	45	15	60	55	5	60	55	5	60	55	5
New 2 (90)	4	60												
Cap des Biches														
BOOT	46	50	50	45	5				50	25	25	50	25	25
G301	27	28	28	23	4.5	28	24	3.5				28	22	5.5
G302	25	30	30	24	6	30	27	3						
G303	333	30	30	27	3	30	26	4	30	28	2	30	28	2
G401	11	18				18	17	1	18	17	1	18	17	1
G402	12	18	18	16	2	18	17	1	18	17	1			
G403	14	22	22	20	2	22	20	2	22	20	2	22	20	2
TAG 1	26	15												
TAG 2	2	19												
TAG 3	3	23												
Bel Air														
G101	50	12										12	12	
G102	50	12										12	12	
G103	50	12												
G104	50	12												
G105	50	5				5	4.5	0.5	5	4.5	0.5	5	4	
G106	50	5				5	4.5	0.5	5	4.5	0.5			
Kaolack 1	35	3.5							3.5	2	1.5			
Kaolack 2	36	3.5							3.5	2	1.5			
Total		577	298	245	53	276	245	31	275	245	30	297	245	52

Expected Peak Demand = 245 MW

5.2 TRANSIENT STABILITY ANALYSIS

This section summarizes the findings relative to the size of the generating unit that the SENELEC interconnected system is able to support. The system considered was the Interconnected Network (RI) including the Kaolack region, a system load of 245 MW including losses was used, the forecast peak load in year 2002. This year was chosen as a year representing the conditions before the generation from Manantali and its 225 kV transmission is available. This analysis addresses the question: What is the proper size of the installed combined cycle plant that can provide needed capacity to meet system

loads until the Manantali hydro is available? Two unit sizes were investigated: 60 MW net and 90 MW net.

The studies were carried out by means of a transient stability analysis of the conditions obtained upon the loss of the combined cycle unit while carrying load. The question addressed was whether the system can sustain the loss of a major unit and still maintain proper frequency and voltage, and the answer is dependent, in large measure, upon the amount of available unused capacity in the units that are on-line. This unused capacity is known as the "spinning reserve." If the amount of spinning reserve is greater than the amount of capacity lost in an incident, the capacity lost will be redistributed among the remaining units and the system will maintain its rated frequency. If the capacity lost is greater than the capacity available, the system frequency and voltage will decrease until an equilibrium is reached. If the frequency falls low enough, automatic load shedding will occur in an attempt to bring the load and generation back into balance. Any operation at reduced frequency or the shedding of customer load is to be avoided if the quality of service is to be maintained.

In order to analyze the SENELEC system, three scenarios of unit commitment to meet the expected load were studied:

1. The first scenario makes the assumption that units will be loaded to no more than 90% of their maximum capability, a spinning reserve of 10%.
2. The second assumes a maximum unit loading of 85%, a spinning reserve of 15%, and
3. The third assumes a maximum unit load of 80% capacity and a spinning reserve of 20%.

Exhibit 5-3 presents the assumed unit commitment and loading for the three reserve levels with a 60 MW unit. Exhibit 5-4 shows the unit commitment and loading with a 90 MW unit, and Exhibit 5-5 shows the result and frequency deviations resulting from the loss of the largest unit. The installation of the 90 MW unit will cause load shedding, while the smaller unit will not. For this reason, and the higher reliability obtained with the 60 MW unit, the 60 MW class unit is recommended. The indicated trends suggest that a generation unit (for the project) of up to 75 MWe is likely to be acceptable.

Exhibit 5-3
SENELEC Pre-Manantali Load Dispatch
Interconnected Network (RI) (with Kaolack) for the 60 MW Unit

		Case 1 @90% Capacity			Case 2 @85% Capacity			Case 3 @80% Capacity		
Unit	**Unit No.**	**Com't MW**	**Disp. MW**	**Res. MW**	**Com't MW**	**Disp. MW**	**Res. MW**	**Com't MW**	**Disp. MW**	**Res. MW**
Hydro										
New 1	401,2	60	54	6	60	51	9	60	48	12
New 2 (60) New 2 (90)	403,4	60	54	6	60	51	9	60	48	12
BOOT	44, 45	50	45	5	50	43	7	50	40	10
G301 G302 G303	301 302 303	27.5 30 30	24 26 26	3.5 4 4	27.5 30 30	22 24 24	5.5 6 6	27.5 30 30	22 24 24	5.5 6 6
G401 G402 G403	41 42 43	18	16	2	18 18	15 15	3 3	18 18 22	12 12 15	6 6 7
TAG 1 TAG 2 TAG 3										
G101 G102 G103 G104										
G105 G106										
Kaolack 1 Kaolack 2	91 92									
Total		**276**	**245**	**30.5**	**294**	**245**	**28.5**	**316**	**245**	**70.5**

Expected Peak Demand = 245 MW

Exhibit 5-4
SENELEC Pre-Manantali Load Dispatch
Interconnected Network (RI) (with Kaolack) for the 90 MW Unit

		Case 1 @90% Capacity			Case 2 @85% Capacity			Case 3 @80% Capacity		
Unit	Unit No.	Com't MW	Disp. MW	Res. MW	Com't MW	Disp. MW	Res. MW	Com't MW	Disp. MW	Res. MW
Hydro										
New 1	401,2	60	54	6	60	52	8	60	48	12
New 2 (60) New 2 (90)	403,4	90	81	9	90	78	12	90	72	18
BOOT	44, 45	50	45	5	50	44	6	50	40	10
G301 G302 G303	301 302 303	27.5 30 30	24 26 26	3.5 4 4	27.5 30 30	23 24 24	4.5 6 6	27.5 30 30	22 24 24	5.5 6 6
G401 G402 G403	41 42 43							22	15	7
TAG 1 TAG 2 TAG 3										
G101 G102 G103 G104										
G105 G106										
Kaolack 1 Kaolack 2	91 92									
Total		**288**	**256**	**31.5**	**288**	**245**	**42.5**	**310**	**245**	**64.5**

Expected Peak Demand = 245 MW

Exhibit 5-5
SENELEC Pre-Manantali Frequency Response
Interconnected Network (RI) (with Kaolack)

Unit Size MW	Unit -Load MW	Frequency Hz
60	54	49.2
60	51	49.4
60	48	49.6
90	81	47.0
90	78	47.1
90	72	49.1

5.3 CONCLUSIONS

The electric system studies demonstrate that the installation of the 90 MW unit will cause load shedding, while the smaller unit will not. For this reason, and the higher reliability obtained with the smaller 60 MW unit, the 60 MW class unit is recommended over the 90 MW class unit. The indicated trends suggest that a generation unit (for the project) of up to 75 MWe is likely to be acceptable.

The analyses supports the generating site development at either Kayar or Tobene, and that the system can operate equally well with the Cap des Biches bus tie open or closed provided that the generating units of Cap des Biches are properly balanced on the two busses.

5.4 REFERENCES

[1] "Generation and Transmission Master Plan," SENELEC Direction for Innovation, Planning and Equipment, Planning Division, Provisional Report, April 1997.

[2] "Forecasting Long Term Demand for Electricity in Senegal (1996-2010)," SENELEC Department of innovation planning and Equipment, Division of Background Economic Surveys, April 1996.

[3] "Feasibility Study on Development of Electric Power System in Dakar Area," Final Report, October 1995, EPDC International Ltd., Tokyo, Japan.

[4] "Medium and Long Term Equipment Program for Electrical Production on the Interconnected Network," National Electric Corporation (SENELEC), Sub-Department of Logistics, Management and Strategy, Provisional Report, September 1994.

[5] "90 MW Senelec Power Plant Feasibility Study: Load Flow Analysis," transmitted to Mr. Latsoucabe Fall, SENELEC, via letter package from Lynn Rubow, Parsons dated April 21 1998.

SECTION 6: SITE SELECTION

This section summarizes the site selection considerations, analysis, and recommendations. The following sites were originally considered by SENELEC:

- N'diakhirate.
- Tobene,
- M'boro sur mer (on the sea), and

Two additional sites[1] were added during the study for consideration:

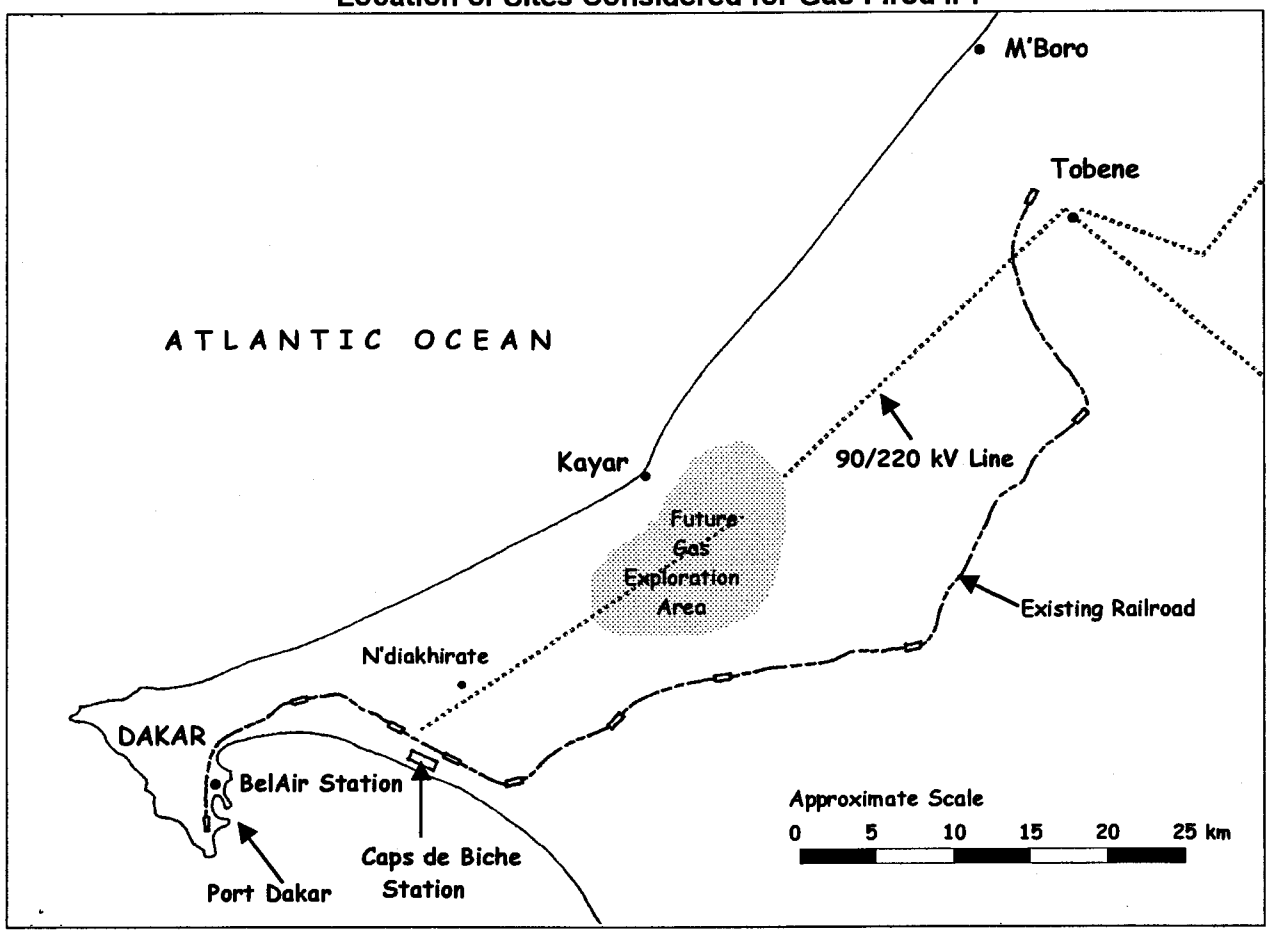
- Bel Air and
- Kayar.

Potential future sites for power generation development are St. Louis and Kaolack areas, which are near population centers, are desired areas for economic growth, and also possess some desirable site characteristics. However, these two sites were eliminated from further consideration due to the long distance from existing and near-term potential natural gas supplies.

The location of considered sites, together with proximity of existing/future natural gas supplies, high voltage lines, railways, and major roads, is presented in Exhibit 6-1.

[1] A third additional site, a barge mooring site near Bel Air was also added later in the study because of the increased likelihood that gas would not be found in sufficient quantities in the near term. This third site is addressed in Section 10, the Barge Mounted Plant Option.

Exhibit 6-1
Location of Sites Considered for Gas-Fired IPP



The following sections describe the site evaluation criteria, assessment methodology, site descriptions, and results.

6.1 CANDIDATE SITE DESCRIPTIONS

Exhibit 6-2 presents key data of each candidate site.

Exhibit 6-2
Key Data for Candidate Sites

	Units	N'diak-hirate	Tobene	M'boro	BelAir	Kayar
Distances[a]						
Dakar Center	km	24	72	82	0	40
Caps de Biches	km	9	58	66	9	30
Existing Major Road	km	0	0.25	5	0	1
Existing Railroad		8	6	12	0.2	18
Existing 90 kV line	km	1	1	15	1	9
Existing/Planned 220 kV line	km	1	1	15	15	8
Nearby Substation?		no	yes	no	yes	no
Existing Gas Line	km	5	52	62	14	19
Existing Gas Well Head		15	52	62	24	19
Likely Areas of Gas Discovery		27	20	29	48	8
Petrosen Discovery (Gadiaga)		17	28	37	38	12
To Shore Point		8	9	0.5	0.5	0.5
Average Ambient Temperature	°C	26.7	25.5	24.3	24.3	24.3
Cooling Water Source		Well[b]	Well[b]	Sea	Sea	Sea

Notes: a. Distances are measured by direct line.
b. Possible overland water pipeline alternative water source.

6.1.1 Common Site Characteristics

Senegal is a flat country, lying in the depression known as the Senegal-Mauritanian Basin. Altitudes of more than about 330 feet are found only at Cap Vert and in the southeast of the country. The country as a whole falls into three structural divisions. These are:

1. Cap Vert, which forms the western extremity and consists of a grouping of small plateaus made of hard rock of volcanic origin;
2. The southeastern and the eastern parts of the country that consist of the fringes of ancient massifs (mountain masses);
3. An immense but shallow basin lying between Cap Vert to the west and the edges of the massif to the east.

Washed by the Canary Current, the Atlantic coast of Senegal is sandy and surf beaten. Like the rest of the country, it is low except for the Presqu'ile du Cap Vert, which represents the westernmost point of the African continent and which shelters Dakar, the finest port in Africa.

All candidate sites are located on Cap Vert, and within 20 km of the northwest Senegal Atlantic coastline.

Climate

The climate of Senegal is divided into two main seasons. The dry season occurs roughly from October through July, and the rest of the year is hot and wet. Dakar averages about 82°F during the wet months.

The Senegalese climate is conditioned by two general factors: first, the tropical latitude and second, the movement of air masses that in turn are governed by anticyclones over the Azores and St. Helena -- regions of high pressure over northern Africa and regions of low pressure near the Equator. The prevailing winds fall into two categories -- those which are dry and those which bring rains.

The dry winds consist of the trade winds -- both from the continent and from the sea -- and the harmattan; they bring no rains at all, apart from a very light precipitation.

From the combination of these various factors, three principal climates may be distinguished, each of them associated with a characteristic type of vegetation.

The coastal (Canarian) climate. This climate occurs along a coastal strip about ten miles wide running from Saint-Louis to Dakar. Its winters are cool with minimum temperatures reaching about 63°F (17°C) in January, and maximum temperatures in May not exceeding 81°F (27°C). The rains begin in June, reach their height in August, and cease in October. The average rainfall is about 20 inches. The M'boro, BelAir, and Kayar sites are in this region, with the Tobene site on the edge of this zone.

The Sahelian climate. This occurs in a zone bounded to the north by the Senegal River and to the south by a line running from Thies (a town on Cap Vert) to Kayes in the neighboring country of Mali. The month of January is very cool, especially in the mornings before sunrise, when the temperature drops to about 57°F (14°C); maximum temperatures rise higher than 95°F (35°C). In May, minimum temperatures do not fall below about 72°F (22°C), while maximums often rise above 104°F (40°C). The dry season is quite distinct, and lasts from November to May. Between July and October the rainfall averages about 14 inches, moderating the temperature somewhat. Maximum temperatures at this

season amount to about 95°F (35°C). The N'diakhirate site is in this region.

Prevailing Winds. The prevailing winds are from the east in the dry season and from the west-northwest in the wet season. With the site on the north-east of the city, prevailing winds will, in general, carry the projected minimum quantities of air pollution inland, but away from the city of Dakar.

Geotechnical Considerations

There is a wide variety of geological/geotechnical features in Senegal. The impact of the various geological/soil conditions on foundations has been mapped out for the Dakar metropolitan area. Such a map, however, has not be developed for the potential sites which are more distant from Dakar: i.e., M'boro, Kayar, N'diak-hirate and Tobene. Nevertheless, the geological features of the candidate sites are not expected to significantly influence the relative costs, and therefore, the selection of the site. The areas under consideration are all seismically inactive.

Basically two types of foundations are used in Senegal: superficial foundations and deep foundations. Superficial foundations are utilized on the better soils with rigid sills or concrete slabs. The deep foundations are utilized on lesser soils like the swell clay and chalky river soils. Deep foundations were utilized for the Cap des Biches power station. Regardless of the site selection, it will be necessary to conduct boring tests and perform a geotechnical study at the site prior to financial commitment. The study will include the following:

- Sampling sections
- Seeping curves
- Depth of Anchorage sills
- Possible compaction
- Test results
- Plate test results with exploitation
- Acceptable constraints, work rate
- Differentiated compaction analysis
- Conclusion

This investigation and a detailed geotechnical report can be prepared in Senegal by CEREEQ for the cost of roughly 10 to 15 million CFA (roughly $6,000 to $9,000).

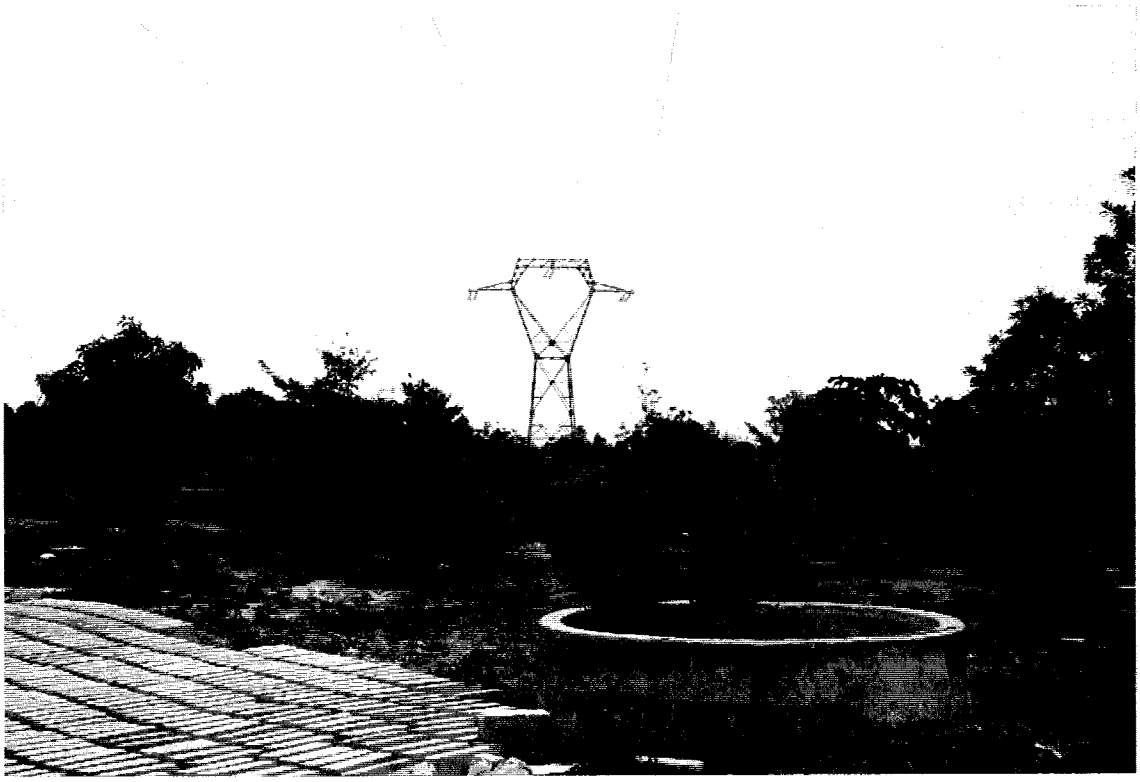
The following sections present a brief description of the individual candidate sites.

6.1.2 N'diakhirate

Senelec owns 1 to 2 hectares property at N'diakhirate which is located directly adjacent to the existing 90 kV line (insulated for 225 kV) that

runs from Caps de Biche to Tobene, as shown in Exhibit 6-3. The site is approximately 24 km east from Dakar, and is located at 14.77 degrees north latitude and 17.23 degrees west longtitude. At one time, it was the intention of Senelec to build a substation here, thus suggesting consideration of the N'diakhirate as a candidate site.

Exhibit 6-3 N'diakhirate Site: View Southwest to Northeast



There are mango and other trees, including several Baobabs, the Senegal national tree. The site is generally open with no existing residential buildings. There is an abandoned building adjacent to the site, and also a new one to the east (Exhibit 6-4), both are thought to be chicken processing buildings, and a small number of other buildings across the road to the west (Exhibit 6-5). Some form of block construction is also going on, shown in Exhibit 6-6, but its nature has not been determined. Some environmental impact assessment has been conducted for this site by EMSI personnel.

Exhibit 6-4 N'diakhirate: View East Showing New Building

Exhibit 6-5 N'diakhirate Site: View West, Across Road to Existing Buildings

Exhibit 6-6 N'diakhirate Site: View North Showing New Construction

6.1.3 Tobene

Tobene is located approximately 72 km northeast from Dakar, and at 15 degrees north latitude and 16.5 degrees west longitude. This site relatively flat, and is adjacent to an existing substation. This substation is the intermediate relay station of existing 225/90 kV transmission lines and the important base connecting Dakar, Thies, Dakal and Taiba. The areas surrounding the proposed site are now farms where mangos, barnyard grasses and other plants are cultivated. This site is about 500 meters from the nearest village.

The Tobene site is located on the northern side of the existing substation and the land is flat. One view looking east, showing the switchyard and east fence is presented in Exhibit 6-7.

Exhibit 6-7 Tobene Site: View East Showing Switchyard

The main road, located within 1 km of Tobene is being resurfaced, and should be adequate to bring equipment, perform construction activities, conduct operations, etc. to the plant site. The connecting road (less than 1 km) between the main road and the switching station would need improvement/resurfacing.

While there is some room within the existing fenced site area, the area would be extended to accommodate comfortable placement of the new combined cycle plant, and space for a second unit.

An existing well of approximately 300 m depth is used to provide water to the site, as shown in Exhibit 6-8, and also to the neighboring village(s), via an existing elevated tank shown in Exhibit 6-9. Two or more deep wells would be required to provide water for the new combined cycle plant, and that a tradeoff between the cost of developing this source, and potential impact on other water sources, against a dry or wet/dry cooling scheme is required.

Exhibit 6-8 Tobene Site: Existing On-Site Well

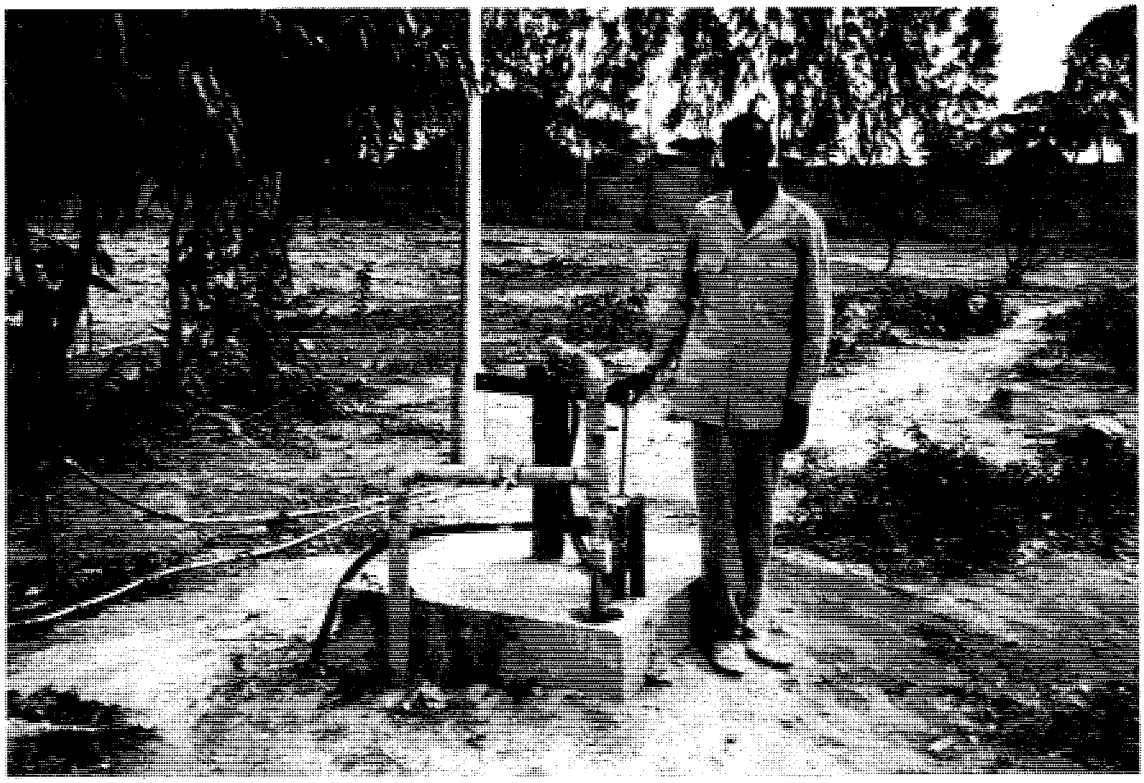


Exhibit 6-9 Tobene Site: Existing Water Tower Outside Station Boundary

Since the Tobene site is located away from the coast, and at the south end of the Sahara Desert, its weather is generally hot and dry, and it separates into the rainy and the dry seasons. The rainy season is from June to October and precipitation concentrates in three months from July to September. Almost no rain falls in the dry season. The highest monthly mean atmospheric temperature is 42°C in August and the lowest one is 14°C in January. The yearly mean relative humidity is around 60 percent and the yearly mean rainfall is about 600 mm. Wind blows from the sea side (a northwest wind) in the dry season and from the inland side (a southeast wind) in the rainy season. The maximum speed of the wind of 24 m/s has been recorded. Thunder mainly occurs in the rainy season and the number of days with thunder is around 26 days on the yearly average. Since this site is near the Sahara Desert, clouds of sand are mainly generated in the dry season, with the average occurrence of about 60 days/y.

According to the boring data which were obtained when the substation was built, the land is sandy with many fine particles and sufficient bearing capacity of soil as a foundation can not be expected. However, according to the penetration test data, a strong load bearing layer which cannot be penetrated can be found 9 to 10 meters below the present ground level[1]. It is therefore suitable to use pile foundations to support important and very heavy machinery, equipment and structures such as turbine foundations of diesel generating plants, and to support them by this layer. Since no ground water is found in the part shallower than 4.2 m below the present ground level, no foundation problems caused by ground water are anticipated.

Tobene is felt to be an excellent site, and the only concern is the adequate supply of cooling water.

6.1.4 M'boro sur mer

The M'boro sur mer site is on the shore, and is approximately 82 km northeast from Dakar, and is located at 15.18 degrees north latitude and 16.91 degrees west longitude. The site accessed by a 5 km very narrow road, in need of some improvement. This may be an issue for construction and operation of the facility. Also, the ocean water at this location is very shallow, and the intake would need to be at least 400 m from shore. From low to high tide, there is about 100m travel of the water's edge. Because of the shallow water, bringing equipment, fuel, etc. to the site by barge would be problematic. Views of the coastline looking Northeast, Southeast and Southwest are presented in Exhibits 6-10 through 6-12.

Exhibit 6-10 M'boro Site: View Looking Northeast

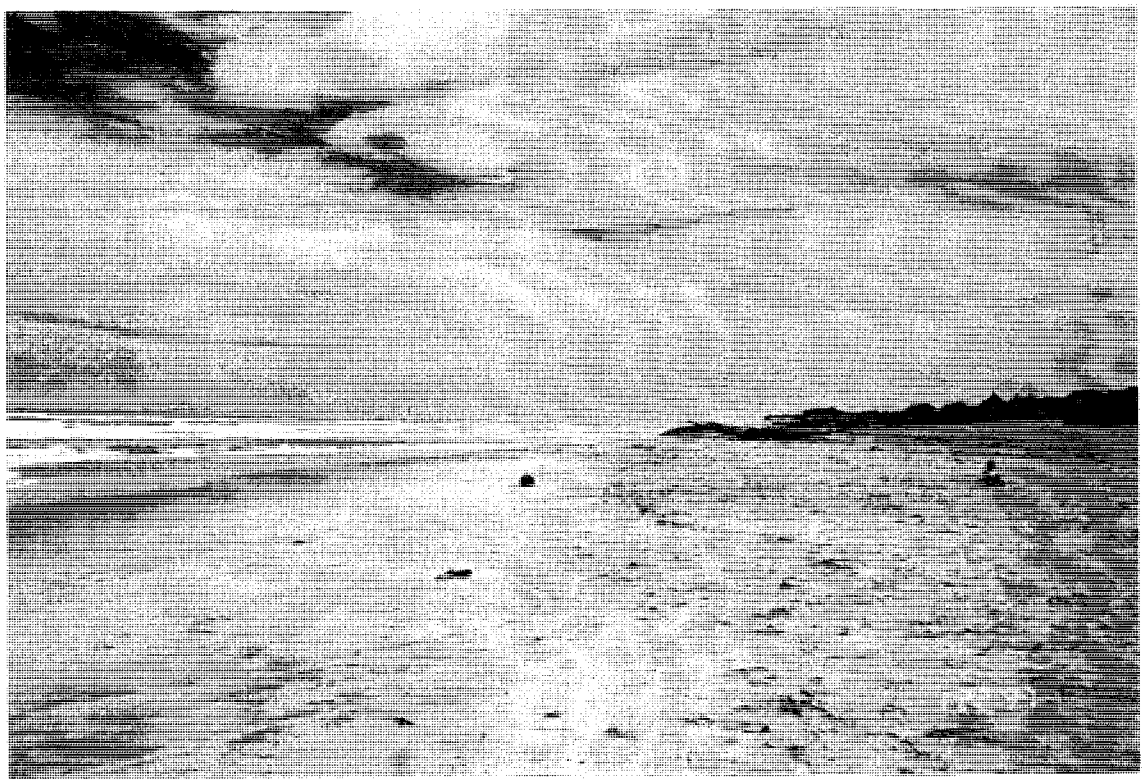


Exhibit 6-11 M'boro Site: View Looking Southeast

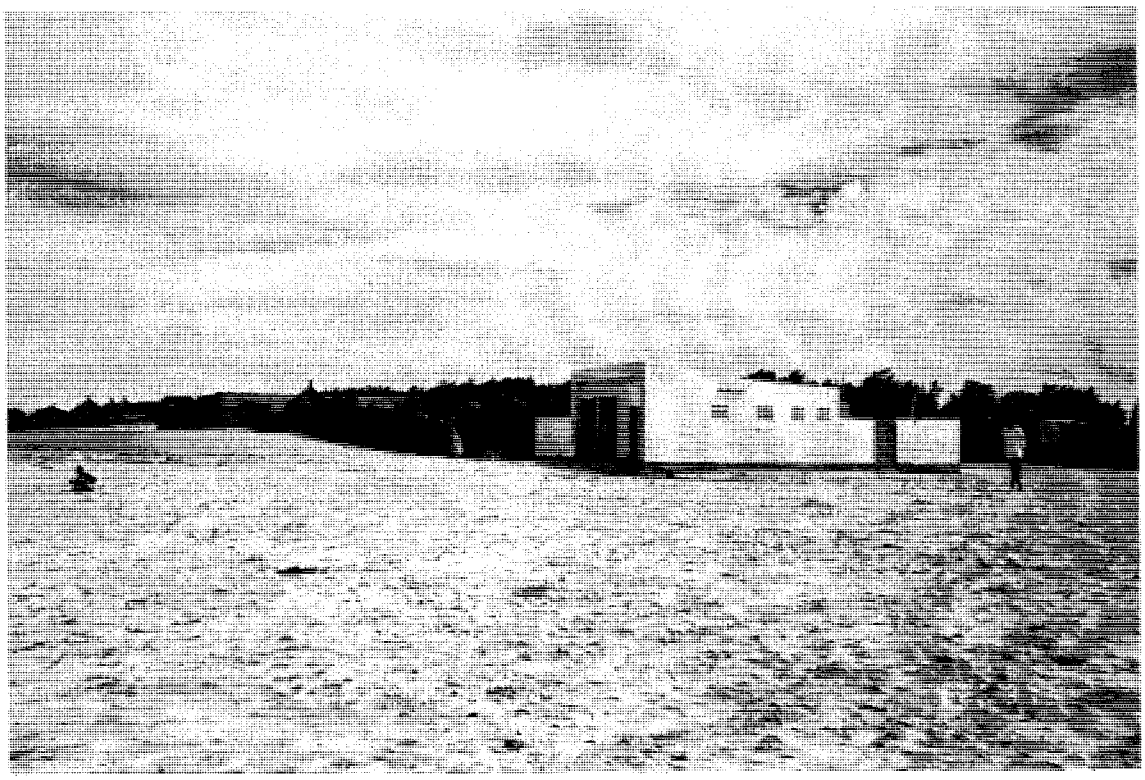
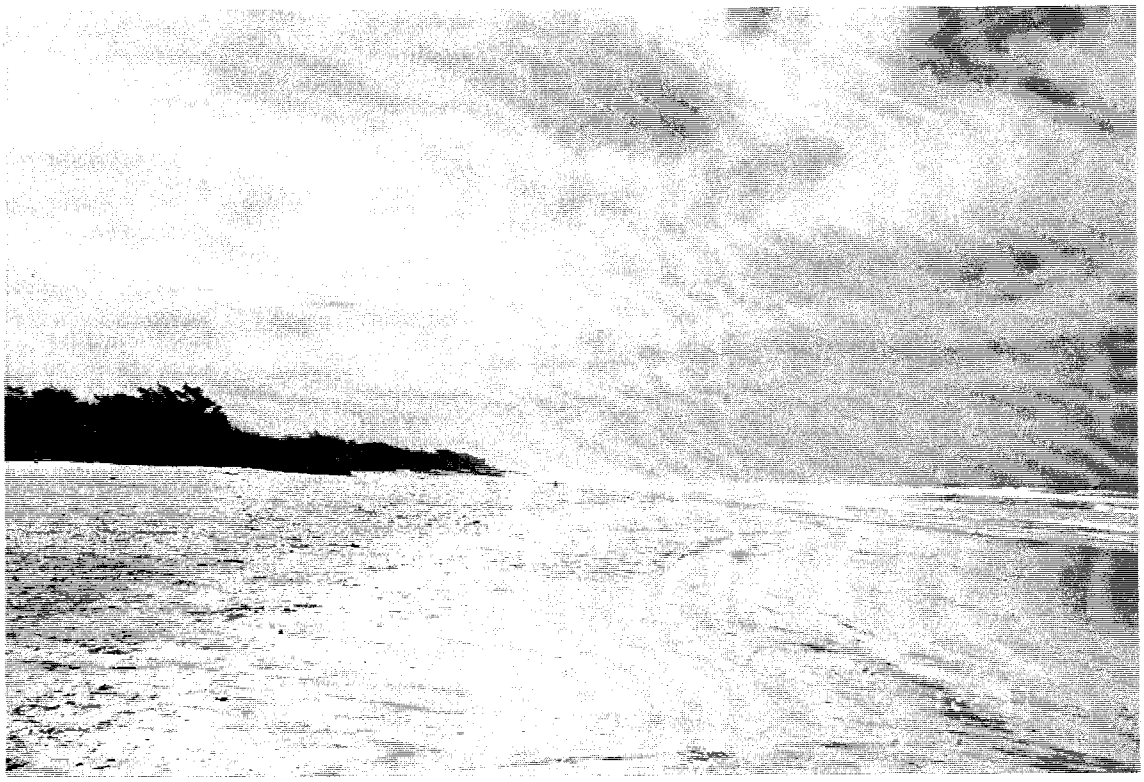


Exhibit 6-12 M'boro Site: View Looking Southwest



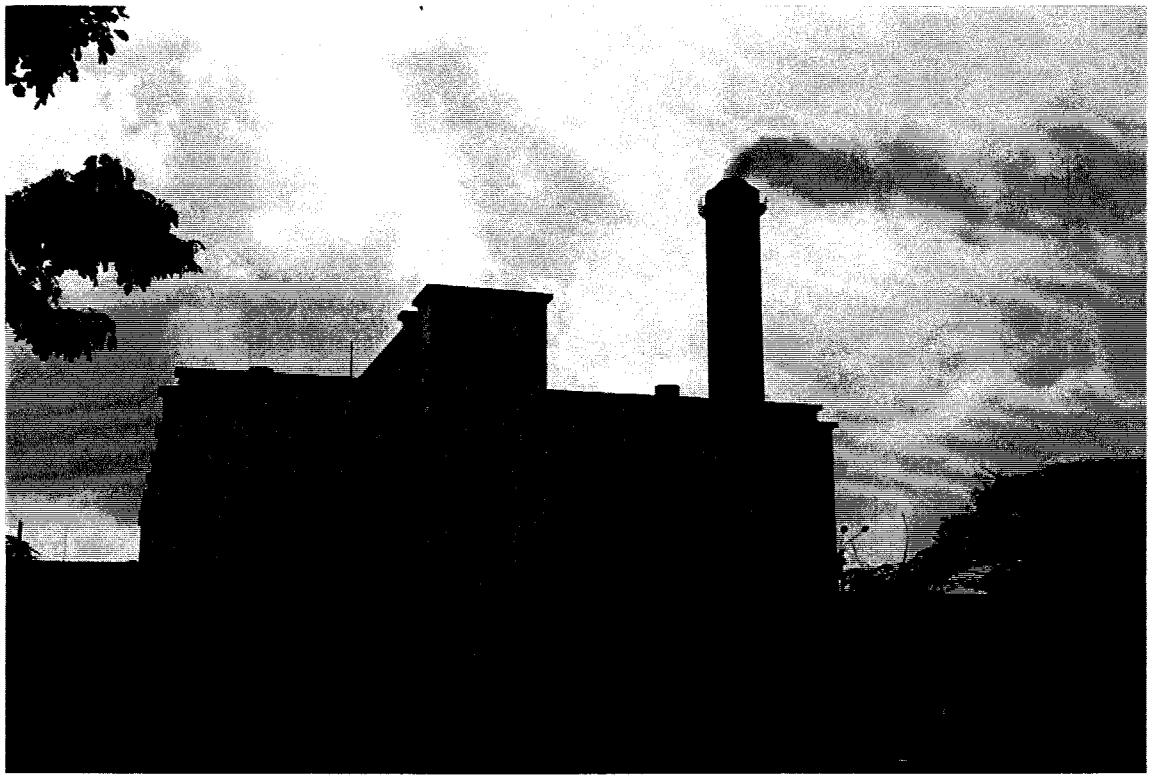
As shown, there are some dwellings along the shore which may have to be relocated, although an area slightly to the south can be found with no dwellings.

M'boro is felt to be an excellent site. Minor concerns include the longer distances to HT lines and the future gas supply.

6.1.5 BelAir

The oldest Senelec plant, BelAir is located on the east side of Dakar, and consists of four small operational, but inefficient, heavy-oil fired boilers/turbines, each 12.8 MW; and several smaller, retired units. A photograph of the main BelAir boiler building is shown in Exhibit 6-13. There is some available space at the BelAir site as some former units have been demolished. A 1990 Japanese funded project provided 2x5 MWe Mitsubishi diesel units in place of the oldest plants. Connections between the Centrale units and the town are controlled here. Control systems are old, with manual data recording. Heavy oil burned here is between 2 and 4 % sulfur. Send out from this plant is 90 kV and 6.6 kV. BelAir has about 200 employees.

Exhibit 6-13 BelAir Site: View of Main Boiler Building



BelAir was considered for the new facility since there is existing infrastructure (including cooling water), and there is sufficient space for locating the new facility. A "clean" gas burning plant would improve the local environment, when compared to the existing heavy-oil fired plants.

The greatest disadvantage of the BelAir site is the long distance from the existing gas line, as well as likely future gas exploration.

6.1.6 Kayar

Kayar is located on the north Atlantic coast, about 40 km from Dakar and, typical of the region, has a flat terrain. Kayar is located at 14.91 degrees north latitude and 17.17 degrees west longitude.

Kayar was selected as a candidate after consideration of existing and future natural gas locations, the likelihood of smaller gas deposits than formerly thought, and further consideration of the difficult water situation at inland sites.

A small contingent from Senelec visited the Kayar site January 9, 1998 to make preliminary observations. This group found no problems with the site, and concluded that it was an attractive site, and warranted further investigation. Subsequent investigations and site visits by EMSI

and Parsons further supported the desirable aspects of developing a new power plant at Kayar.

Three potential sites were identified near Kayar and are indicated on Exhibit 6-14:

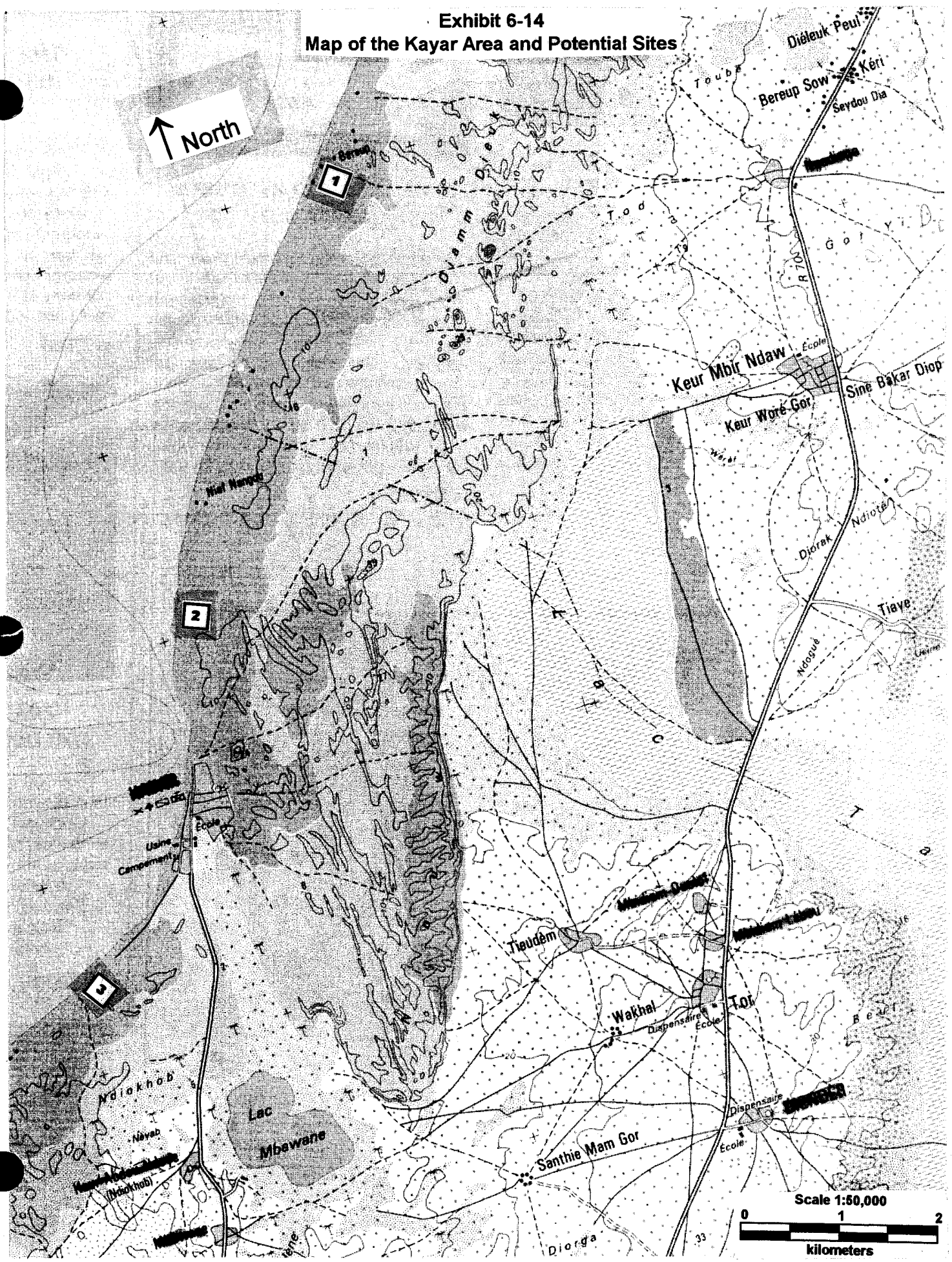
- Kayar-1: located near the Bereup village, 7 km north of Kayar.
- Kayar-2: located between Bereup and Kayar, 2 km north of Kayar
- Kayar-3: located 2 km south of Kayar.

The second Kayar site was found to be the best site. Kayar-1 may be disruptive to the Bereup village and is farther (~700m) from oceans depths (10 m) required for the cooling water intake structure. Kayar-3 is also farther (~1100 m) from the deeper water, while Kayar-2 is relatively close (~300 m) to the 20 m.

Kayar -2 is located in the Thies Region, within the District of Thies and the subdistrict of Pout in the Rural Community of Diender Guedj. The site is approximately 28 km form the high voltage post at Tobene, 7.5 km form the Ngadiaga gas well and 2 km from phone connections at Kayar.

The topography at Kayar-2 is flat and covered by forest. The soil is very permeable sandy soil. Small fresh water wells exist with depths of 3 to 5 meters.

Exhibit 6-14
Map of the Kayar Area and Potential Sites



Several deep wells have been drilled in the vicinity of Kayar and are summarized in Exhibit 6-15. A bore hole with a 300 m^3/h capacity is planned for the town of Kayar.

Exhibit 6-15
Existing Deep Wells Within the Kayar Vicinity

Parameter	Mbirdiam	Diender Ndaw	Ber Tialane	Between Keur Abdou Ndoye and Mbawane
Year of service	1970	1982	1996	1990
Depth, m	180	247	240	250
Flow, m^3/h	300	49	300	100
Static Level, m	27.6	50	48	50

The small town of Kayar has a significant fishing industry which employs many individuals. Two views of the main street within Kayar are presented in Exhibits 6-16 and 6-17. Several views of the fishing industry are presented in Exhibits 6-18 through 6-20. Exhibits 6-21 and 6-22 present two views of the suggested Kayar site.

Exhibit 6-16 Town of Kayar: View Looking North

Exhibit 6-17 Town of Kayar: View Looking South

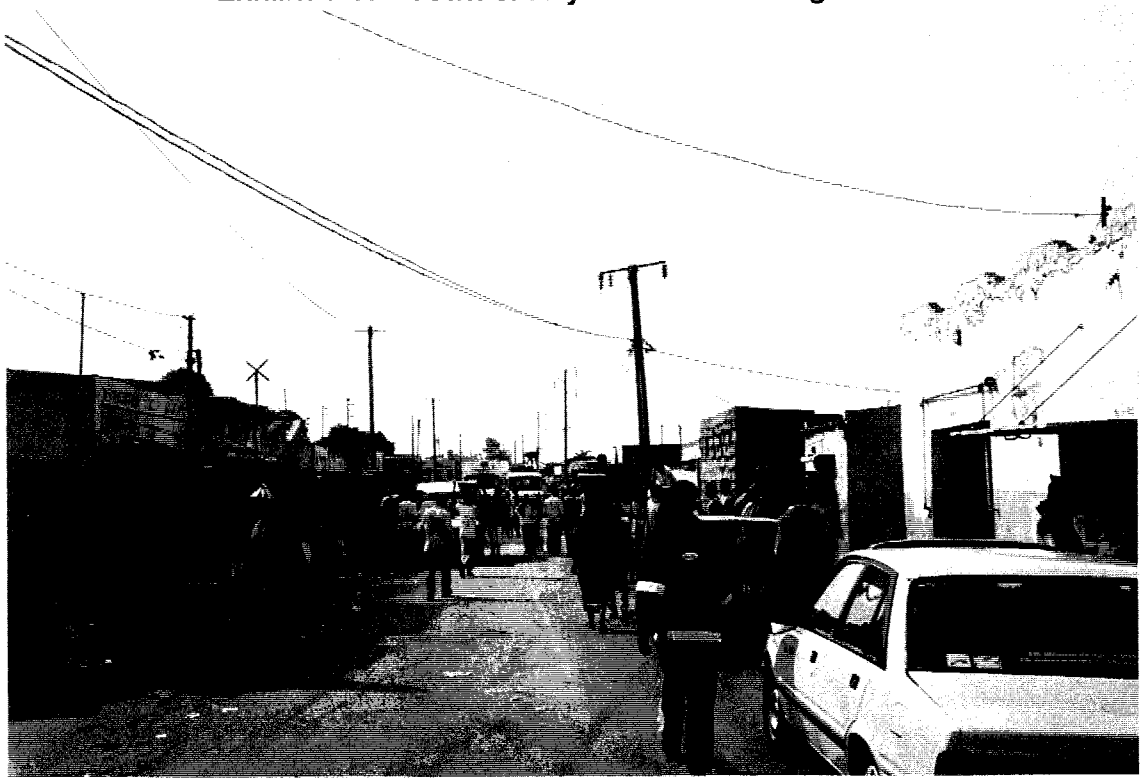


Exhibit 6-18 Kayar Fishing Industry: The Boats

Exhibit 6-19 Kayar Fishing Industry: The Catch

Exhibit 6-20 Kayar Fishing Industry: The Fish Smoking Area

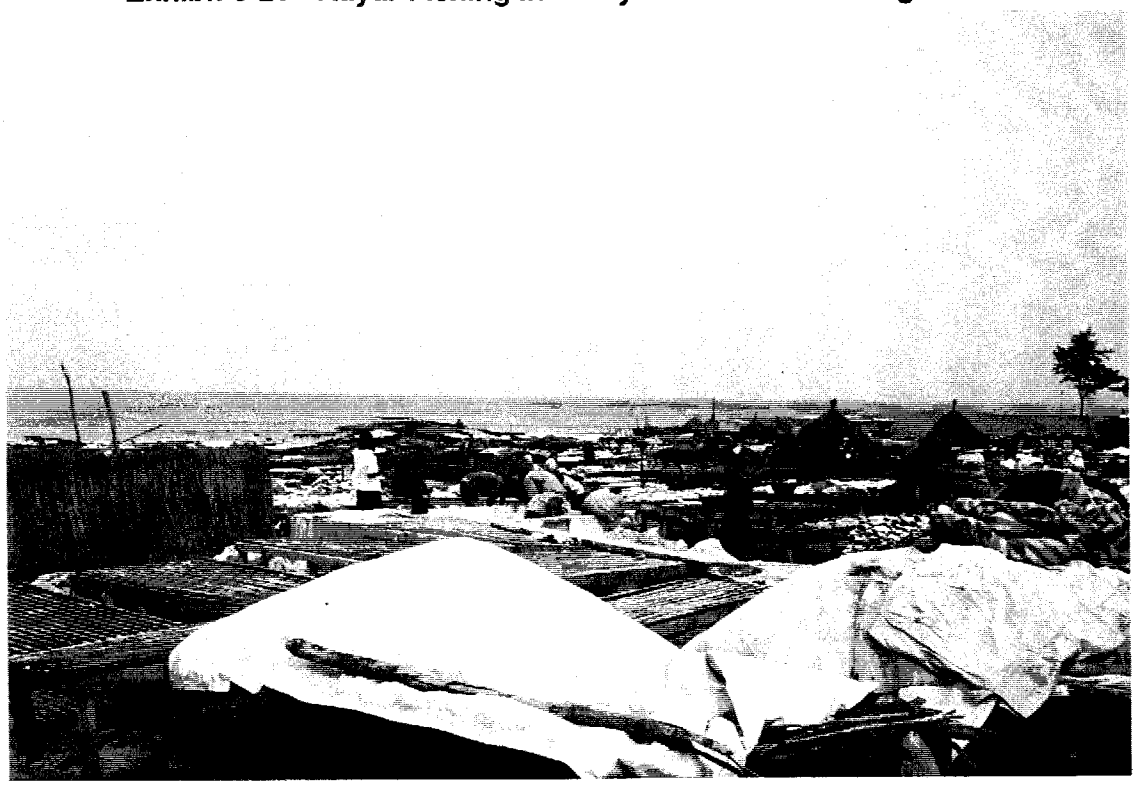


Exhibit 6-21 View of the Kayar Site from the Ocean looking East

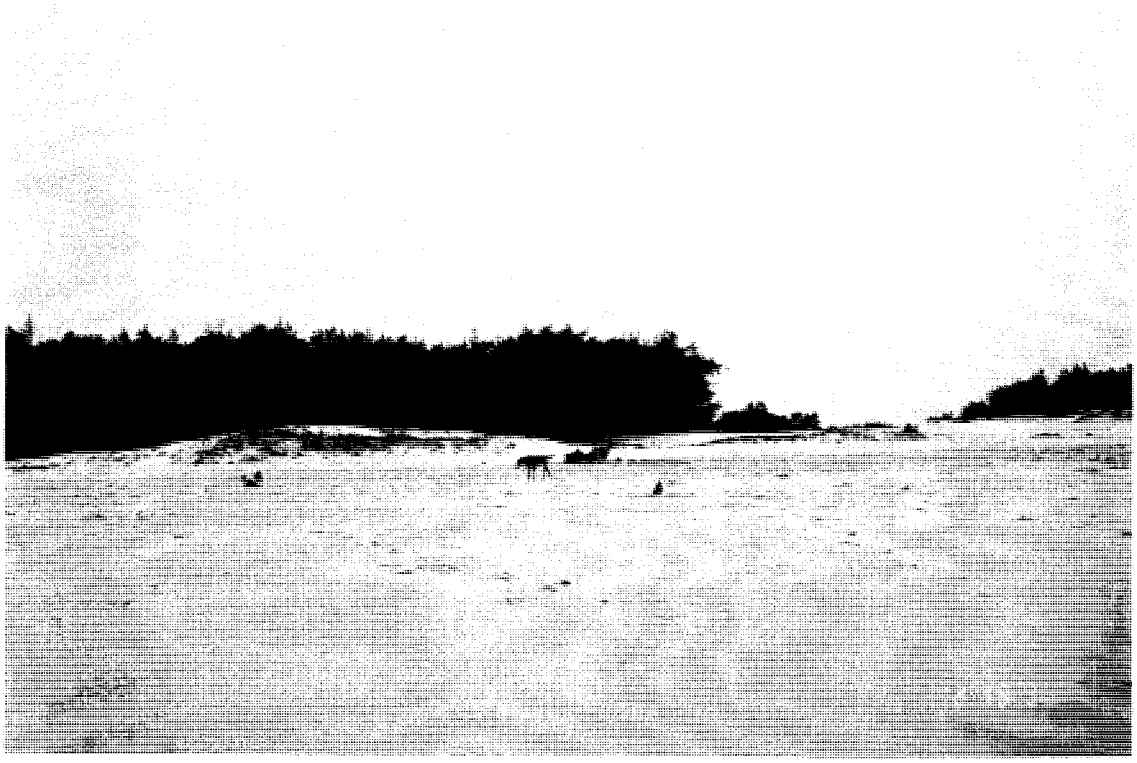


Exhibit 6-22 View of Beach at Kayar Site looking South toward Yoff

6.2 SITE EVALUATION CRITERIA AND METHODOLOGY

The site selection must consider engineering, environmental/permitting, and economic considerations. While all do not apply in Senegal, engineering requirements normally considered in site evaluation are presented in Exhibit 6-23. Many of these criteria were considered in this preliminary analysis; others will be considered beyond this feasibility study as detailed engineering progresses.

Exhibit 6-23
Site Evaluation Criteria

Topic	Detailed Considerations
Earthwork	Site topography Depth to rock Cut and fill requirements
On-site drainage and relocations	Required road relocations Gas well on-site Streams Homes Cemeteries Railroads Transmission lines Wetlands Pipelines
Road Access	Regional access Upgrading required for local roads Bridges required Distance to major highways Local tonnage requirements
Rail access, as required	Length of spur required Condition of tracks Length of tracks required upgrading Is the topography suitable for tracks?
Flooding potential	Flood hazard area, e.g. 100 or 500 year flood Dams above the site Site topography
Site size and number of parcels	Expansion potential Total area available Number of property owners Owner of property or properties Laydown areas available Topography limitations
Ambient Air	Prevailing wind direction Salt spray concentration Sandstorms / Duststorms / Particulates Existing ambient air quality
Water supply potential	Probable sources - ocean, river, lake, wells Municipal wastewater Reliability of sources Water quality

Topic	Detailed Considerations
	Hydraulic considerations Is augmentation required? Is dam required?
Geotechnical characteristics	Foundation types required Limestone area - potential for sinkholes Underground mining? - Potential for subsidence Ground water depth Depth of bedrock Characteristics for site soil and bedrock
Potential for solid waste disposal	Distance from the plant site Topography of site Required access to disposal site Permittability of the site Size of available area Potential for ground water contamination
Transmission considerations, including power, district heating, natural gas and oil lines	Distance to nearest line Environmental considerations for route Size of nearest line Topography for line Property owners along line Geotechnical considerations for line Overhead or buried River crossing required
Seismic considerations	Foundation considerations for Seismic Zone

It is feasible to build the proposed facility at each of the candidate sites. The most important consideration will be the difference in capital and the life-cycle costs projected for each site, considering sensitivity to various possible projected parameters which are less certain. For each site, quantifiable characteristics and differences were assessed and compared.

6.3 SITE EVALUATION

Evaluation of the candidate sites was conducted through qualitative and quantitative assessments.

6.3.1 Qualitative Assessment

Exhibit 6-24 presents the results of a qualitative assessment conducted by the Parsons Team, and supported through conversations with the Senelec staff.

Exhibit 6-24
Qualitative Site Evaluation

	N'diak-hirate	Tobene	M'boro	BelAir	Kayar
Desired location for economic growth	3	3	4	1	4
Generation diversity	4	4	4	2	4
Environmental Impact	3	4	4	3	4
Existing design data	2	3	2	4	3
Proximity to population areas	4	4	4	1	3
Possibility of future expansion	4	4	4	2	4
Site development risk (substructure and relocation considerations)	3	4	4	4	3
Site development cost risk (water availability concerns)	3	3	4	4	4
Site development cost risk (gas availability/development considerations)	4	3	3	2	4
Impact on electric grid stability	2	3	3	4	3
Total Score[a]	3.2	3.5	3.6	2.7	3.6

Note: a. Range of scores is 1 to 5, with 5 being the best score.

Some qualitative parameters can be quantified, as well as other normally quantifiable parameters. Cost and performance was quantified as possible, as presented in the following section.

6.3.2 Quantitative Assessment

The following aspects of the candidate sites were quantified for comparison, considering that the plant would consist of two units for a total of more than 140 MWe, and that certain services for four units are put into place at the time of construction of the first unit:

- Site development differences
- Plant design and performance differences, including:
  - Plant capacity
  - Plant heat rate (efficiency)
  - Cooling system design impacts
- Off-site development, including:
  - Gas Pipeline to Gas Fields
  - Cooling water intake
  - Overland Pipeline
  - Electrical HT Lines
  - Substation/Modifications

- Operating cost differences

Capital cost differences were recognized directly, and the net present value of operating cost differences over a 15 year study period were calculated, resulting in a total net present value used as the figure-of-merit for comparison. Operating cost differences result primarily from variations in plant capacity and performance resulting from (1) average ambient temperature differences at shore and inland plants, and (2) efficiency differences resulting from ambient temperature, and also cooling configuration wet-dry cooling tower vs. direct ocean water cooling.

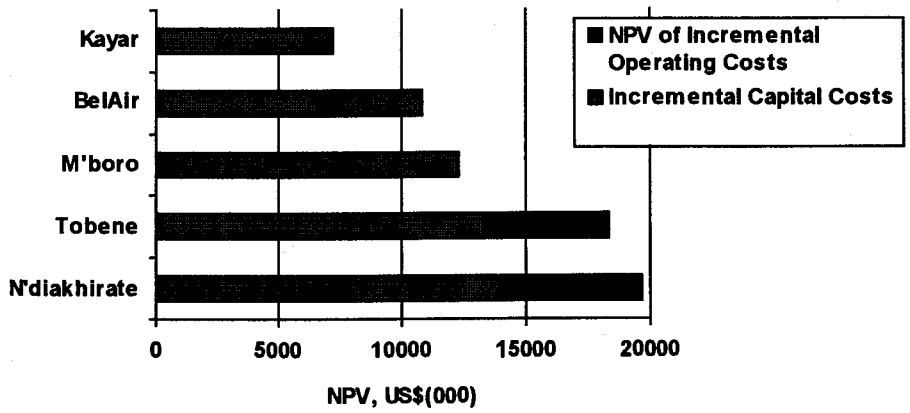
The results of the assessment are presented in Exhibit 6-25.

Exhibit 6-25
Quantitative Site Evaluation

Component	1998 US$(000)				
	N'diak-hirate	Tobene	M'boro	BelAir	Kayar
Site Development	$1,535	$1,485	$1,742	$603	$1,117
Plant Differences	$3,223	$3,223	$1,028	$1,028	$1,028
Off-Site Development Projects	$5,820	$5,960	$9,559	$9,190	$5,089
Capacity Penalty	$3,378	$2,632	$0	$0	$0
Total Incremental Capital Cost	$13,956	$13,300	$12,329	$10,821	$7,234
NPV of Operating Costs, 15 years	$5,745	$5,077	$0	$0	$0
Total Incremental NPV of costs	**$19,701**	**$18,377**	**$12,329**	**$10,821**	**$7,234**

The total incremental Net Present Value of each site is depicted graphically in Exhibit 6-26.

Exhibit 6-26
Quantitative Site Evaluation: Incremental Net Present Value



Exhibits 6-25 and Exhibit 6-26 show that the Kayar site is preferred over the second choice, BelAir. By locating the plant on the sea, and close to existing and future gas development, the Kayar site has the best chance of achieving the lowest cost.

It is noted that if the requirement to account for any future gas development is removed, the BelAir site becomes the best choice. This is also discussed further in the study of an alternative barge-mounted plant in Section 10.

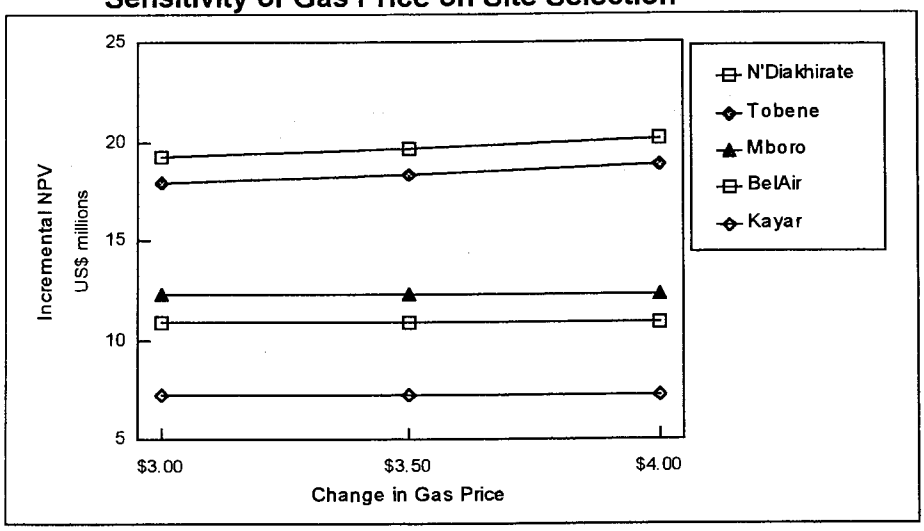
6.3.3 Sensitivity Analyses

Three sensitivity analyses were performed, including:

- Impact of natural gas price,
- Impact of natural gas development, and
- Impact of electric system development.

Natural gas price affects the impact of plant efficiency differences. A range of price from US$3.00 to US$4.00 were investigated. US$3.50 was the nominal assumed price. The results shown in Exhibit 6-27 demonstrate that the selection of site would not be influenced by the price of natural gas.

Exhibit 6-27
Sensitivity of Gas Price on Site Selection



Two categories of off-site construction include construction of a natural gas pipeline and electrical interties to the HT transmission line. Exhibit 6-28 shows the influence of a change in the gas "project" cost, and demonstrates that as this cost increases, the Kayar site becomes more attractive.

Exhibit 6-28
Influence of Off-Site Gas "Project" Costs on Site Selection

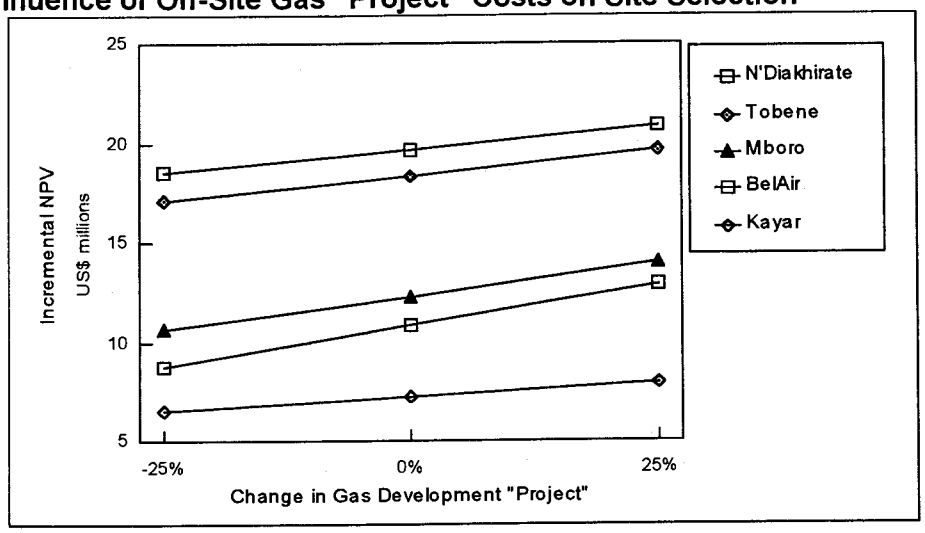
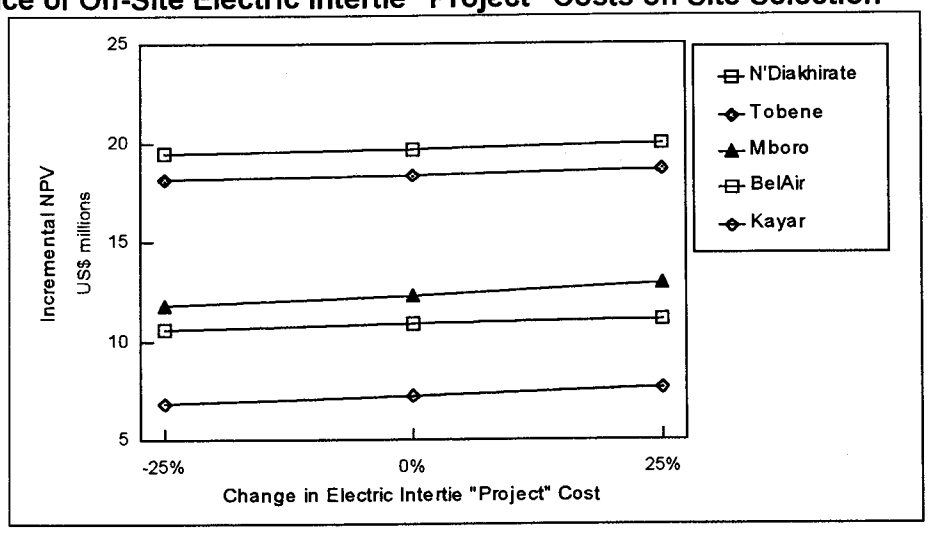


Exhibit 6-29 shows the influence of a change in the electric intertie "project" cost, and demonstrates that that there is very little influence on site.

Exhibit 6-29
Influence of Off-Site Electric Intertie "Project" Costs on Site Selection



6.4 SITE RECOMMENDATION

Based on the results of the qualitative and quantitative analyses, it is clear, pending additional investigation and any forthcoming surprises, that the Kayar site should be selected. Kayar is

- close to the new and future gas exploration,
- does not significantly impact groundwater sources,

- fosters high plant efficiency, and
- potentially results in the least overall capital and operating cost of candidate sites.

The recommended site to serve as a backup to Kayar is M'boro. While the BelAir site scored high on the quantitative analysis, it is not preferred for more qualitative reasons, including the proximity to existing populated areas, and the distance to the expected areas of gas development. When gas supplies are better defined, and existing units are retired, BelAir may be an excellent candidate site for the next SENELEC generating station.

While Tobene is a favored site with regard to location, it is more costly than the seaside sites due to its lower capacity and efficiency, and presents a risk with regard to cooling water supply.

It is noted that if the requirement to account for any future gas development is removed, the BelAir site becomes the best choice. This is also discussed further in the study of an alternative barge-mounted plant in Section 10.

6.5 REFERENCES

1. Prefeasibility Study on Project for Construction of Diesel Power Plant at Tobene, EPDC, March 1993, p 5-8 to 5-10.

SECTION 7: ENVIRONMENTAL ASSESSMENT

The following environmental information may prove useful in the preparation of an environmental assessment, which may be required as the project moves forward. This information, as presented below, is not an environmental assessment.

The purpose of this environmental information section is to provide a brief description of the project, as it relates to the site environment, and to address potential environmental issues as identified to date. Knowledge of the existing environment is limited. Based on the Scope of Work for this project the environmental issues to be addressed are as follows:

- Assessment of air pollution impact under normal and worst case operating condition.
- Assessment of the impact of facility operation and construction on surface and groundwater including a description of recommended mitigation measures.
- Assessment of the impact of the facility on habitat, endangered species, archaeological historic and cultural resources.

The major project alternatives considered in the feasibility study are presented in Section 3: Potential Fuel Sources, Section 4: Selection of Preferred Generating Option, and Section 6: Site Selection.

7.1 AFFECTED ENVIRONMENT

The core environmental law in Senegal is the "Code of the Environment" (83-05) which sets out conditions for the operation of Class 1 and Class 2 developments (Title I); control of water pollution (Title II); control of air pollution (Title III); and noise (Title IV). Power plants are included as industrial facilities in the Class 1 developments which are defined as those requiring siting away from areas of human habitation, surface water bodies, the sea and transport infrastructure. Enabling regulations for implementation of the Code have not been passed. Therefore, there are no existing national pollutant emission standards or ambient environmental quality standards applicable to the project.

The following describes the environmental impacts that are expected to result from the operation of the proposed cogeneration facility.

7.1.1 Air Pollution Impacts

Emission Standards

At present, no air emission standards have been passed in Senegal. As guidance, the World Bank's maximum emission levels for new thermal power plants are summarized. These guidelines set forth maximum emission levels for fossil-fuel based thermal power plants of 50 MWe or larger using fuel oil, or natural gas.

The maximum emission levels given here can be consistently achieved by well-designed, well-operated and well-maintained pollution control systems. The maximum emission levels are expressed as concentrations to facilitate monitoring. Dilution of air emissions to achieve these concentration requirements is unacceptable. All of the maximum emission levels should be achieved at least 95 percent of the time that the plant or unit is operating, averaged annually.

- **Particulate Matter (PM)**: For all plants or units, PM emissions (all sizes) should not exceed 50 milligram per normal cubic meter (mg/Nm^3). (A Nm^3 is measured at 1 atmosphere and 0°C.) Alternatively, removal efficiency should be 99.9 percent if 50 mg/Nm^3 is not achievable.

- **Nitrogen Oxides (NOx)**: The specific emission limits are: 460 mg/Nm^3 (130 nanograms per Joule (ng/J) or 225 parts per million (ppm) dry at 3 percent oxygen) for an oil fired power plant; and 320 mg/Nm^3 (86 ng/J or 155 ppm dry at 3 percent oxygen) for a gas fired power plant. Assumptions - Oil: assumes 280 normal cubic meter per gigaJoule (Nm^3/GJ); Gas: assumes 270 Nm^3/GJ.

  For combined cycle units, the maximum NOx emission level is 86 ng/J (or 50 ppm dry at 15 percent oxygen) for gas and 130 ng/J (or 76 ppm dry at 15 percent oxygen) for oil (except diesel). Where nitrogen content of the fuel is greater than 0.015 percent, a NOx emission allowance can be computed based on the following:

Nitrogen content (percent by weight)	Correction Factor (NOx percent by volume)
0.015 to 0.1	0.04 N
0.1 to 0.25	0.004 + 0.0067 (N - 0.1)
>0.25	0.005

- **Sulfur Dioxide (SO_2)**: The total SO_2 emissions from the power plant should be less than 0.20 metric tonnes (t) per day per MWe of capacity for the first 1000 MWe plus 0.10 t per day for each additional MWe of capacity over 1000 MWe (the maximum emissions for any given plant are subject to the findings of the Environmental Assessment). The concentration of SO_2 in flue gas should not exceed 2000 mg/Nm^3, with a maximum emission level of 500 metric tonnes per day. Construction of two or more separate plants in the same airshed to circumvent this cap is not acceptable.

Emissions Overview

All emission data presented are preliminary and will be subject to possible change pending Vendor selection. Vendor-provided guaranteed emission rates will need to be within the allowable emission standards for the facility.

Annual stack emissions for the studied options were developed for SO_2, NOx, CO and particulate emissions. A typical summary of key emissions estimates are presented in Exhibit 7-1.

Exhibit 7-1
Key Emission Estimates for a 60 MW Class Combustion Turbine

Case / Parameter	SO_2	NOx	Part.	CO
Simple Cycle, Gas-fired[a]	Neg. Neg.	86 ng/J 0.973 kg/MW-h	Neg. Neg.	96 ng/J 1.09 kg/MW-h
Simple Cycle, Oil-fired[a]	80.8 ng/J 0.915 kg/MW-h	130 ng/J 1.47 kg/MW-h	11.2 ng/J 0.127 kg/MW-h	101 ng/J 1.14 kg/MW-h
Combined Cycle, Gas-fired[b]	Neg. Neg.	86 ng/J 0.817 kg/MW-h	Neg. Neg.	96 ng/J 0.912 kg/MW-h
Combined Cycle, Oil-fired[b]	80.8 ng/J 0.768 kg/MW-h	130 ng/J 0.1.24 kg/MW-h	11.2 ng/J 0.106 kg/MW-h	101 ng/J 0.960 kg/MW-h

a - Assumes an average heat rate of 11,318 kJ/kW-hr
b - Assumes an average heat rate of 9,500 kJ/kW-hr

Air Pollution By SENELEC

No ambient monitoring data was available at any of the proposed sites to enable comparison of existing air quality levels with ambient standards.

Net air pollution reductions will be estimated based on a comparison of actual emissions from the existing facility and predicted emissions from the replacement facility.

Existing air quality is a result of pollutant emissions from the major power generation plants of SENELEC located in the Dakar area and

many other industrial and distributed boilers within the region. Major SENELEC generating units are presented in Exhibit 7-2. Major fuel characteristics for the fuel utilized at the SENELEC power generating stations are presented in Section 3: Potential Fuel Sources.

Exhibit 7-2
Major Power Generation Plants of SENELEC

Station/ Fuel Type	Unit Capacity, MW	Year of Startup	SO_2	NOx	Part.	CO
301-Cap des Biches (steam)/ Heavy fuel	25.80 x 1	1966	230 kg/h 8.9 kg/MWh	56.8 kg/h 2.2 kg/MWh	16.3 kg/h 0.63 kg/MWh	4.39 kg/h 0.17 kg/MWh
302-3 Cap des Biches (steam)/ Heavy fuel	28.10 x 2	1977/78	500 kg/h 8.9 kg/MWh	124 kg/h 2.2 kg/MWh	35.4 kg/h 0.63 kg/MWh	9.55 kg/h 0.17 kg/MWh
101 Bel Air (steam)/ Heavy fuel	9.20 x 4	1953	328 kg/h 8.9 kg/MWh	81.0 kg/h 2.2 kg/MWh	23.2 kg/h 0.63 kg/MWh	6.26 kg/h 0.17 kg/MWh
TAG 1 Cap des Biches (gas turbine)/ Diesel oil	15.0 x 1	1972	14.7 kg/h 0.98 kg/MWh	51.0 kg/h 3.4 kg/MWh	2. 85 kg/h 0.19 kg/MWh	3.45 kg/h 0.23 kg/MWh
TAG 2 Cap des Biches (gas turbine)/ Diesel oil	20.00 x 1	1984	19.6 kg/h 0.98 kg/MWh	68.0 kg/h 3.4 kg/MWh	3.80 kg/h 0.19 kg/MWh	4.60 kg/h 0.23 kg/MWh
TAG 3 Cap des Biches (gas turbine)/ Diesel oil	20.00 x 1	1995	19.6 kg/h 0.98 kg/MWh	68.0 kg/h 3.4 kg/MWh	3.80 kg/h 0.19 kg/MWh	4.60 kg/h 0.23 kg/MWh
401-2 Cap des Biches (diesel)/ Heavy fuel	18.00 x 2	1989	302 kg/h 8.4 kg/MWh	504 kg/h 14 kg/MWh	10.4 kg/h 0.29 kg/MWh	115 kg/h 3.2 kg/MWh
403 Cap des Biches (diesel)/ Heavy fuel	23	1997	193 kg/h 8.4 kg/MWh	322 kg/h 14 kg/MWh	6.67 kg/h 0.29 kg/MWh	73.6 kg/h 3.2 kg/MWh
BOOT Cap des Biches (gas turbine)/ Naphtha I	50	1999 In Constr.	10.5 kg/h 0.21 kg/MWh	215 kg/h 4.3 kg/MWh	12.0 kg/h 0.24 kg/MWh	11.5 kg/h 0.23 kg/MWh
TAG Bel Air (gas turbine)/ Diesel oil	37.00 x 1	1999 Proposed	36.3 kg/h 0.98 kg/MWh	126 kg/h 3.4 kg/MWh	7.03 kg/h 0.19 kg/MWh	8.51 kg/h 0.23 kg/MWh
105-6 Bel Air (diesel)/ Heavy fuel	4.5 x 2	1990	75.6 kg/h 8.4 kg/MWh	126 kg/h 14 kg/MWh	2.61 kg/h 0.29 kg/MWh	28.8 kg/h 3.2 kg/MWh
Total Nameplate Rating - Installed Total Nameplate Rating - by end of 1999	218.8 MW 306. MW					

Assumes an average heat rate of 11,318 kJ/kW-hr

No ambient air quality monitoring is carried out in or around the alternate sites. There are no other significant major sources of air pollution in the vicinity of the sites, and it is assumed that the air quality in the area will be dominated by the proposed SENELEC generating facilities. When the project moves forward, the following checklist should be re-examined for changes in the air quality situation.

AIR QUALITY CHECKLIST:

1. Regulations affecting air emissions, allowable emission rates;

2. Ambient air quality standards for the area;
3. Permit and monitoring requirements for new sources of air emissions;
4. Other sources of air emission in the vicinity of the selected site; and
5. Ambient air quality in the vicinity of the sites.

7.1.2 Impacts on Surface and Groundwater

Fresh water is a scarce commodity in Senegal and especially in the Dakar area. The proposed plant's potable water requirements (including makeup water for the condensate system, fire water and sanitary water) is estimated to be about 220,000 m^3/year (or 125,000 m^3/year if gas fired). Dakar has a chronic water shortage problem and the excessive use of water could deprive segments of the general population of potable water. Seawater cannot be used directly for potable water requirements, and desalination and demineralization would result in reduction of total energy efficiency due to the energy consumption for treating seawater water.

Discharge Standards

At present there are no water discharge standards which have been adopted in Senegal. As a guidance, the World Bank's maximum effluent levels for new thermal power plants are summarized, in Exhibit 7-3. The following effluent levels should be achieved without dilution.

Exhibit 7-3
Effluents from Thermal Power Plants

Parameter	Maximum Value
pH	6 - 9
Total suspended solids	50 mg/l
Oil and grease	10 mg/l
Total residual chlorine[a]	0.2 mg/l
Chromium (total)	0.5 mg/l
Chromium (hexavalent)	0.1 mg/l
Copper	0.5 mg/l
Iron	1.0 mg/l
Nickel	0.5 mg/l
Zinc	1.0 mg/l
Temperature increase	less than or equal to 3°C[b]

[a] So-called "chlorine shocking" may be preferable in certain circumstances. This involves using high chlorine levels for a few seconds rather than a continuous low level release. The maximum value is 2 mg/l for up to 2 hours, not to be repeated more frequently than once in 24 hours, with a 24-hour average of 0.2 mg/l (the same limits would apply to bromine and fluorine).

[b] The effluent should result in a temperature increase of no more than 3 degrees Celsius at the edge of the zone where initial mixing and dilution takes place. Where the zone is not defined, use 100 meters from the point of discharge when there are no sensitive aquatic ecosystems within this distance.

Discharge Overview

Impacts on surface and groundwater during construction and operation will need to be assessed. Predicted discharge quantity and quality from the proposed facility will need to be within allowable discharge requirements to ensure compliance. Any recommended mitigation measures for predicted surface and groundwater impacts will be described in this assessment. When the project moves forward, the following checklist should be should be re-examined for changes in the water discharge situation.

WATER QUALITY CHECKLIST:

1. Regulations/restrictions affecting water withdrawal from both surface and groundwater sources;
2. Amount of water available from the selected source (city water, well, desalination unit);
3. Regulations affecting water discharges (both surface and groundwater) and discharge limitations;

4. Water quality at the selected site;
5. Discharge permit requirements for new sources of water discharges;
6. Other sources of water discharges in the vicinity of the selected site (potential water sources); and
7. Restrictions on construction in or affecting water (e.g., maximum water intake velocity, or discharge diffusers).

7.2 IMPACTS ON HABITAT, ENDANGERED SPECIES, AND ARCHAEOLOGICAL, HISTORIC AND CULTURAL RESOURCES

Impacts expected from the recommended facility on habitat, endangered species, and archaeological, historic, and cultural resources will need to be assessed. This evaluation should make use of existing environmental information/reports/studies to describe the ecological baseline conditions and resources, and to indicate any future concerns for the area in the vicinity of the facility. Impacts on habitat, endangered species, and archaeological, historic, and cultural resources should be addressed by identifying those areas early in the project and, where possible, avoiding those areas of concern during construction of the facility. When the project moves forward, the following checklist should be examined for the archeological, historical and cultural resources situation.

Archeological, Historic and Cultural Resources Checklist. Identify the following:

1. Any known or suspected archeological, historic or cultural resources in the vicinity of the selected site that should be avoided;
2. Demographics of the site vicinity; and
3. Any religious shrines, cemeteries, burial plots, monuments, schools, playgrounds, parks, hospitals, etc.

Animal life

When the project moves forward, the following checklists should be should be addressed to identify important habitat considerations, and threatened or endangered species.

Habitat Checklist:

1. Identify critical habitats, including floodplains, farmland, grazing areas; and

2. Identify protected trees in the vicinity of the selected site [Section 6 of the Forestry Code (95-357)].

Endangered Species Checklist:

1. Identify any known or suspected endangered or threatened species (animal and vegetation) in the vicinity of the sites as well as the location of any habitat that may be unique to their nesting or migration that should be avoided.

7.3 REFERENCES

"Pre-Feasibility Study on Project for Construction of Diesel Power Plant at Tobene," Republic of Senegal, Societe Nationale d'Electricite (SENELEC), March 1993.

"Senegal Power Plant - Definitional Mission Report," ENPRO, August 1995.

"National Geographic Atlas of the World," Fifth Edition, 1981.

"New York Times Atlas of the World," Fourth revised concise edition, 1994.

"Senegal-GTi Dakar," Project No. 007821, WAIS Document Retrieval, May 22, 1997.

"Forestry Code," Environmental Decree 95-357, Ministry of the Environment, April 11, 1995.

SECTION 8: CONCEPTUAL DESIGN AND COST ESTIMATE

This section presents a conceptual design of the combined cycle power plant based upon a selected combustion turbine configuration. For the purpose of developing the combined cycle conceptual design, the ABB GT8C unit was selected. It is recognized that other engines are also manufactured in this class, particularly the Westinghouse 251B11, and that they may prove attractive during the final bidding/selection process. Specific future issues that may prove relevant during the final selection process would include the following:

- Competitive bidding undertaken at a time when the construction is being undertaken,
- The availability of the combustion turbine delivery in a manner that meets the construction schedule as finally determined, and
- The potential design evolution of the combustion turbine models, notably the GT8C2, which may present an attractive alternative at the time of competitive bidding.

For purposes of developing a conceptual design, however, we have selected the GT8C combustion turbine as the basis for the following reasons:

- The GT8C combustion turbine has been in service for approximately ten years. It has an extensive service history in combined cycle applications similar to that anticipated in Senegal and has enjoyed high reliability in this service.
- The preliminary selection of the ABB GT8C over the Westinghouse 251B11 is based upon the ABB machines higher efficiency, as discussed in Section 4, coupled with a reported equivalent capital cost in a combined cycle application.

The purpose of this feasibility design is to demonstrate the practicality of the utilization of a combined cycle plant in this application. We consider the use of the ABB GT8C machine to be appropriate for this purpose, but recognize that conditions at the time of bidding the project may dictate another selection as the optimum design for economic reasons. The information developed in this conceptual design is preliminary and will be developed further depending upon the final site selection, fuels, finalization of combustion turbine selection, etc.

8.1 PLANT CONFIGURATION

The Kayar IPP Project is a combined cycle power generation facility comprised initially of one ABB GT8C combustion turbine generator (CTG), one fired heat recovery steam generator (HRSG), and one steam turbine generator (STG). The condenser is a once-through type, cooled by sea water. The balance-of-plant equipment will be selected to provide the operational flexibility required to produce and supply a nominal net electric output of 70.9 MWe. The projected plant performance as developed here is of estimate quality and is intended to serve as a basis for development decisions. Guaranteed plant output, fuel consumption, emissions and noise will be provided during the detailed design phase by the developer and Engineer, Procure & Construct (EPC) Contractor.

All presented design data are preliminary and are subject to change during the course of detailed design, following this feasibility study. The plant description provided in the following sections can serve as a basis for system approaches and capacities, component redundancy, and scope of supply.

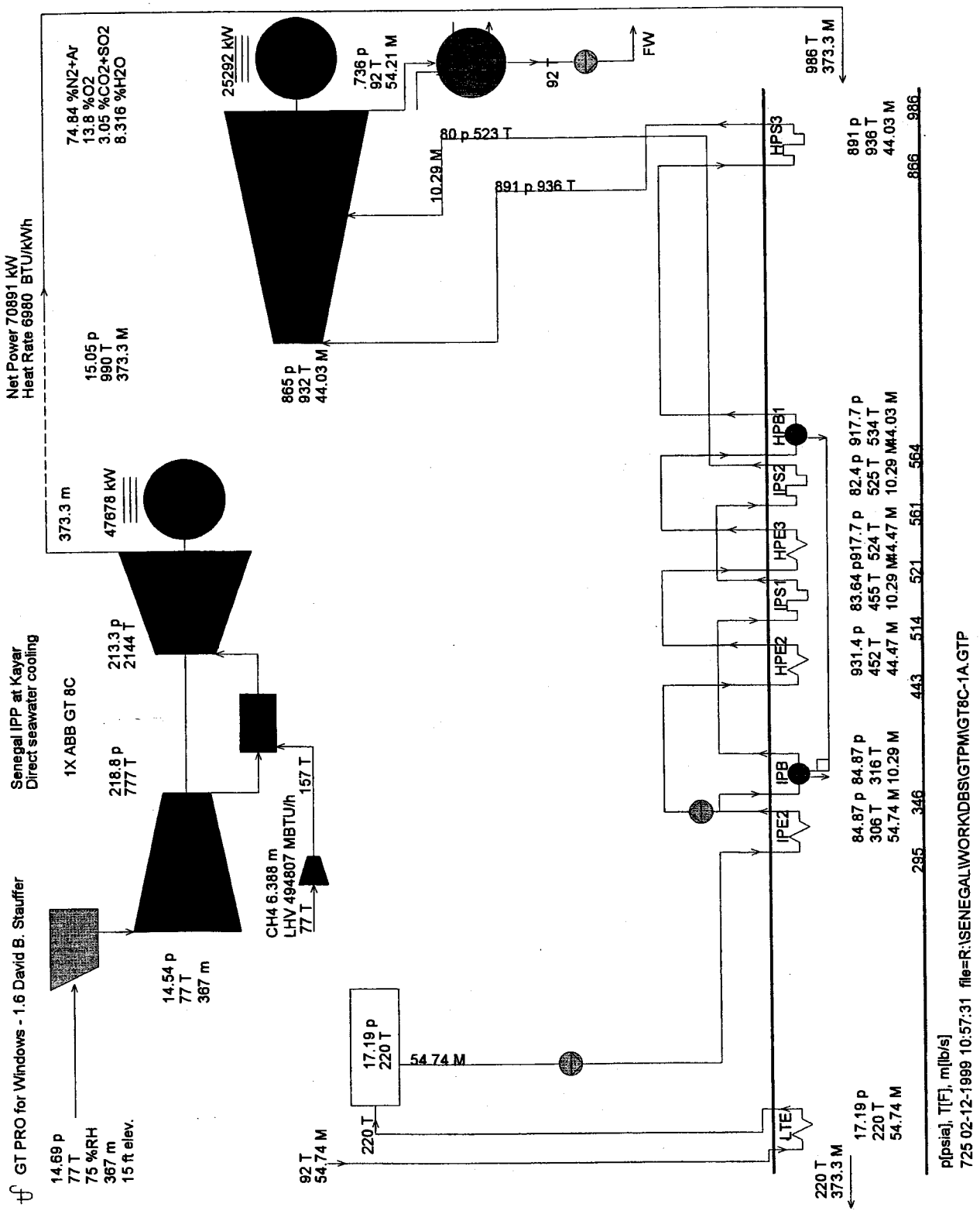
8.2 PLANT DESIGN CONDITIONS

The following site and process conditions were used for the specification of equipment and for determination of plant operating conditions:

Site Conditions		
Elevation		~15 ft. above Mean Sea Level
Design (Summer) Dry Bulb Temperature		107°F (41.7°C)
Average Annual Dry Bulb Temperature		77°F (25°C)
Design (Summer) Wet Bulb Temperature		84°F (28.9°C)
Average Annual Wet Bulb Temperature		71°F (21.7°C) [75% R.H.]
Average Seawater water Temperature		70°F (21.6°C)
Seismic Zone		Zone 0-1
Primary Fuel Source		Natural Gas
Back-up Fuel Source		Diesel Oil
Makeup Water		Treated Raw Water
Process Conditions (Natural Gas Firing)		
Plant Nominal Capacity	ISO	77.9 MWe
	Gross	73.0 MWe
	Net	70.9 MWe

A preliminary heat balance for the ABB GT8C combined cycle for the above conditions is presented in Exhibit 8-1. [Note: this heat balance is different than that used in the screening study that assumed a cooling tower. This Kayar heat balance assumes direct seawater cooling.]

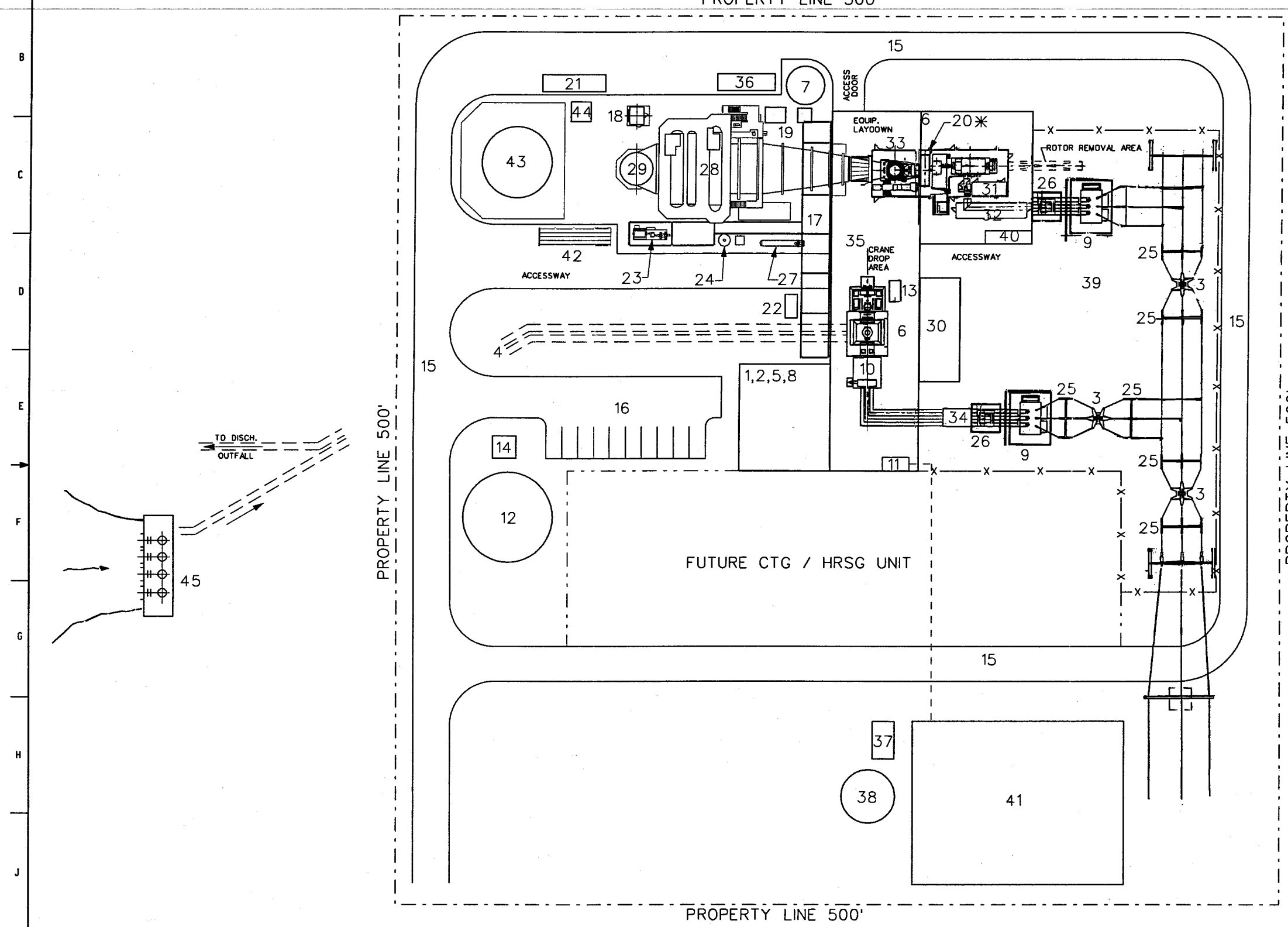
Exhibit 8-1
Kayar-Specific Conceptual Design Heat Balance for an ABB GT8C



8.3 GENERAL PLANT ARRANGEMENT

The plant will be arranged with the CTG and the HRSG located outdoors and the STG located indoors. Peripheral systems will be organized to minimize piping and electrical runs. A typical plant layout, identifying the location of the major equipment components is presented in Exhibit 8-2. It should be noted that this layout is not optimized specifically for the Kayar site, but is intended to demonstrate the Kayar site concept and to provide a basis for making conceptual design decisions. Specific features of the site design and layout are as follows:

1. Allowance has been made for the installation of a second, future generating plant of the same capacity.
2. The cooling system will be installed such that the civil works for the pumphouse are adequate to support the future unit.
3. The water system will be provided with a raw water storage tank sufficient to contain the required plant site fire water storage and to allow for twenty four (24) hours of full load operation on gas firing. This will allow time for maintenance of the water supply system, settling basin, etc. without curtailment of power production. The raw water storage tank will have sufficient storage to allow for the second unit.
4. The diesel oil storage tank will provide for three (3) days of full load operation. This will permit time to arrange for truck deliveries of diesel oil should the gas supply be interrupted.
5. The combustion turbine will be provided with a bypass stack, thus allowing the machine to operate in a simple cycle mode and be capable of rapid startup. The plant will further be provided with a 30% bypass to facilitate steam turbine startup from an operating combustion turbine.
6. The combustion turbine is capable of operating in "peak" firing mode where the unit operates at 70 MW (ISO), thus allowing an additional 17 MW during emergency conditions.
7. During the final design phase, consideration should be given to the use of inlet air chillers. This design feature will chill the incoming air to approximately 49°F, thus allowing a substantial improvement in generating capacity during periods of high ambient temperatures.



NOTES:

EE

LEGEND

1. ADMIN. BUILDING
2. MAINT. SHOPS
3. CIRCUIT BREAKER
4. CIRC. WATER SUPPLY & RETURN
5. LABORATORY
6. GENERATION BUILDING
7. CONDENSATE STORAGE TANK
8. CONTROL ROOM
9. STEP-UP XFMR.
10. STEAM TURBINE GENERATOR
11. OIL / WATER SEPERATOR
12. SERVICE / FIRE WATER TANK
13. LUBE OIL SKID
14. S.W. / F.P. PUMPHOUSE
15. ROAD
16. PARKING
17. PIPE BRIDGE
18. CEMS BUILDING
19. HRSG B/D DRAIN PUMPS
20. CTG AIR INLET FILTER *
21. FUEL OIL UNLOADING APRON
22. GAS METER SKID
23. FEEDWATER PUMPS
24. HRSG BLOWDOWN TANK / SUMP
25. DISCONNECT SWITCH
26. AUXILIARY XFMR.
27. FUEL GAS HEATER
28. HRSG
29. HRSG STACK
30. SWITCHGEAR ROOM
31. ELECTRIC STARTING PKG.
32. CTG ELEC. / MECH. PKG.
33. GTBC COMB. TURB. GEN.
34. GEN. BREAKER
35. CRANE COVERAGE AREA
36. TRAILER MTD. R.O. UNITS
37. WASTEWATER PUMPING STATION
38. WASTEWATER EQUALIZATION TK.
39. SWITCHYARD
40. AIR COMPRESSORS
41. RUN-OFF POND
42. HYDROGEN TUBE TRAILER
43. FUEL OIL STORAGE TANK
44. FUEL OIL PUMP HOUSE
45. CIRC. WATER PUMP STRUCT.

* ON ROOF. NOT SHOWN

Exhibit 8-2

REV	DATE	DESCRIPTION	DRAWN	REVIEWED	LEAD DESIGNER	ENGINEER	LEAD DISCIPLINE ENGR.	PROJECT ENGINEERING MANAGER	PROJECT MANAGER

STATUS OF DRAWING	DEFINITION	CONSTRUCTION STATUS
PRELIMINARY	REPRESENTS GENERAL DESIGN CONCEPTS UNDER DEVELOPMENT. NOT REVIEWED NOT CHECKED.	

DRAWN BY: VJB DATE: 01-03-99
CHECKED BY DATE
LEAD DESIGNER DATE
ENGINEER DATE
LEAD DISCIPLINE ENGR. DATE
PROJECT ENGINEERING MANAGER
PROJECT MANAGER

PARSONS
PARSONS ENERGY & CHEMICALS GROUP INC.
PERSONS OFFICE

CLIENT/PROJECT TITLE
U.S.T.D.A.
SENEGAL
COMBINED CYCLE PLANT

KAYAR SITE ARRANGEMENT

SCALE

PARSON'S DWG. NO. 430011-SK-M-1

REV

Following is a brief description of major and supporting plant equipment and systems.

8.4 MECHANICAL SYSTEMS

The following mechanical plant systems are discussed below:

- Primary Steam
- Feedwater System
- Condensate System
- Backup Oil Fuel Storage
- Fuel Delivery Systems
- Circulating Water System
- Closed Cooling Water System
- Raw Water / Firewater Systems
- Water Treatment System
- Plant Drainage System
- Compressed Air System
- Boiler Chemical Feed System
- Circulating Water Chemical Feed System
- Sampling System
- Fire Protection System

8.4.1 Primary Steam

Two pressure levels of steam will be produced in the HRSG. Superheated HP steam produced in the HRSG will be first fed to the high pressure section of the STG. The HRSG's superheated LP steam will be introduced into the low pressure section of the STG.

The steam system will include a partial flow steam bypass. During start-up, steam produced can be bypassed directly to the surface condenser, which will be rated for a nominal 30% MCR. This feature will alleviate the problems associated with temperature matching, etc. during startup when the combustion turbine is operating at full load. A desuperheater will be provided to condition the bypass steam prior to entering the condenser. Additional let down stations are to be provided external to the HRSG to maintain proper steam temperatures during normal operation.

The HRSG will be provided with natural gas fired duct burners to allow for "fine tuning" the temperature of the steam supply to its optimum value.

8.4.2 Feedwater System

Feedwater will be drawn from the deaerating condenser hot well by three 50% capacity condensate pumps. During periods when the combustion turbine is firing natural gas, the water will be delivered to the

condensate preheater portion of the HRSG. During periods when the combustion turbine is firing diesel oil, the condensate preheater will be bypassed to increase the stack gas temperature.

The boiler feedwater will be delivered to the HRSG by three (3) 50% capacity boiler feed pumps. The main discharge from the pumps will be directed to the high pressure steam circuit of the HRSG. The low pressure circuit of the HRSG will be supplied by the interstage bleed from the boiler feed pumps.

The condensate/feedwater system will be provided with the following design features:

1. The condensate system will be provided with a 30% capacity return line to the condenser to provide adequate minimum flow for the condensate pumps.
2. Each boiler feed pump will be provided with its own dedicated minimum flow line to assure that each of the pumps has adequate minimum flow.
3. The system will include a bypass to allow the HRSG condensate preheater to be bypassed during periods when the combustion turbine is firing diesel oil.
4. The high pressure boiler feed system will be provided split range control valves. The smaller valve is for feedwater control during periods of low steam flow (including startup) and the larger is used for higher steam flows.
5. The condensate system will be used for boiler fill when there is no pressure in the sysem.

8.4.3 Condensate System

The steam exhausting from the STG will be condensed in the surface condenser. The condensate formed will then be collected in the unit's hotwell (with ~3 minute storage capacity) and pumped out using three (3) 50% capacity condensate pumps.

Demineralized water makeup will be introduced into the condenser hotwell.

Noncondensibles in the steam will be removed by the electric motor-driven vacuum pumps. Provisions for chemical addition into the system will be made to control corrosion and pH levels.

8.4.4 Backup Oil Fuel Storage

The combustion turbine will be arranged to fire diesel oil as a backup fuel. The oil system will be arranged to permit full load operation of the combustion turbine during periods when natural gas is curtailed. The oil system will be designed with the following features:

1. Oil storage will be provided on site to permit three (3) days operation. This is intended to permit truck deliveries to be initiated to support further operating if required.
2. The plant will be provided with truck unloading facilities sufficient to permit offloading at a rate sufficient to sustain full load operation of the plant. (Presuming a 3500 gallon (13.25 m^3) capacity in each truck, this will require a delivery every 55 minutes.)

8.4.5 Fuel Delivery Systems

Natural gas fuel (the primary fuel) will be provided to the site metering point by the gas pipeline supplier. The gas pressure required at the combustion turbine main shut off valve must be a minimum of 2,455 kPa (356 psig). It is assumed for purposes of this evaluation that the gas supply pressure is adequate to meet this requirement. If the gas supply pressure is inadequate for this purpose, then a gas compressor will be required.

8.4.7 Circulating Water System

Station heat loads, with the exception of loads from CTG auxiliaries, will be dissipated to the atmosphere by the circulating water system and the auxiliary cooling water system. Direct sea water cooling will provide the heat sink. Two 50% capacity vertical circulating water pumps will draw cooling water from the ocean intake structure and pump it through the tube-side circuit of the steam surface condenser. The circulating water system will also provide cooling to two (2) closed cooling water heat exchangers. Return water from these closed cooling water heat exchangers will be discharged into the main circulating return header. The CTG will be supplied with its own fin-fan air coolers, which operate independently.

8.4.7 Closed Cooling Water System

With the exception of the CTG, equipment cooling requirements will be satisfied by the closed loop cooling water system. Two 100% capacity closed cooling water pumps will circulate condensate-quality water in a closed loop through the shell side of the shell-and-tube heat

exchangers and equipment coolers. A small head tank will be provided to maintain system pressure and serves as a convenient location for necessary chemical treatment additives and make-up water required by small losses.

The equipment cooled in the closed cooling water system will include the STG generator coolers, STG lube oil coolers, plant air compressors and compressed air after coolers, and miscellaneous sample coolers.

8.4.8 Raw Water/Fire Water System

Fresh water, either from the local city supply system, from wells or from a plant desalination unit, will be furnished to meet the plant's operating requirements. It is assumed that the city water supply will be adequate and will be available. This may depend to some extent on current local water development projects now being assessed.

The fresh water supply will be delivered to a site clarifier and from there will be pumped to the raw water storage tank. The system will be provided with the following features.

1. The raw water tank will have sufficient water storage to allow for two (2) hours of fire fighting efforts in a manner that is reserved for that purpose. In addition, sufficient capacity will be provided to allow for twenty four (24) hours of operation of natural gas firing.
2. The system will be provided with a water treatment system capable of supplying the demineralized water necessary for plant operation. The capacity of the system will be sufficient to allow for the simultaneous operation of the combustion turbine on oil firing (estimated demand as 15 m^3/h [65 gallon per minute, gpm]) and the required makeup for the HRSG (estimated as 3.4 m^3/h [15 gpm]). An additional 4.5 m^3/h (20 gpm) capacity is provided with the intent of providing the system with makeup capacity.
3. Raw water will be supplied from the raw water tank by two (2) 100% capacity pumps. It will provide makeup for the demineralizing system. It will also provide water for general plant use.
4. The Fire Water Pumps will supply water to the plant main fire loop. Both an electric motor-driven and Diesel engine-driven fire pump will be provided, both on automatic standby. Each pump will be capable of handling the anticipated fire water requirements of the site. A small jockey pump will be included to maintain system pressure.

The water system will be sized to meet the demands of the generating plant. These demands are summarized below in Exhibit 8-3. These quantities indicate that the water demand for the plant will normally be approximately 21.1 m^3/h (93 gpm). However during periods of natural gas curtailment, when the facility is operating with distillate oil as the primary fuel, the water demand will be approximately 36.6 m^3/h (161 gpm).

Exhibit 8-3
Plant Water Demand Summary

Item	Units	Natural Gas	Diesel Oil
Inlet Clarifier Blowdown	gpm	5	8
Demineralized Water Requirement			
Cycle Makeup	gpm	15	15
CTG Water Injection	gpm	0	65
Pretreatment System Blowdown	gpm	10	10
Demin. Regeneration Requirement	gpm	3	12
Total Water to Demineralizer System	gpm	28	102
General Plant Use	gpm	50	50
Potable Water Use	gpm	10	10
Total Water Demand	gpm	93	161
	m^3/h	21.1	36.6

Note: 1 m^3/h = 4.403 gpm (gallon per minute)

8.4.9 Water Treatment System

The water treatment system will provide water of suitable quality for water injection into the combustion turbine and for makeup to the steam cycle. The plant may be either an ion exchange system or a reverse osmosis system. Raw water will be pumped through the demineralizer system to the Demineralized Water Storage Tank. The tank will be carbon steel, and will be sized for the larger of the following two criteria:

1. The tank will be sized to permit 48 hours of operation at full load while firing natural gas.
2. The tank will be sized to permit three (3) complete system fills to expedite startup and chemical cleaning.

The demineralized water treatment system will capable of processing 10.2m^3/h (100 gpm) of raw water. The demineralizer system will be two (2) 100% capacity trains capable of on-line regeneration. The system shall be capable of 10 years continuous operation, with a 75% water recovery rate, and 90-95% TDS rejection.

8.4.10 Plant Drainage System

All non-oily and non-chemical water collected from the on-site, non-permeable surfaces will be discharged into the plant waste water.

The plant will be provided with a waste water lagoon sufficient to collect the rainwater which falls on non-permeable areas that have the risk of oil or contamination. The lagoon will be capable of accommodating the "ten year" design storm over 24 hours. This is presumed to be 150 mm of water falling in 24 hours. The lagoon water will be drained though an oil-water separator and passed into the plant waste water.

Potentially oily areas within the plant will be drained to an Oil/Water Separator. The water will then be drained to the plant waste water.

After separation, the oil in the oil water separators will be pumped to the Oily Waste Storage Tank. The products collected in the tank will be pumped out periodically via commercial disposal services for offsite recycling or disposal. The separated water will be discharged to the sewer system.

Areas subject to chemical/or large oil spills will be contained for manual removal and suitable disposal.

8.4.11 Compressed Air System

The facility is provided with a redundant instrument and service compressed air systems. Two (2) 100% capacity compressors will be furnished, with each unit sized to provide the plant's total air requirements.

Both compressors will discharge into a common air receiver. The air receiver will be sized to eliminate pulsations in the air supply originating from the compressors.

The system will be arranged to prioritize the instrument air supply. During periods of low air pressure, the second air compressor will be started automatically. Subsequently, the air supply to the service air system will be automatically shut off to assure continued air to the instrument air system.

8.4.12 Boiler Chemical Feed System

Chemical feed equipment will be provided to facilitate the addition of chemicals into the HRSG system. These chemicals will be added to protect the system components in direct contact with the steam, condensate or water against corrosion and scaling.

A phosphate feed system will be supplied to provide controlled quantities of coordinated phosphate solutions into both the high and intermediate pressure steam drums. This will maintain the optimum pH level of the boiler water and prevent scaling. The phosphate feed system will consist of solution tanks, metering pumps, piping and controls and will be pre-assembled on a common skid.

An oxygen scavenging system will be provided to feed chemicals into the boiler feed pump suction.

8.4.13 Circulating Water Chemical Feed System

A chemical feed system for the addition of chemicals into the circulating water system will be provided to protect against bio-fouling. Chlorine will be introduced into the system in order to control against biological and bacteriological growth. Chlorine will be injected into the circulating pump intake structure and pumped directly to the surface condenser. The system will be designed for both shot and continuous chlorination.

Residual chlorine levels in the condenser discharge will be monitored and maintained below 0.5 mg/l level.

8.4.14 Sampling System

The sampling system will collect, condition and automatically analyze water and steam samples from the boiler cycle water. The system will provide continuous data pertaining to water chemistry parameters for the boiler feedwater, the boiler water, steam and condensate.

The system will continuously monitor the following sample points:

- Condensate: Conductivity and pH
- Feedwater: Dissolved Oxygen
- Steam: Conductivity
- Blowdown: Conductivity

The system will be housed in a sample panel that will include the wet analyzers, recorders and the sample conditioning equipment. It will also have a sink for grab sampling capacity of all the incoming sampling points.

8.4.15 Fire Protection System

Fire Protection for the facility will be provided as follows:

- A Fire Protection System for the STG lube oil skid will be furnished;

- The Administration Building will be protected by a wet type sprinkler system actuated by heat sensing devices as required;
- The CTG automatic CO_2 fire suppression system will be furnished by the CTG vendor;
- The Central Control Room will be furnished with an automatic CO_2 fire suppression system;
- The Electrical Equipment Room will be supplied with hand held wall-mounted CO_2 fire extinguishers as required;
- All generator transformers will be furnished with a water spray deluge system;
- A fire protection loop will be furnished for the site. The looped system will consist of underground lines with post-indicator valves and hydrants;
- A fire water pumping facility will also be furnished. This pumping system will consist of one electric motor-driven and one Diesel engine-driven fire pump, a pressure maintenance (jockey) pump, storage, and pump connections.

8.5 MECHANICAL EQUIPMENT

Major mechanical equipment is summarized in the "Mechanical Equipment List" in Appendix E. The major components, around which the plant is designed (ie. the combustion turbine generator, the steam turbine generator, the heat recovery steam generator, and the condenser) are described in detail in the following sections.

8.5.1 Combustion Turbine Generator

The ABB GT8C was first introduced in 1984 for 50 and 60 Hz applications. The single welded shaft turbine features a single top-mounted silo type combustor capable of handling multiple fuels. In late 1997, an uprated version, the GT8C2, was introduced with a cleaner burning annular combustor. At ISO conditions[i], the GT8C 50 Hz unit is rated at 52.8 MW with a simple cycle efficiency of 34.4%. (The recently upgraded GT8C2 50 Hz unit is rated at 57.2 MW with a simple cycle efficiency of 34.7%.)

The unit is equipped with an electric motor starting system.

[i] Sea level, 15°C, 60% relative humidity, 100% CH_4.

The combustion turbine package will include a totally enclosed water-to-air-cooled generator (TEWAC), fin-fan cooler, self-cleaning air inlet filter, and control system. The unit will be designed for distillate oil, and natural gas operation, with the following expected performance:

Parameter	Design Value
Ambient Temperature	77°F (25°C)
Fuel	Natural Gas (primary) / Diesel (secondary)
Relative Humidity	70 %
Altitude	15 ft (above MSL)
Gross Output	47,400 kW
Efficiency	32.6%
Gas Consumption (LHV)	496.1 MMBtu/hr (523.3 GJ/hr)
Exhaust Gas Flow	1,358,507 lb/hr (609,600 kg/hr)
Exhaust Gas Temperature	983°F (528.°C)

NOx control will be accomplished through the use of dry low NOx combustors when burning natural gas. When utilizing diesel oil, water injection will be employed (if required for environmental limits). The anticipated emissions are presented below.

Expected Emission Performance

	Natural Gas Firing		Diesel Oil Firing	
Emissions (@ 15% O_2)	100 %	50%	100%	50%
NOx, ppmvd	25	25	42	42
CO, ppmvd	8	8	15	15
SO_2, ppmvd	Nil	Nil	later	later
CxHy, ppmvd*	5	5	30	30
TSP**	3	3	14	14

* CxHy measured as CH_4

The GT8C combustion turbine has been in service for approximately ten years. It has an extensive service history in combined cycle applications, and well-established maintenance procedures, summarized in the following table:

Recommended Inspection Interval

Inspection Type	Intervals	
	Eq. Operating Hours[1]	Starts
Type A Inspection[2]	6000	400
Type B Inspection[3]	12,000	1,200
Type C Inspection[4]	24,000	2,400

Notes:

1. Eq. Operating Hours: Calculated as the summation of effective operating hours and the number of starts times the start weighting factor (one start = 20 hours for normal start).
2. Type A Inspection: Intended for early identification of changes in the condition of parts in the hot gas path, initiation of any rectification action, checking of operation settings important for availability, and general inspection of condition. The minimum length of time necessary is 48 hours from shutdown to startup. Requires one (1) manufacturer's representative and three (3) plant personnel. The total number of manhours normally budgeted for this effort is 80 hours.
3. Type B Inspection: Intended to include Type A tasks plus checking of the safety equipment of the gas turbine set, hydraulic and electronic closed loop control systems, and open loop controls and annunciation system. The minimum length of time for this inspection is 64 hours. The personnel required includes three (3) manufacturer's representatives and six (6) plant personnel. The total number of manhours required for this task is 210 hours.
4. Type C Inspection: Intended to include the tasks associated with both Type A and B inspections plus the removal of the acoustic enclosures, the turbine combustor, the turbine casing and rotor and removal the generator end shield. The internal blading, combustion chambers, generator components will be examined and renovated as necessary. The minimum length of time necessary for this inspection is from 13 to 15 days. The personnel required includes nine (9) manufacturer's representatives and twenty three (23) plant personnel. The total number of manhours required for this task is 2485 hours.

8.5.2 Heat Recovery Steam Generator (HRSG)

The HRSG will be a two-pressure level unit with a dual fuel duct burner, and all piping and valving required for complete installation, with the following expected performance:

Parameter	Design Value	
	English	Metric
High Pressure Steam		
Pressure	865 psia	60 bar a
Temperature	932°F	500°C
Flow	158,520 lb/hr	71,900 kg/hr
Low Pressure Steam		
Pressure	80 psia	5.5 bar a
Temperature	523°F	272°C
Flow	37,040 lb/hr	16,800 kg/hr

The HRSG is intended to be a complete steam generating unit as necessary to meet the performance requirements of the plant. The scope of the HRSG will include, but not be limited to, the following:

- High pressure superheater, evaporator and economizer;
- Low pressure evaporator and feedwater preheater coil;
- High pressure steam drum with internal steam separators;
- Low pressure steam drum.
- Boiler casing with internal insulation;
- Free-standing stack, 100ft (30.5m) above grade, complete with breeching openings and emissions monitoring ports.
- HRSG inlet duct complete with shop installed internal insulation, CTG-to-HRSG expansion joint
- Gas fired duct burner
- Boiler valves and trim as required by ASME code, and BFW controls (end elements only);
- Interconnecting piping between heat transfer sections;
- Platforms, ladders, and stairs;
- Structural steel for support of all equipment.

The deaerating condenser will be designed to deaerate HRSG feedwater to 7 ppb of oxygen.

8.5.3 Steam Turbine Generator

The steam turbine generator (STG) will be a condensing turbine generator, rated at 25 MW, and will be provided with a single low pressure steam admission port. The steam turbine package will include the generator (TEWAC), generator controls, lube oil system, turbine governor and controls, and other accessories necessary for reliable operation. The following is the expected performance:

Parameter	Design Value	
	English	Metric
Throttle		
Flow	158,520 lb/h	71,900 kg/h
Pressure	865 psia	60.0 bar a
Temperature	932°F	500°C
LP Admission		
Flow	37,040 lb/h	16,800 kg/h
Pressure	80 psia	5.5 bar a
Temperature	523°F	272.°C
Exhaust Pressure	1.5 inch Hg	51 mbar a
Gross Output	25,300 kW	25,300 kW

8.5.4 Steam Surface Condenser

The surface condenser will recover turbine exhaust steam for re-use in the power cycle at a nominal exhaust pressure of 1.5 inches HgA (51 mbar a), for the design circulating water temperature. The preliminary design duty for the condenser is 195.1 GJ/h (185 MMBtu/h) with a 8.3°C (15°F) temperature rise, and 21.1°C (70°F) circulating water inlet temperature. During start-up conditions, steam produced can be bypassed directly to the surface condenser. A desuperheater will be provided to condition the bypass steam prior to entering the condenser. The condenser will be designed for a nominal 30% mcr (to be confirmed during detail design).

The condenser will be a two-pass unit with divided waterbox and non-divided hotwell. The tubes, tubeheets, shell, hotwell, supports and water box will be corrosion resistant materials suitable for seawater service, such as titanium, admiralty, cupro-nickel, etc. Feedwater deaeration will occur within the surface condenser.

8.6 ELECTRICAL SYSTEM DESCRIPTION

This section describes the conceptual approach to electrical system design.

8.6.1 General

The Electrical Power System will encompass electrical equipment and cable/raceway systems necessary for the transformation, switching, control and protection power for the following purposes:

1. Generator to the Generator Step-up Transformer,
2. Generator Step-up Transformer to the Transmission system,

3. Distribution to auxiliary loads and services internal to the generating facility,
4. Critical plant systems requiring uninteruptable service.

Project design, supply and operation will be in accordance with the applicable local codes and standards or the referenced ANCI/IEEE/NEMA codes and standards.

8.6.2 System Design

Electrical power generated at 22.5 kV by the CTG and 11.5 kV by the STG is stepped up to 90 kV by one three-winding, 90 kV grounded wye, 22.5 kV delta and 11.5 kV delta, main step-up transformer. A 90 kV breaker will be provided in the switchyard for protection of the plant and to provide a means to automatically separate the facilities electrical system from the utility electrical system when a fault occurs.

Future development of the site may dictate that the planned 225 kV transmission line between Tobene and Cap des Biches be looped through the station. Therefore, it is recommended that the high-voltage winding be designed to be reconnectable for operation at 225 kV. The high-voltage switchyard should also be designed for future 225 kV operation as well as for the installation of additional generating units at the site.

Two auxiliary transformers will be provided to supply the plant's in-house electrical system, one from the 22.5 kV bus of the CTG and one from the transmission system. During normal operation of the facility, power for the in-house load will be supplied from the CTG 22.5 kV bus.

A 3300 V system will be provided, and will be fed from the 22.5 kV bus via the 22.5/3.3 kV auxiliary transformer, rated 3000/4000 kVA OA/FA .

Motors 200 hp and larger, will be connected to the 3300 V bus via medium voltage fused contactor-type motor controllers.

The 380 V auxiliaries of the CTG, STG and Balance-of-Plant will be fed from the 3300 V system via 3300/380 V auxiliary transformers and 380 V switchgear and motor control centers (MCCs). The 380 V switchgear buses will be provided with drawout type, manually operated power circuit breakers to feed the MCCs.

Motors smaller than 200 hp, the lighting transformers, and other small auxiliaries will be connected to the MCC buses. Each motor supplied from a MCC will be controlled by a combination motor-starter supplied with a manually operated 380 V circuit breaker or motor circuit protector.

The 125 V DC system will provide a source of reliable, continuous DC power for plant control, protection, instrumentation, switchyard controls, and other DC loads required for normal operation and an orderly and safe shutdown of the facility.

120 V AC instrument power for critical instrumentation and controls will be supplied by an Uninterruptable Power Supply (UPS). The system will consist of a DC/AC static inverter with a bypass constant-voltage transformer fed from a 380 V MCC. The regulated 120 V AC supply may, additionally, be used for other loads requiring a power source with close voltage tolerances.

8.7 ELECTRICAL EQUIPMENT DESCRIPTION

This section describes the conceptual approach to electrical equipment design.

8.7.1 Utility Interface

The utility interface will consist of the following equipment and devices:

- Transmission Line; 90 kV, single circuit (by others);
- Protection, Telemetering and Status Monitoring Signals over the Overhead Fiberoptic cores will be between the existing utility substation and the facility's switchyard.
- Two Protective Relays; a current differential type with direct transfer trip capability, and a distance relay (double-zone type), at both ends of the 90 kV transmission line.
- Remote Terminal Unit (RTU); Communication with the utility's load dispatch center via leased telephone lines.

8.7.2 Communication with Load Dispatch Center

A leased, dedicated, telephone line is proposed for communication with the electric utility's load dispatch center.

8.7.3 90 kV Switchyard

The 90 kV switchyard equipment will be designed for 120 kV class and will consist of the following items:

- Five air-break disconnect switches (120 kV, 1200 A, three-pole, 61 kA rms momentary, 450 kV BIL);

- Three metering units (90 kV L-L, single-phase, 400/800:5A current element ratio; one double-secondary PT, 2000/1200:1 ratio, 90 kV primary and 110 V secondary, 450 kV BIL);
- One Power Circuit Breaker (52) (120 kV, 1200 A, three-pole, 40 kA rms sym. IC, 900 kV BIL, SF_6 dead-tank type);
- Three Capacitor-Coupled Voltage Transformers (CCVTs) (54 V phase-to-neutral, single phase, ratio 1200/2000:1, 450 kV BIL);
- Main three winding step-up transformer (70/90 MVA, OA/FA, 65°C rise, 3-phase, 50 Hz, 90/22.5/11.5 kV, grounded wye-delta-delta, 450/---/110 kV BIL, 9% impedance at 90 MVA, with station-type lightning arrestors);
- A transformer protection panel with devices 50/51 (Qty: 3), 51G, 87 (Qty: 3), and 86 (Qty: 2);
- One line protection panel with current differential-type protection with direct transfer trip capability, and devices 21L (single-zone type), 27L, 27 (DC), 67L, 67N and 86;
- One Utility Enclosure (Pre-engineered metal building with HVAC, for metering and protection equipment); and
- One Remote Terminal Unit (RTU) for utility SCADA interface.

8.7.4 115 kV Power Generation System

The salient items included in the 11.5 kV power generation system are as follows:

- Cable for CTG leads (25 kV, ---- BIL outdoor-type, 2000 A continuous;
- Cable for STG leads (15 kV, 110 kV BIL outdoor-type, 2000 A continuous;
- Generator breaker for the CTG (25 kV, 1000 MVA, 2000 A continuous;
- Generator breaker for the STG (15 kV, 1000 MVA, 2000 A continuous;
- One Auxiliary Transformer (3000/4000 kVA, OA/FA, 65°C, 11.5/3.3 kV, 95-60 kV BIL, delta-wye connected, 2(+) and 2(-) 2 1/2 % FCNL taps in primary, Z=5.5%, w/primary bushing CTs, neutral bushing CT, and neutral grounding resistor assembly rated at 400 A, 60 sec.); and
- One fused disconnect switch, rated 15 kV, 600 A continuous provided on the primary side of the Auxiliary Transformer.

8.7.5 3300 Volt System

The 3300 Volt System will consist of the following equipment:

- One Medium Voltage Vacuum Circuit Breaker (350 MVA, 5 kV, 1200 A, draw-out, indoor type) cable connected to the 11.5/3.3 kV auxiliary transformer described above; and
- One Medium Voltage MCC (3300 V, three-phase, three-wire, indoor type), complete with 1200 A, 40 kA rms asymetrical. braced buses, and seven FVNR fused vacuum contactors each rated at 360 A.

8.7.6 380 Volt System

The 480 Volt System is comprised of one auxiliary transformer, low voltage breakers, low voltage switchgear, and motor control centers for BOP, STG and CTG units.

8.7.7 DC System

The 125-V dc system will be located in the Battery Room, and will provide control power for 90 kV power circuit breakers; the 11.5 kV generator breaker; CTG and STG emergency and other loads, including relays; and the uninterruptible power supply system.

8.7.8 Uninterruptible Power Supply

An Uninterruptible Power Supply (UPS) system consisting of an inverter, rated 20 kVA, 125 V DC 110/220 V, three (3) phase, 50 Hz, will be supplied for critical instrumentation and control loads and a 25 kVA, 380-110/220 V, three (3) phase, bypass isolation transformer.

The UPS will be provided with a zero-break static transfer switch with automatic retransfer capability, a make-before-break manual bypass switch, and current-sensing circuits. A UPS panel with circuit breakers will also be included.

8.7.9 Miscellaneous Electrical Systems

Miscellaneous plant electrical systems include the Lighting System, Communication System, Grounding System (including the switchyard), Lightning and Surge Protection System, Electrical Raceways, and Cathodic Protection.

8.7.10 Motors

Motors rated 200 hp and above will be three (3) phase, squirrel-cage induction motors with a voltage rating of 3300 V. Integral horsepower motors, 200 hp and below, will be three (3) phase squirrel-cage motors rated 380 V. In general, fractional horsepower motors, 1/3 hp and below, will be rated 110 V, single phase.

Motors installed indoors will be furnished with open drip-proof enclosures, unless required otherwise by location or special application. Motor enclosures for outdoor service will be NEMA II weather-protected or totally enclosed.

8.7.11 Protection, Controls, and Instrumentation for Electrical Power Systems

The electrical design of the Project will be based on centralized controls, monitoring, and protection with a minimum of local control stations and switches. The substation, main generating units, plant auxiliary electrical system, and essential auxiliary motors will be controlled from the control room. Non-critical auxiliary loads will be controlled locally at the loads or from MCCs. In general, motors will have one point of control.

The CTG and STG will be capable of operating in parallel with each other and with the 90-kV utility electrical system. The controls provided will be able to maintain the required output, frequency, voltage and continuity of service demand. At the same time, these controls will also provide protection to plant personnel and equipment under all operating conditions.

To obtain maximum operating reliability, the basic design of electrical equipment will be such that the necessity for interlocks and the requirement for control functions are both minimized. Control devices and monitoring devices necessary for startup, shutdown, normal, and emergency operations will be provided in the control room. It is envisioned that an area load- frequency control system, and a power system stabilizer may be required.

The DC system will be used for the operation of control circuits wherever practicable for reliability. Motor control center circuits and some control and instrumentation circuits will operate from AC control power supplies, with arrangements to prevent the dropping out of motor-driven auxiliaries during voltage dips.

Whenever practicable, the control circuits will be designed to allow continued unit operation without change of circuit status. This will

minimize the action required by the operator after a brief loss of control power.

Control equipment will be grouped in a functional manner and provided with control power disconnect devices to facilitate maintenance of one circuit without loss of unrelated circuits. Non-essential fractional-hp motors, lighting, and space heaters will not be connected to vital AC control power sources in order to improve reliability and reduce the load demand on these buses.

Control circuit interlocks and control room supervision of maintenance devices will not be provided unless major hazards are involved.

Whenever practicable, the unit trip initiating and auxiliary lockout relays will be located in cabinets in the central control room area to facilitate testing and to minimize inadvertent tripping while maintaining control circuits.

Off-limit or trouble conditions of electrical systems or equipment will be annunciated by the DCS system.

The protective relays for protection of the generators and plant power transformers will also be centralized and mounted in cabinets located in the control and/or electrical equipment room.

Protection of electrical equipment will be accomplished by means of coordinated relay systems and circuit-breaker operations. This protection system will be designed to offer maximum service dependability and minimum shutdown time due to electrical disturbances.

Each generator will be provided with an automatic and manual synchronizing system that will include:

- Speed matching (Device 15)
- Voltage matching (Device 90 VM)
- Breaker closing with compensation

The generating units and the main step-up transformer will be provided with protection that includes:

- Differential (generator and transformer) (87G & 87T)
- Voltage-restrained overcurrent (generators) (51V)
- Negative-sequence overcurrent (46)
- Phase overcurrent (transformer) (50/51T)
- Overexcitation/Underfrequency (V/Hz)

- Sudden (fault) pressure (transformer) (63P)
- Loss of field (40)
- Generator neutral overvoltage and transformer neutral overcurrent (64N & 51NT)
- Voltage balance (60)
- Generator field ground (64F)
- Stator overtemperature (generator) (49G)
- Winding temperature (transformer) (49T)
- Synchrocheck (25)
- Primary and backup auxiliary lockout relays (86)

The 3300 Volt Plant auxiliary power transformer will be provided with protection that includes:

- Differential (87T)
- Phase overcurrent (50/51T)
- Neutral overcurrent (51NT)
- Sudden (fault) pressure (63P)
- Overtemperature (49T)
- Auxiliary lockout relay (86T)

Utility isolation/separation protection at the 90 kV switchyard will be provided which will include:

- Over/under frequency (81 o/u)
- Over/under voltage (27/59)
- Transmission line directional phase overcurrent (67L)
- Transmission line directional neutral overcurrent (67N)
- Distance Relay (21-L), three-zone type, with timer if required
- Auxiliary lockout relay (86L)

The 3.3 kV switchgear buses will be provided with protection that includes:

- Phase and neutral overcurrent ,
- Phase and neutral undervoltage,
- Auxiliary lockout relay.

3.3 kV motors will be provided with protection that includes:

- Overcurrent (overload and short circuit)
- Stator winding protection (RTD type for motors 1000 hp and above
- Current differential protection for motors 2000 hp and above
- Bearing over-temperature for sleeve bearings.

The 380 V feeder circuit breakers will be provided with solid state type, automatic tripping devices having long-time, short-time, and instantaneous characteristics, as required.

In 380 V motor control centers, the combination starters will be provided with magnetic-only-type circuit breakers and thermal overloads, and feeder circuit breakers will be provided with thermal- magnetic elements.

8.8 INSTRUMENTATION, CONTROLS AND EMISSIONS MONITORING

A description of the preliminary plant control concept is presented in this section.

8.8.1 Functional Control

The plant is designed to operate in a semi-automatic mode with minimal operator intervention; the combustion turbine and the steam turbine are each equipped with capability for "one button" start/stop. In addition, several other auxiliary systems, such as the plant/instrument air system and water treatment system, have the same capability. The plant will be controlled and monitored via a supervisory micro-processor based distributed control system (DCS) which interfaces with individual unit control systems of certain major equipment.

The DCS and its supporting transmitters and input/output loop elements are comprised of proven components of uniform manufacture. These components are selected from manufacturers who have demonstrated reliable operation of the same or similar models of equipment in like service. Reliability of the individual components as well as the integrated system are of prime consideration.

The DCS will consist of multiple CRT units with keyboards and a supervisory control station located in an adjacent office for maintenance, troubleshooting and plant engineers needs. Display units will be provided as required to enable safe, efficient operation of the plant.

The DCS will operate in a monitoring mode with respect to the combustion and steam turbines. "One-button" start/stop function will be provided through the DCS for major plant systems. The balance of plant equipment will generally be controlled via the DCS. Plant equipment which employs local control and monitoring facilities will be connected to the DCS to enable supervision of those equipment without duplication of the control or sequencing logic. Where practical, the DCS will provide "one-button" start/stop and load change features via the data highway to the remote control and sequencing panels. DCS design will incorporate sufficient spare capacity for future growth (including anticipated second unit).

The DCS control room will be equipped with an automatic fire control system suitable for the service.

An Uninterruptable Power System (UPS) will be provided to assure that power to the DCS is secure. Generally, the DCS design and implementation is intended to be a highly reliable control system fully suited for the purpose intended.

Flue gas continuous emissions monitoring will be provided to measure and record SO_x and NO_x. Sample points and monitoring techniques will comply with applicable codes and standards.

Continuous automatic sampling and monitoring of steam and water chemistry will be provided. A centrally located automatic sampling and analyzing system will be employed. Each automatic sample point will include means to obtain a manual sample as well.

Fuel gas calorific value will be measured automatically by an on-line calorimeter.

8.8.2 Major Equipment Control

The paragraphs included in this section provide descriptions of the important control functions provided by the appropriate equipment supplier to support the operation of the plant.

Combustion Turbine Control

The combustion turbine control systems described in this section include those functions required for normal operation. These include modulation of fuel and inlet guide vanes.

The specific combustion turbine fuel control functions are (1) the start-up control, (2) the speed/load control, (3) the exhaust temperature control, and inlet guide vane loop:

1. Start-up Control: The start-up control provides fuel flow as required for firing, warm-up and acceleration.
2. Speed/load Control: The speed/load controls modulate the speed within the range acceptable to the combustion turbine. When the generator breaker is closed, speed is maintained by the utility system and manipulation of the speed/load set point varies the fuel flow and thus the generator output.
3. Temperature Control: The temperature control modulates the exhaust temperature by modulation of the compressor inlet guide vanes and limits maximum exhaust temperature by fuel control.
4. Inlet Guide Vane Loop: The Inlet Guide Vane (IGV) loop modulates the angular position of the compressor inlet guide vanes. Closing the angle reduces the airflow. During start-up, the IGVs are modulated to control airflow. The IGV control maintains the highest allowable exhaust temperature throughout the load range to optimize part load heat rate and minimize steam temperature variation with load.

Steam Turbine Control

The steam turbine generator is controlled from a panel provided by the steam turbine vendor and supervised during operation from the central control room (DCS) operation panel. The electronic turbine controller controls the steam governing valves and the extraction/admission valves according to the parameters set by the operator. The steam turbine control loops operate the main steam control valve. For starting, steam is admitted to the turbine through the main steam stop and control valves. After generator synchronization, the main steam control valves are modulated based on available steam flow and steam pressure. The main stop valve remains fully open during normal operation.

The main steam pressure varies in approximate proportion to the HRSG steam production and the gas turbine load. The sliding pressure control mode minimizes moisture in the steam turbine low pressure stages and optimizes peak and part load operation. The HP steam bypass system controls pressure at low loads and during start-up or shutdown.

Heat Recovery Steam Generator Control

The HRSG energy source is the sensible heat in the gas turbine exhaust. The steam output of the HRSG follows the gas turbine exhaust temperature and flow in accordance with the sliding pressure control and maximum steam drum pressure limits.

Several control subsystems are provided for the HRSG steam and condensate systems. The major control loops are:

1. HP Feedwater/Drum Level Control: High pressure feedwater and drum level control is accomplished by a conventional control system. The primary control uses the superheater outlet steam flow as a set point to the feedwater flow controller. Feedwater flow responds immediately to changes in steam flow. The drum level element adds a trimming component to the feedwater flow controller set point thereby controlling drum level as feedwater flow is adjusted. The steam flow signal is compensated by steam pressure and temperature and the drum level signal is compensated for drum pressure (water density). This provides accurate control of drum level over the variable pressure operating conditions. The feedwater control valve is located at the entrance of the high pressure inlet header to the HRSG. A start-up blowdown control is provided to supplement the feedwater/drum level control during start-up. The start-up blowdown valve opens to remove the excess water if drum water level rises above the control range.
2. LP Feedwater/Drum Level Control: The LP feedwater/drum level control is essentially identical to the HP system. The LP feedwater control valve is located at the LP inlet header.
3. Feedwater Pump Recirculation Control: A minimum flow controller is provided to control the water bypassed from the feedwater pump discharge to the condenser. This maintains flow through the pump above a minimum level which prevents pump from cavitation.

Steam Cycle Auxiliary Controls

Several control loops are included for the major steam cycle auxiliaries to provide a coordinated control system for the steam turbine. Some representative control loops are identified as follows:

1. High Pressure Steam Bypass: The high pressure steam bypass is controlled so as to limit the main steam line pressure during unit acceleration, generator synchronization, and initial steam turbine loading and to allow the steam turbine to be started up in a manner consistent with its permissible temperature gradients independent of the HRSG and combustion turbine operation. During normal loading, the high pressure steam bypass valve is closed. The set point for the high pressure bypass controller is obtained from the start-up sequencing equipment and the high pressure bypass is coordinated with the gas turbine and steam turbine operation. The high pressure bypass steam is desuperheated prior to admission to the condenser, using water from the boiler feedwater system.
2. Low Pressure Steam Bypass: Low pressure steam is bypassed to the condenser during start-up and low load operation. LP steam is

admitted to the steam turbine when main steam flow is admitted to the turbine. The LP bypass is closed during high load operation and opens to limit pressure to the permissible values in the low pressure steam line, particularly during periods when the high pressure steam bypass is opened.

3. Water Make-up to Condenser: Condensate will be delived to the condenser from the condensate storage tank when the hotwell level in the condenser is low.
4. Water Dump from Condenser: The system will be arranged to automatically dump condensate from the condenser to the condensate storage tank during periods when the condenser hotwell level is high.
5. Condensate Pump Recirculation: The recirculation system for the condensate pumps will be controlled to assure that the condensate pumps operate at a flow rate which assures that they will not experience cavitation damage.

Generator Controls

Equipment is provided for the indication, control and protection of the generator and excitation systems for both gas and steam turbine electric generators. Controls of the generator and excitation systems include automatic generator field flashing and synchronizing. An automatic voltage regulator is provided as well as indication of generator functions, i.e., volts, amperes, watts, vars, temperatures, etc. Generator controls also include the excitation lower switch and the generator breaker controls.

8.8.3 Data Communications

Intra-plant data communication is handled by the DCS. Digitized I/O signals are sent by exception over redundant isolated 9600 baud field bus cables from the field bus modules to the node bus. Application processors (hard disks), work station processors (operator consoles), control processors, information network interfaces, and foreign device gateways (data links) communicate over the node bus. The National Grid requirements for electronic data processing reports can be supported by this system.

Intra-plant data communications will be by both above and below ground twisted pair shielded cables connecting the field bus modules located in the Turbine Control Cab to the redundant data highway located in the control room. Off site communications will be by special conditioned telephone lines provided by the telephone company, other public or private carriers or other mutually agreed upon methods.

8.8.4 Instrumentation

The plant instrumentation provides data and information required for the safe and efficient operation of the plant. The Instrumentation systems monitor and control process variables via direct measurement and conversion to analog signals which are processed by the distributed control system (DCS).

Generally, individual transmitters are employed for each separate measurement and control loop, however, in certain limited instances a single element may feed more than one control function. These are practical considerations indicated by the design and the circumstances of the individual control loop.

Field mounted transmitters employ enclosures suitable for their environment, whether they be mounted indoors (per IP-54) or outdoors (per IP-64). Air operated control elements employ individual filter/regulators. Where practical, transmitters will be grouped together in local racks for ease of maintenance. Pressure and flow transmitters are installed with valve manifolds to facilitate in place calibration. Fittings for connection to the process will permit easy removal for maintenance.

Instrument accuracies will be determined during the design stage. Accuracy stated will include the combined effects of environmental and electrical perturbations.

Maintenance intervals for instrumentation will be governed by the application and service requirements. Generally the transmitters and other instruments selected for power plant operation require bi-annual maintenance and re-calibration.

Location of Operation:

There are two locations for operation of the gas turbines. The central control room is the primary location. The configuration includes a group control console for automatic start-up, on-line operation and shutdown of the gas turbines.

The unit local control compartments are secondary locations for operation of the individual units. These compartments will be used infrequently; for example, during the plant installation and checkout phases and while performing maintenance on unit level control systems.

Modes of Operation:

Several modes of operating the plant components are available as follows:

1. Automatic from Central Control Room: All critical plant components can be started, operated on-line and stopped from the plant control room from the DCS control system. The operating functions available from these consoles also include start, stop and operation of the auxiliary equipment so that functions required for normal plant operation can be implemented from these control consoles.

2. Combustion Turbine Control: One operator interface subsystem (OIS), which consists of a CRT and keyboard, is provided for installation in the unit control compartment from which the unit can be started, operated and stopped. Unit starting from the LCC can be performed after the group auxiliaries have been started and the unit brought to ready to start status from the central control room. The primary use of this operator interface is initial starting and checkout and starting and operating following major maintenance on each unit.

8.9 REQUIRED OFF-SITE INFRASTRUCTURE PROJECTS

Off site infrastructure requirements include necessary electrical infrastructure, natural gas supply lines, etc., as discussed in previous sections. The development of the Kayar project needs to be integrated into the planning of the electrical transmission system (new 225 kV system) as well as the gas development by Petrosen and Tullow Oil, and their partners.

8.10 ESTIMATED PROJECT COSTS

An indicative conceptual cost estimate is presented for the combined cycle plant as described above. The Total Project Cost, which is approximately $ 61 million, includes the battery limits project capital costs, off-site infrastructure development costs related to the facility, an allowance for taxes and duties, and an allowance for the project Development Fee. Other project costs have been incorporated into the estimate in the financial analysis. The estimate is based on procurement of an ABB GT8C gas turbine, HRSG and steam turbine generator producing a total plant net output of 77.7Mwe(ISO). Excluded from the cost estimate are:

- Fuel & Chemical Inventory
- Permits & Licenses
- Legal Expenses / Fees
- Owner's Cost During Construction
- Financial Costs, including

- Financing & Closing Fee
- Working Capital
- Debt Reserve Fund

Costs are expressed in 3rd quarter 1998 US dollars, and exclude escalation.

A sophisticated cost model for combined cycle power plants initially generated the capital costs. The cost model was adapted to specifically address the GT8C combustion turbine cycle. The estimate was developed initially based on cost of construction on the US Gulf Coast. The estimate was then adjusted on the basis of Parsons' recent EPC experience to reflect current market conditions, and to incorporate expected in-country productivity and wages for Senegal, as well as any site specific features that could be recognized.

In addition to the combined cycle power and steam generating equipment, major plant equipment for this project includes a water-cooled condenser, fuel gas compressor, CEMS, distributed control system, step-up transformers and high voltage equipment. This non site specific estimate, in terms of scope and cost impacts, did include consideration of a sea water cooling system. The contractor's costs include all other components of the plant, labor and materials for erection, and the contractor's fee and profit. The estimate represents an indicative project cost and is representative of results to be expected from a lump sum turnkey bid solicitation.

Off Site Costs associated with the facility are comprised of allowances for a high pressure gas line to the site boundary, cooling water intake structure and pipe, an electrical substation and HT lines, and road construction. In addition, a contingency allowance is included for the off-site costs for scope elements that are not identified at this time.

The Total Project Cost summary for the land based combined-cycle power plant, excluding costs incorporated in the financial analysis, is provided in Exhibit 8-4. The Capital Cost Summary is presented in Exhibit 8-5.

Exhibit 8-4
Total Project Cost Summary

Project: SENELEC
Description: GT8c gas turbine, 1x1 configuration, IPP grassroots plant, 77.7 MWe-net(ISO)
Location: Kayar, Senegal

		% Project Cost
Total Conceptual Project Cost (refer to estimate summary)	**$48,300,000**	64.9%
Taxes & Duties	**$2,415,000**	3.2%
Total Conceptual Project Cost w/Taxes	**$50,715,000**	68.1%
I. Plant Costs		
Facility Cost	Included above	0.0%
Off-Site (Gas & Electric)	$6,400,000	8.6%
Subtotal	**$0**	8.6%
II. Startup & Inventories		
Spare Parts (during startup only)	Included above	0.0%
Fuel & Chemical Inventory	Working Capital Facility	0.0%
Start-Up (contractor labor only)	Included above	0.0%
Subtotal	**$0**	0.0%
III. Development Costs		
Permits & Licenses	Included below	0.0%
Development Fee	$4,000,000	5.4%
Legal Expenses / Fees	$1,500,000	2.0%
Owner's Cost During Construction	N/a	0.0%
Subtotal	**$5,500,000**	7.4%
IV. Financial Costs		
Financing & Closing Fee	$1,500,000	2.0%
Working Capital	Credit Line	0.0%
Debt Reserve Fund	$4,612,850	6.2%
Interest During Construction	$5,698,094	7.7%
Subtotal	**$11,810,944**	15.9%
Total Project Cost	***$74,425,944***	100.0%

Cost Basis:

1. 3rd quarter 1998 US dollars.
2. Excludes escalation.
3. Off-Site for Gas & Electric Connections is an allowance
4. Development Fee is an allowance.

Exhibit 8-5
Conceptual Capital Cost Summary

Land Based Power Plant at Kayar, Senegal, 1 X 1 Combined Cycle			
I	Specialized Equipment	30,755,000	
II	Other Equipment	1,413,000	
III	Civil	1,272,000	
IV	Mechanical	2,617,000	
V	Electrical	1,521,000	
VI	Buildings & Structures	426,000	
VII	Engineering & Plant Startup	2,751,000	
Sub-Total Contractor's Internal Cost		**$40,755,000**	
Contractor's Soft & Miscellaneous Costs		7,545,000	
Contractor's Price		**$48,300,000**	
Owner's Soft & Miscellaneous Costs		0	
Total - Owner's Cost (US$)		**$48,300,000**	
Net Plant Output, Mwe(ISO)		77MW	
Cost per kW –Contractor's (US$/Kw)		$622	
Preliminary Cost of Off-Site Projects			
High Pressure Gas Line to Site Boundary[a]			$2,700,000
Cooling Water Intake Structure and Pipe			$750,000
Electrical Substation and HT Lines			$1,700,000
Road Construction			$ 250,000
Contingency			$1,000,000
Subtotal Off-Site Projects			**$6,400,000**

8.11 U.S. SOURCES OF SUPPLY

Potential U.S. sources of supply have been identified for this project and are presented in Exhibit 8-6.

Exhibit 8-6:
Potential U.S. Sources of Supply

Equipment/Service Area	Supplier
Gas Turbine-Generator	General Electric Siemens-Westinghouse Solar Turbines United Technologies
Steam Turbine-Generator	General Electric Siemens-Westinghouse Dresser Rand Elliott Company Murray Turbomachinery
Electrical Equipment	General Electric Allen-Bradley Company BICC Brand-Rex Industrial Cables Constant Power Mfg. Company Custom Power Cutler-Hammer Delta Unibus, Inc. Dependable Power Systems Kuhlman Electric Corp. Magnatek Paige Electric Co., L.P. Pennsylvania Transformer Technology, Inc Powell Electrical Smit Transformer Sales, Inc. Solidstate Controls, Inc. Square D Sytstems Control Association VA Tech Ferranti-Packard Transformers, Inc. Virginia Transformer Company Waukesha/North American Transformers
Heat Recovery Steam Generators	Babcock & Wilcox Deltak Foster Wheeler Nooter/Erikson Vogt-NEM Zurn Industries
Large Power-Island Pumps	Aurora Pumps Flowserve Gould Pumps Ingersol-Dresser Pumps Lawrence Pumps, Inc.

Exhibit 8-6 (Continued):
Potential U.S. Sources of Supply

Steam Surface Condensers	Balke-Durr Inc. Foster Wheeler HoltecYuba Heat Transfer
Cooling Tower	Balke-Durr Inc. Baltimore Aircoil Ecodyne GEA-ITC Hamon Cooling Towers Marley Cooling Tower Company Psychrometric Systems, Inc.
Control System	Bailey Foxboro Honeywell, Leeds & Northrup, Rosemount Westinghouse
Water Treatment	Aquatech International Corporation Culligan International Corp. Ecolochem Graver Water Systems, Inc. Hungerford and Terry, Inc. Illinois Water Treatment Ionics Komline-Sanderson Medro Systems, Inc Osmonics Riley Equipment Co. Water & Power Technologies US Filter
Engineering, Procurement, and Construction Management	Parsons Energy & Chemicals Bechtel Black & Veatch Burns and Roe Duke - Fluor – Daniel Jacobs Engineering/Stone & Webster Morrison Knudsen/Raytheon Sargent and Lundy

SECTION 9: FINANCING ANALYSIS AND PLAN

Concepts of financing a new independent power project in Senegal are discussed in this section. Since the type of financing plans and structures can change depending on the financial markets' situations, the host country's economic status, and other events which can impact financing structures, the following will also discuss plans that are not representative of the current market. Two financing plans recommended for the project are discussed in Sub-Section 9.4.3.

9.1 TYPES OF FINANCING - BASIC CONCEPTS

The following paragraphs describe several types of financing and their applicability to SENELEC.

9.1.1 Sovereign Guaranteed Lending.

In typical Sovereign lending transactions, the Minister of Finance (Central Bank) would be the borrower or the unconditional debt guarantor to the lenders. The lenders could be multilateral institutions such as the World Bank or the African Development Bank (ADB), export credit agencies such as U.S. Ex-Im Bank, Japan Ex-Im Bank, ECGD, on Hermes, or even commercial banks (such as Citibank, ING, etc.). Regardless of the institution, those lenders would require the Sovereign to be responsible for ultimate repayment of the debt, regardless of the actual uses of the funds. The responsibility for timely debt repayment in the currency of the designated loan would rest entirely on the Minister of Finance.

Such loans would have a pricing (the interest rate) and tenor (duration of loan) dependent upon the credit rating of the Sovereign. In a number of situations these loans can be priced much lower than those available to an IPP. Usually, so as not to destabilize certain commitments with the multilateral lenders, the host country should maximize the sourcing of equipment from one or two markets with export credit agencies (ECAs) or development agencies willing to provide long term financing against the sovereign's guarantee.

Adaptability to SENELEC: Currently this is not a suitable or required option for SENELEC or the Sovereign. A previously financed IPP sets a

strong precedent and allows the Sovereign to consider shifting the financial burden of a new plant away from the public sector. In addition, the Sovereign is under close watch by the IMF to ensure that few Sovereign guarantees are issued. This type of guarantee would only be warranted if the cost to the Sovereign can be recouped from a significant difference between the offered power tariff from an IPP project versus that being derived from a Sovereign backed financing.

9.1.2 Corporate Finance.

Corporate financing is based upon the credit worthiness, balance sheet, cash flow, and historical track record of an ongoing commercially profitable business of the borrower. The willingness of lenders to provide such financing will be based not just on the total assets of the corporate borrower, but far more importantly on its cash flow available for servicing debt, and its track record in making timely payments of obligations.

It is not uncommon for new, first time corporate borrowers in the international marketplace to seek a credit rating from a recognized credit rating institution (Moody, Standard & Poor's, other) in which there is a thorough evaluation of the corporation's likely ability to repay indebtedness on a timely basis. Commercial and official lenders then accept the rating provided by the recognized international rating agencies, and the pricing and tenor of loans are based upon that credit rating. The higher the credit rating, the lower the cost of capital to the borrower.

Adaptability to SENELEC: As a state-owned-enterprise undergoing privatization, this option may be available to SENELEC since it would not affect the Sovereign's balance sheet (to the extent of private ownership). If SENELEC's plan is to own this new generation facility then, in addition to an off-balance sheet financing structure (traditional IPP structure), this financing structure can be tapped up to the amount that SENELEC is able to comfortably afford to pay. SENELEC is familiar with this form of financing, as this occurred for the newest 28 MW gas turbine supplied by Greenwich Turbines (GTI). SENELEC will need to go through an exercise of a pro-forma projection incorporating the reduced cost of power as a result of the latter turbine, the new IPP being constructed by Nuovo Pignone for Greenwich Dakar Ltd., and then the incorporation of the savings derived from this potential project. It is likely that SENELEC'S future cash flow position can be seriously enhanced as a result of these three separate project/cost savings.

SENELEC could also become a partner with an IPP and could finance its share of the equity investment through a corporate financing. We

are not recommending that SENELEC take on the burden of financing the new plant; however, this is a possible structure.

The upcoming privatization of a majority of SENELEC's shares will likely result in an international strategic partner such as a major IPP or electric utility firm. SENELEC's new ownership may be more inclined to take on the additional financial burden of the development of an IPP. Conversely it may solicit tenders for an internationally competed IPP project. Regulations and resulting negotiations with the winning bidder may create a framework that prohibits or promotes the participation by SENELEC's new shareholder in the Project. However, the intent in the current privatization is for SENELEC to evolve as a distribution company, limiting its generation ownership to currently owned plants.

9.1.3 Limited Recourse Project Finance.

In a limited recourse project financing, lenders will be looking to the cash flow of the business enterprise (the project) itself of the source as the repayment of debt, rather than to a corporate or Sovereign undertaking. By definition there will be no track record for the new Project Company in repaying debt, as it will be a start-up enterprise. The security to lenders that their loans will be repaid on a regular and timely basis and in full, comes from the properly and tightly structured allocation of risks and responsibilities to each of the parties who play a critical role in the project company actually performing well, generating revenue, and being able to repay its debt.

In a power project, the principal parties on whom the project will be dependent in order for it to generate revenue according to expectations, will be:

a) the power purchaser;

b) the fuel supplier(s);

c) the plant operator;

d) the turnkey, or Engineer, Procure, and Construct (EPC) contractor (including equipment suppliers) who must deliver on time, on budget, and according to agreed performance specifications, a power plant that will function according to the proforma commercial and financial projections prepared for the project.

Additionally, various parties must also be assigned the obligation to perform certain required tasks, such as the obtaining and maintenance of all permits (operating, environmental, land use, construction, etc.). Insurance for various commercial risks and catastrophic losses must also be in place.

Adaptability to SENELEC: SENELEC has already spent considerable time and effort, and expense, in successfully implementing an IPP

project on a limited recourse basis. A subsequent project will require less time, effort and expense. This structure will not rely on the Sovereign guarantee but should require a performance guarantee from the Ministry of Finance (MOF) as secured for the first project. Whether for a 100% foreign owned or partially SENELEC owned project, SENELEC will have to participate in a Power Purchase Agreement (PPA) similar to the one already committed to. The main disadvantages to a limited recourse project are the creation of such project documents, establishing the legislation supporting an IPP project, and agreeing to the conditions set by lenders. Assuming that much of the latter work effort can be contributed to a new project, the limited recourse option is currently the most attractive for SENELEC.

The analysis of SENELEC's financials seem to provide a positive outlook in respect to creditworthiness. However, since a precedent has been established with the new GE Capital (formerly GTI) 50 MW project, it is likely that the lenders for the new project will require similar pledging of SENELEC's receivables. These would have to be other receivables, which may or may not be of sufficient quality. This issue is discussed later.

9.2 FINANCING ISSUES

In general, investors will provide equity financing for a project if risks are reasonable in relation to target returns (for equity directly and through contractual relationships with the project, such as EPC and O&M contracting), and if lender requirements affecting the developer are not too onerous.

A major objective of the feasibility study's financial analysis is to optimize the project's debt structure. This is based on obtaining the largest amount of debt with the lowest margin and fees and the longest tenor, while maintaining reasonable debt coverage ratios and debt:equity proportions. In order to achieve this ideal setting, a number of key elements and conditions must be in place. These elements and conditions are addressed below.

9.2.1 Project Economics

A project's economics will determine to a great extent whether raising financing is even viable, or on what terms it is secured. For projects with weak economic fundamentals, financing will be difficult to obtain and financing costs will be relatively high. In such cases, lenders may require the developer to offer guarantees and other credit enhancements (addressed below) to provide reasonable assurance of timely and full debt repayment, which may not be acceptable to the developer. In general, tariff structures must be adequate to provide

revenues to cover financing costs (e.g., debt payments), return on invested capital, and operation and maintenance costs.

9.2.2 Project Structuring.

Project structuring refers to the nature of the arrangements between key entities involved in the project, such as the agreements between the project company and the offtaker (i.e., purchaser of the project's output), project company and key suppliers (e.g., gas supply agreement), implementation agreement, if necessary, addressing arrangements between the Government and the project company with respect to the Government's obligations on a range of implementation issues (e.g., rights of way).

The range of agreements must involve the key entities and allocate risks to those entities best positioned to manage the risks. For example, the turnkey construction contractor is required to provide a warranty (performance guarantee) to ensure the facility operates in accordance with performance standards and liquidated damages in the event of delays in starting commercial operations because they are in the best position to manage such risks.

Incomplete and inadequate project agreements that fail to identify and manage the key risks may preclude the possibility of raising debt financing for a project.

9.2.3 Contracts

In project finance, the web of contracts provides the critical framework for the creation of economic value and determining the financial viability of the project. Certain key contracts essential for an IPP are discussed briefly below.

Implementation Agreement

An Implementation Agreement provides the overall framework for implementing the project, including establishing the key obligations and rights for the Government and/or other project participants and the project. This Agreement and/or the Power Purchase Agreement (PPA), for example, may specify performance standards the project must achieve (minimum available capacity), establish penalties for failure to perform, address Government and other parties' obligations with respect to building, operating, and maintaining key supporting infrastructure (interconnections) not within the project company's scope and other matters (land use and environmental permits). An implementation agreement is not always required, especially for projects where key issues outside the immediate scope of the project can be addressed in the PPA.

Power Purchase Agreement

The Power Purchase Agreement between the offtaker(s) and the project company must address certain key elements in order to enable the project company to raise debt financing, some of which are provided below:

Contract Duration At a minimum, the contract must be equal to the debt repayment period. For capital intensive projects, such as a power plant project, long term financing is often required by the project's economics, which may involve debt repayment periods as long as 12 or more years. For additional cushion for the equity investor, a minimum of 15 years should be considered.

Tariff Structure. A two tier tariff structure likely would be established. A capacity charge would cover the facility's fixed costs including debt payments and include a return on invested capital. A capacity charge would constitute a "Take or Pay" obligation – one that offtaker(s) would have to meet whether or not they actually took delivery of the stipulated quantities of power.

The second tariff component would involve an operations and maintenance charge to cover on-going variable costs (e.g., fuel), other supplies, and maintenance. As with the capacity tariff, this O&M tariff would be escalated to account for inflation, as well as other items such as increases in taxes (which are out of the control of the developer).

Fuel Supply Agreement.

A Fuel Supply Agreement will be required to ensure that the project has access to adequate and reliable fuel over the duration of the debt service period at a minimum. The developer will seek to pass-through all fuel costs, including any future increases in costs, to the offtaker(s). Similar to the PPA, the fuel supplier likely will require the Project Company to enter into a take-or –pay contract that obligates the Project Company to make a capacity or similar tariff whether or not it takes deliver of gas up to a certain quantity. The Project Company will generally require the fuel supplier to meet availability standards.

Other Contracts/Permits

Other Contracts/Permits required for an IPP project in Senegal include:

- Code of Investments approval by the Ministry of Finance
- MOF Letter: repatriation and convertibility between CFA and French Francs or Dollars
- Work Permits from Ministry of Labor
- Ministry of Energy approvals for operations of a plant

- Agreement for the supply of fresh water
- Any tax exemptions negotiated such as Income Tax Holiday, Land, Duty, or other taxes
- Authorization of foreign investment in Senegal from the MOF
- If by seashore, Marine Administration approval for any Sea Water System for cooling the plant

9.2.4 Credit Enhancements

Lenders will evaluate carefully the creditworthiness of all key entities involved in the project, especially the offtakers. Lenders must have reasonable assurance of the ability of the offtakers to fulfill all their obligations under the PPAs, including full and timely payment of tariffs. In the event lenders are uncertain about the ability of the offtaker to fulfill these long term obligations with respect to the project, credit enhancements likely will be required. Credit enhancements may take a number for forms, some of which are listed below (please note these are only examples and may or may not be suitable/desirable for this project):

- Because large offtakers have customers with a revenue stream which is significantly greater than the payments made to the project company, one approach would be to establish an escrow account under a trustee that would receive the electricity payments up to the amount of the next debt payment and certain fixed costs after which the remaining revenues would be released to the offtakers. Under this scheme, lenders to the IPP would have first draw down rights over this account for debt service payments. This scheme, if acceptable to the lenders, might reduce the need for sponsor and offtaker backed credit enhancements. This has often been required with offtakers that have had a history of poor collections, and pose some creditworthiness issues. This mechanism has also been seen to transplant the need for a Sovereign backed performance guarantee, although certain markets have both structures available. The extent of payments to be covered by such escrow accounts will be determined on a case by case basis. SENELEC has already pledged a significant group of customers receivables towards such an escrow scheme for the 50MW IPP project in Cap des Biches. Since a new project will become subordinated (to the extent of those pledged receivables) to the first project if payment problems arise, SENELEC will have to show continued improvement of its own creditworthiness in order to bring comfort to the lenders of a new project. With the latter in mind it is highly likely that an additional performance guarantee will be required for the new project. SENELEC could provide its top customer's receivables not pledged

to the 50 MW project, and others deemed necessary, and provide a similar security package to the new plant.

- If cash flows are not deemed sufficiently robust, lenders may require the developer to provide certain guarantees, for example, by providing a letter of credit from a bank for a certain amount to ensure sufficient cashflow is available to service debt payments.

All forms of credit enhancements generally restrict the flexibility of the entity providing the credit enhancement by diminishing its ability to assume additional obligations. Although the effect of credit enhancements for a single project may not be great, each such undertaking constitutes a precedent for others and the cumulative effect of these obligations can be burdensome.

9.2.5 Security Package.

As a condition of providing debt financing, lenders will require as collateral:

- full charge over the project's assets, including physical assets and cash;
- the project company to pledge its shares as further collateral, which would be released once the debt is retired;
- the assignability of the PPA and other key project contracts;
- assignments of insurances and brokers' undertakings;
- control of escrow accounts and when necessary retain cash flows of the project;
- assignment of long term supply agreements – assignment of rights under project documents, including turnkey contracts, licenses, contractors' performance bonds; and
- assignment of project management and technical assistance agreements.

9.2.6 Construction Risk and Financing Requirements

Developers and by extension the EPC contractors are required to provide warranties for guaranteeing the performance of the facility and liquidated damages if construction delays postpone the start of full commercial operation. Developers and EPC contractors must demonstrate they possess adequate financial resources to provide performance guarantees and liquidated damages. Cost overruns, delays in completion, shortfalls in expected capacity need to be tested by the financial model against the proposed liquidated damages and

other financial guarantee mechanisms provided by the Developers, the EPC Contractor or even the fuel supplier in some instances.

9.2.7 Dispute Resolution Mechanisms

In the event of contract disputes, mechanisms must be provided to address such disputes. In the event of default, all entities must be assured that compensation and other conditions tied to the default event are implemented faithfully and completely. Virtually all international lending institutions will typically require as a condition of lending that disputes be addressed through international arbitration and that the host government waives its sovereign immunity rights with respect to its obligations under the project agreements.

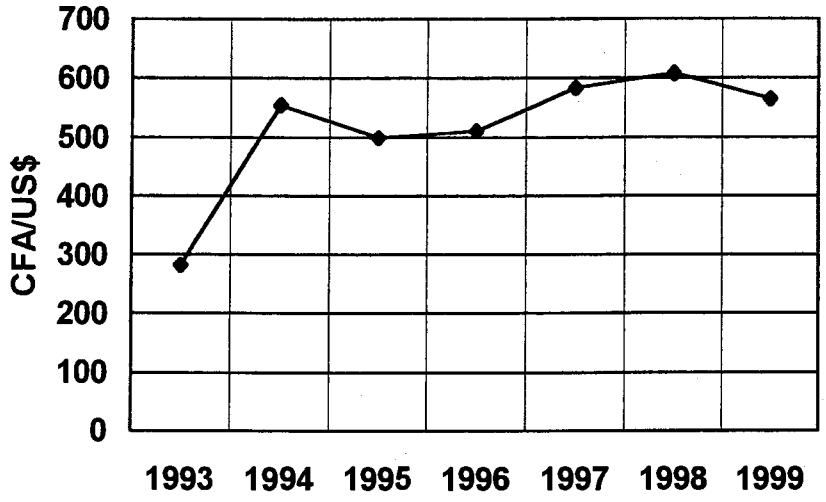
9.2.8 Currency Issues

When debt financing is provided by foreign sources, adequate provisions are required to ensure access to foreign exchange to service debt payments. In the case where local financing is used, convertibility risk would be eliminated in connection with debt service payments. Thus the hard currency obligations of the project will need to be indexed to the US dollar (as a norm), or in the case of Senegal it may be more appropriate in French Francs, while payable in local currency. The MOF and the Central Bank will provide assurances that the local currency will be converted into French Francs on a timely basis, and the monthly payments will have a "true-up" mechanism in order to avoid a loss caused by sudden devaluation during the "conversion" period. The project and the lenders require a hard currency claim on the offtaker/or guarantor.

Unlike many emerging markets, Senegal has an advantage with its currency. The Franc CFA's stability and linking to the French Franc, in addition to being a convertible currency, will generally attract equity investors but will still require further assurances from project lenders. The CFA is utilized in Benin, Burkina Faso, Cameroon, Central African Republic, Chad, Congo Republic, Cote d'Ivoire, Equatorial Guinea, Gabon, Guinea-Bissau, Mali, Niger, Senegal and Togo. It has remained fairly stable against the US Dollar, with a devaluation of approximately 8% in one year's time. The CFA is currently trading at 565.77CFA=$1. Over the last few years the CFA francs per US$1 is shown in Exhibit 9-1.[1]

[1] Beginning 12 January 1994, the CFA franc was devalued to CFA 100 per French franc from CFAF 50 at which it had been fixed since 1948.

Exhibit 9-1
Value of CFA Francs to US$



9.2.9 Developer Financial Requirements.

While many of the financing requirements revolve around lender requirements, developers also have requirements affecting the financibility of the project. In particular, developers seek to achieve a return on invested capital that is commensurate with the level of risk. The return should be sufficient after considering various risk elements, including business risk, technology risk, political risk, sovereign risk, and currency risk in the event profits would be repatriated. We have estimated a minimum requirement of 23% IRR in the base model. Additionally, high withholding taxes on repatriated profits could significantly reduce the effective return to the developer. Currency convertibility risk is also an issue for developers that seek to repatriate profits.

9.2.10 Debt – Equity Ratios

The relative proportions of debt and equity comprising the project's capital structure will depend on the nature of the project, including its risk profile. Additionally, the proportion of debt in the capital structure will have implications for tariff levels as tariffs will need to be sufficient to cover financing costs. While one can expect a range of 25%-35% of equity for power projects, the ultimate percentage will be determined by an appropriate balance of return, debt coverage ratios, acceptable tariff, and risk sharing. The latter can be an issue with certain developers who realize an early repayment of their equity with a frontloaded tariff profile. This can reach extremes in which the equity is entirely repaid by completion. Lenders will seek to trap cash in the project so as to retain sponsor commitment for as long as possible. This front loading has a

negative effect on the tariffs to the host country and should be avoided if possible.

9.2.11 Bankability

In project finance where the cash flows of the project serve as the primary source of funds for debt repayment, cash flow available for debt service in any period (after operating costs and taxes and mandatory reserves as applicable but before distributions to equity) must be projected to be always greater than the amount of the debt payment. The ratio of the cashflow available for debt service to debt payment is referred to as the debt service coverage ratio (DSCR). Lenders will require the DSCR to exceed a minimum threshold value, which will be determined based on the project's economic profile, project agreements, and risk profile. This typically has a minimum range of 1.3-1.4 times Debt Service, and excludes the funds available in a Debt Service Reserve (usually 6 months of Principal and Interest).

9.3 REQUIREMENTS OF FINANCING INSTITUTIONS: LIMITED RECOURSE PROJECT FINANCING

Each potential source of financing has its own lending requirements that can represent advantages and disadvantages to the project. Four general sources, represented by types of institutions, are discussed below.

9.3.1 Commercial Banks

International commercial banks are one source of debt financing for the project. Their participation in Senegal, however, would be limited to co-financing arrangements with multilateral agencies. The reason is that all commercial lenders from the international banking community will require political risk and commercial risk guarantees from "Official" sources of financing, export credit agencies or multilaterals, all of which are governmental or quasi-governmental institutions. This combination is required to provide loans at a reasonable interest rate and long tenors, and hold electricity tariffs as low as possible. Consequently, the financing structure for SENELEC begins with the requirements of the Official sources of financing.

9.3.2 Export Credit Agencies

Export Credit Agencies (including U.S. Ex-Im Bank, ECGD, Japan Ex-Im Bank, Hermes, SACE, and COFACE) are a potential important source of long-term debt financing for the project. As the terms by ECAs will be more generous than those of commercial banks for

virtually all emerging markets, export credits are much sought after and highly suited to the financing of long-term infrastructure projects. This is especially true at the time this document was written.

Most export credit agencies lend on the basis of a sovereign guarantee. However, all of the major OECD export credit agencies have now developed programs that will allow them to provide loans on a true project financing structure. In this regard, the credit on which any loans would be based, would also look primarily to the credit risk of the offtaker(s).

An example of the terms offered by the US EX-IM Bank is provided below.

Financing:	85% of equipment procured in the US
Tenor:	Construction +12-14 years
Interest Rate:	CIRR (or 100-120 basis points over US Treasuries); fixed
Repayment Method:	Even Principal
Term Exposure Fee:	6 – 12% (can be capitalized and amortized over the term of the loan)

US Department of Transportation - Maritime Administration ("MARAD"): The Federal Ship Financing Program

In consideration of a Barge Mounted Plant (Section 10), The Maritime Administration of the Department of Transportation (MARAD) is a US government agency which manages a "Federal Ship Financing Program". The program, known as the Title XI Program, was established pursuant to Title XI of the Merchant Marine Act of 1936 and provides for a full faith and credit guarantee by the US Government of debt obligations issued by U.S. or foreign shipowners for the purpose of financing or refinancing US or export vessels constructed in US shipyards. This program is very similar to the US EXIM Bank as it provides US government backed guarantees for the financing of ships built in the United States. It has financed several power barges in the last few years, including in difficult markets such as Pakistan. The barges are constructed in US Shipyards, and typically have mostly US made equipment. MARAD makes allowances for foreign equipment when such equipment can be proven to be unique, or available in times and prices which are critical to the project's economics, although this decision is very subjective. Nevertheless the power barge industry has evolved considerably and MARAD has helped promote it for various successful developers/constructors.

Obviously MARAD is only suitable to SENELEC if the new project became a power barge. Typically these barges are more costly than oil or gas fired projects, yet MARAD's financing terms, if generous on tenor, could nullify the cost advantage of other designs. See Section 10 for a discussion on an attractive Barge-Mounted Plant option, and the MARAD financing alternative.

9.3.3 Multilateral / Bilateral Institutions

In addition to the ECAs, multilateral/bilateral agencies can provide limited recourse financing to the project. Although funding from these institutions to the private sector is usually provided on commercial rather than subsidized terms, their financing is not tied to the country where the equipment is sourced.

The multilateral/bilateral institutions most interested in assisting in the development of an independent power project in Senegal would be the International Finance Corporation (IFC) - the private sector arm of the World Bank -, the German Investment and Development Company (DEG), and the British Commonwealth Development Corporation. The latter has just announced its participation in a power project in Cote D'Ivoire with a commitment of $23 million out of a $60 million debt financing.

Although the US Overseas Private Investment Corporation (OPIC) has not been active in Senegal commercial risk, the recent increase in interest by the United States Government for Africa make OPIC a potential source of financing as well. OPIC involvement will require a US sponsor with a minimum 25% ownership. OPIC has sufficient capacity for such a project as their limit is $200 million per project, yet usually limited to 50% of project costs.

The IFC can participate in the financing of the project by providing debt from its own accounts (A Loan) as well as by mobilizing debt from commercial banks under a co-financing arrangement (B Loan). According to IFC's 1997 Annual Report, IFC's cumulative gross commitments in Senegal totaled US$60 million and these have grown with their current participation US$16.93 million in debt and equity financing in the 50MW project in Cap de Biches. IFC is reportedly open to participate in the development of the new IPP project. Considered by IFC as a model for private power development in Africa, this project also attracted financing from Italy's export credit agency SACE. IFC often takes a small equity position in the projects.

It is worth mentioning that the IFC's B loan program is currently not a suitable option for Senegal, as well as almost any emerging market. The current situation in the global credit market has taken the typical B-Lenders away from emerging markets. A recent discussion with IFC

members indicated a period of 12 to 18 months for a full recovery of the B-Loan syndication. Thus the A-Loan and equity, as for the previous transaction, should currently be viewed as the extent of the IFC's participation.

An example of the type of terms and conditions offered by IFC is provided below.

Financing:	construction and soft costs
Tenor:	12 years door-to-door (some longer); 2 years grace period
Interest Rate:	Libor + 250-450 basis points
Repayment Method:	Level principal/ level payment
Term Exposure Fee:	0.5 – 1% front end commitment fee

As part of German development cooperation, DEG promotes the private sector in Africa, Asia, Latin America, and Eastern Europe. Its prime concern is to establish and develop efficient private enterprises in these regions through the mobilization of long-term investment capital, technical know-how, management, and marketing expertise.

DEG specializes in strategic investment finance, including long-term loans, equity participation, and sureties and guarantees to secure local loans. As of June 30, 1998, DEG's African portfolio included 118 enterprises in 35 countries, totaling DM 8.3 Billion (approximately 25%of DEG's total portfolio). In Senegal, DEG has provided financing for the construction of a phosphoric acid plant.

Debt financing provided by DEG is mostly denominated in D-mark. In certain cases, however, US dollar denominated loans is available. In an IPP project, for example, DEG can go 10 years door-to-door with 2 years construction grace period. The interest rate, which can be fixed (e.g. 12%) or variable (e.g. Libor + spread), is determined according to the risk profile of the project (e.g. sovereign risk, commercial risk).

DEG can also provide flexible lending arrangements, such as equity-type loans, with built in conversion privilege, profit-linked interest, and/or subordinate collateral. In the case of equity participation, DEG will always retain minority interest in the Project Company.

9.3.4 Local Banks

While we understand that there is liquidity in the Senegal based commercial banks, it is unlikely that this type of financing will be suitable for them. The participation by these banks will be required for working capital purposes.

These projects require working capital facilities to be in place and available throughout the period of the debt. Equity is less concerned about the ability to secure working capital lines post-debt repayment.

Local banks are not accustomed to undertaking large financings, and even a construction period financing with a 2 year tenor will not be palatable.

It is possible that the involvement of the local branch of an international bank, such as in the GE Capital project, for escrow or receivables financing function will be required.

9.3.5 Environmental Compliance Requirements

As part of the technical analysis, heavy oil fired diesel technology was considered and compared to gas turbine technology, in both gas-fired and light oil fired configurations. A sensitivity analysis was also conducted that demonstrated the superiority of the gas turbine, as long as the gas was competitively priced.

Although the heavy oil diesel may be promising on a cost basis, these comparisons do not take into account the impact of differences in air emissions, nor do they consider the difficulty in obtaining financing for the plant. While these type of plants are being financed in some countries, it is primarily where the tariff is sufficiently high, if the host government has low cost domestic oil available for the plant, or there are other very compelling social/economic reasons to follow this path.

Environmental considerations from emerging market infrastructure, especially power, are very real. Usually the benchmarks are World Bank guidelines for ambient emissions, but sometimes the requirements can be even more stringent.

As we proceed with the Senelec project, it is possible that some relaxation of the guidelines could be justified, but for the purposes of this analysis, the more stringent guidelines were assumed for our recommendations.

9.4 FINANCING PLAN

The financing plan suggested hereunder is derived in part from the resulting economics of the power project. These are also generated through the cost assumptions determined by Parsons. Please find in Appendix I the financial model(s) generated for this study.

9.4.1 Project Costs

Parsons generated cost assumptions for the turnkey construction of the plant. These costs can be refined upon the identification of the ultimate site, and once the project is proceeding towards implementation. In addition to Turnkey costs, project costs are typically composed of certain project management costs, development fees, legal fees (development phase), financial advisory fees, owner's engineer, lenders' fees, and interest during construction which is typically accumulated and capitalized in the term loan.

Development fees are usually no less than 2 times the development costs, and for a project this size can be $5 million. Legal fees should be reasonable, as SENELEC has the template of the previous transaction and has the experience of implementing an IPP. We estimate these to be $1-1.5 million depending on the lenders and financing plan selected by the developers. Financial advisory fees will range from 1 to 1.5% of the debt amount, and arranging fees from participating commercial banks, or syndication fees will range from 0.5% to 1%.

The Total Project Costs for the plant are estimated to be $ 74.4 million. Of this amount over 80% is composed of costs which are eligible for Export Credit Agency funding. The Total Project Costs are broken down hereunder in the Sources and Uses chart, Exhibit 9-2.

Exhibit 9-2
Total Project Cost Sources and Uses

USES

Specialized Equipment	30,755,000	41.3%
Other Equipment	1,413,000	1.9%
Civil	1,272,000	1.7%
Mechanical	$2,617,000	3.5%
Electrical	$1,521,000	2.0%
Buildings & Structures	426,000	0.6%
Contractor's Soft & Miscellaneous Costs	$7,545,000	10.1%
Engineering & Plant Startup	2,751,000	3.7%
Subtotal - Contractor's Internal Cost	**$48,300,000**	64.9%
Barge	0	0.0%
Tow and Moor At Site	0	0.0%
Contractor's Price	**$48,300,000**	64.9%
Taxes & Duties	$2,415,000	3.2%
Development Fee	$4,000,000	5.4%
High Pressure to Gas Line to Site Boundary	$2,700,000	3.6%
Contingencies	$1,250,000	1.7%
Cool Water Intake Structure & Pipe	$750,000	1.0%
Electrical Sub Station	$1,700,000	2.3%
Financing Fees/Legal Costs:.....	$3,000,000	4.0%
Working Capital:.....	$0	0.0%
Debt Service Reserve Fund:.....	$4,612,850	6.2%
IDC:.....	$5,698,094	7.7%
TOTAL PROJECT COST:.....	**$74,425,944**	**100.0%**

SOURCES

EQUITY	$22,336,551	30.0%
ECA DEBT	$52,089,393	70.0%
TOTAL	**$74,425,944**	**100.0%**

9.4.2 Equity

We expect that the lenders will require a debt to equity ratio of no less than 3:1 but possibly more like 70:30. The higher equity will compensate for increase in financing costs as it will preserve minimum debt coverage ratios.

The equity will be drawn down on a pro-rata basis with the debt, as the project requires funding.

Equity receives their return through a capacity payment that has either a built-in or clearly identified return component and is part of the tariff.

Sources of equity will be from the IPP developer itself, possibly some related parties such as a lender, and or equipment/fuel supplier or operator. In addition, certain African private equity investment funds

(such as New Africa Opportunity Fund) may be interested, provided the internal rate of returns (IRRs) to them are in the high 20s/low 30s.

9.4.3 Debt

The debt is the most difficult part of the financing plan under a limited recourse structure in an emerging market. In order to secure long term financing in this current banking market and probably for the next 18 months, SENELEC and the IPP developer will have to seek ECAs and/or multilaterals funding. Hereunder are two potential financing plans:

FINANCING PLAN 1: Export Credit Agency Lead

An ECA can limit the number of lenders to a project to one, thus facilitating the financing process considerably. In Cote D'Ivoire for example, a financing is reaching closure for a power project with eight (8) separate lenders. Even though the latter project has a common loan agreement, the efforts undertaken to secure common agreement by all lenders are sure to have been lengthy and costly.

In order to use an ECA as a lead lender to the project, the project developer will have to ensure that:

- Virtually all equipment, engineering, and services are procured from one country. This is due to the fact that the ECA's financing can only be tied to the value of the exports from its jurisdiction. In the case of European ECAs there is an ability to source a minority portion from other European Community members while transacting with just one ECA. This option is generally not available for smaller projects as the ECA needs to justify the financing of other countries' exports and therefor needs to realize a minimum amount of exports from its own.
- The ECA is "open" for Senegal, and this ECA provides suitable comfort to the liquidity providers under such political and commercial risk covers. In the Cap Des Biches project SACE could not have participated without the involvement of the IFC. More ECAs have "opened" since that time.
- The local cost component of the project is limited to approximately 15-20%. With the 25%-30% of equity in the project's funding, sufficient excess funds are then available to cover the ineligible costs to the ECA.

US Ex-Im Bank

Assuming that much of the procurement will be sourced in the United States, US Ex-Im Bank will be a suitable lender. Exim is capable of

doing long tenors for limited recourse transactions and has successfully financed several IPPs around the world.

The new OECD guidelines for export credit agencies allow these to extend 14 year repayment terms with an average life of 7.5, and a fixed interest rate of Treasuries plus 100-120 basis points. This is not necessarily available to all projects and markets, but it is a target for any developer, and is partly in response to increasing pressures on the tariff levels. We assumed a 12 year repayment term for Senegal, in particular considering SACE's tenor in the GE Capital project. A proven developer and a solid EPC contractor with influence on the ECA will considerably enhance the chances of securing attractive terms for financing.

Each ECA charges a premium or exposure fee that is determined by project and country. During the construction period this fee is paid semi-annually and can be around 2% of the amounts drawn down. At completion, when the commercial risk covers are required (depending on the project), the exposure fee can be capitalized, financed and paid down over the term of the debt. This second exposure fee is considerably larger than the first and may be in the range of 6-12% for Senegal and this size project. Commitment fees are also applicable for the amount of cover which is available but not drawn down, varying between the political and commercial risk coverages.

The benefits of Exim bank as a major ECA to SENELEC is that the commercial lenders (liquidity providers) that will participate in the construction financing and possibly the term financing (as long as their cost of financing is more attractive than Treasuries plus 100-120 basis points), will get greater comfort and should translate this into speedier financing and spread reduction.

FINANCING PLAN 2: Multilateral and ECA:

The reasons for introducing a second lender to a transaction can be the same as the one used for the Cap des Biches project, but in this current situation given the availability of various attractive ECAs, the main reason would be to give greater flexibility on the procurement of the equipment.

A multilateral provides untied financing to the sponsors, yet forces them to run an international competitive bidding for the portion of costs that it will finance, unless the project itself was won on an ICB basis (as the GTI plant). For a negotiated transaction, this requirement has been overcome in different ways, the simplest being to run a reduced procurement tender that is sized to the multilateral's participation, and does not overlap the ECA's exports.

In addition to seeking lower project costs with more flexible sourcing, the sponsors may choose this option for Senegal as the IFC has already successfully done one project and should be able to move rapidly through a subsequent transaction. On the other hand, the IFC and SACE have paved the way for other project lenders, and the sponsors for the new project may not want "encroaching" from the Cap Des Biches project lenders. In this case OPIC can be an attractive option.

As a first component of the debt financing, the multilateral (or bilateral in OPIC's case) would provide up to 50% of the project's costs, with the balance being secured from an ECA. OPIC would be available only to the extent the project has a US sponsor with 25% ownership. The terms and cost of financing are going to be very similar for either IFC or OPIC, with the difference that OPIC does not undertake the financial advisory work (which IFC has interest in) and does not require a B-Loan syndication as it essentially self-funds itself for 100% of its commitment through US government guarantees (this process does not affect the borrower).

The co-lending ECA will then be selected according to the procurement. The smaller the financing required the more difficult it becomes to pursue certain of the major ECAs. With OPIC or IFC taking the lead, the requirement of a "major" ECA becomes less relevant and the project can therefore approach a broader selection provided their exporters can supply the needed equipment.

The two lender option will increase the financing process costs. These are likely to double on the application fees, and possibly more with the additional complexity of two lenders and their respective legal and commercial issues to be addressed. There is invariably a longer processing time as a new senior lender is added to a project. SENELEC needs to be sure that these additional costs can be offset by lower project costs that a more flexible procurement could provide.

9.4.4 Project Schedule

The timeline for the SENELEC project to financial close can vary, but in most cases will take a period of several years from the time the concept is unveiled.

It is important to note the significant undertaking in expenses and efforts in the pre-development and development phases. Traditionally, for negotiated transactions, these expenses will be recouped at financial closing in the form of a reimbursement of development expenses (as much as allowed by the different lenders), and a development fee. The longer the period, the greater the development budget, the costlier the total project cost. It is therefore important for SENELEC to proceed with

a competition as expected, and minimize the "development cost" phase and efforts for the winning bidder.

Using this feasibility study and the detailed analysis on the sites and plant configuration options, Senelec will be able to generate a tender document and process that will be attractive to prospective bidders, and will result in an efficient time to financial close. Bidders are diffident of tenders that require considerable self-funded technical analysis, due-diligence, and analysis of "technology options". A significant cost is associated to the development of a proposal that includes design, construction and fuel estimates, in addition to financial structuring. If Senelec can utilize the feasibility study to allow the bidders to minimize their uncertainties and associated costs, then a solid selection of bidders will express interest in the tender.

Considering the detailed work in the feasibility study, SENELEC will be in a position to require a bid which includes the Engineer, Procurement and Construction contractors in the proposal team. The tender documents should also require a financing plan, while not requesting firm commitments on financing. This process will allow SENELEC to proceed more rapidly towards a selection. The Tender Documents and Strategy can be prepared in a 3 month period, and the selection within 3 months thereafter.

Often the delays occur during the time in which project agreements require negotiation and finalization. SENELEC's experience with such documents, and the "bankable" templates available, will prove useful and should considerably shorten the negotiation period. Securing initialed documents ready for the financing phase may require 3 to 6 months. The longer period will depend on the winning bidder and their need to have a fully structured security package prior to approaching the lenders. In parallel to these negotiations the winning bidder will advance the engineering, as well as finalizing the EPC contract.

The next phase for the bidders is the financing. Considering the precedent set by the GE Capital project, if the government of Senegal and SENELEC afford the new project the same privileges and similar contracts, we expect that the financing process will take, from the initialing of key project documents, between 6 and 9 months.

9.5 FINANCIAL ANALYSIS AND COMPARISON

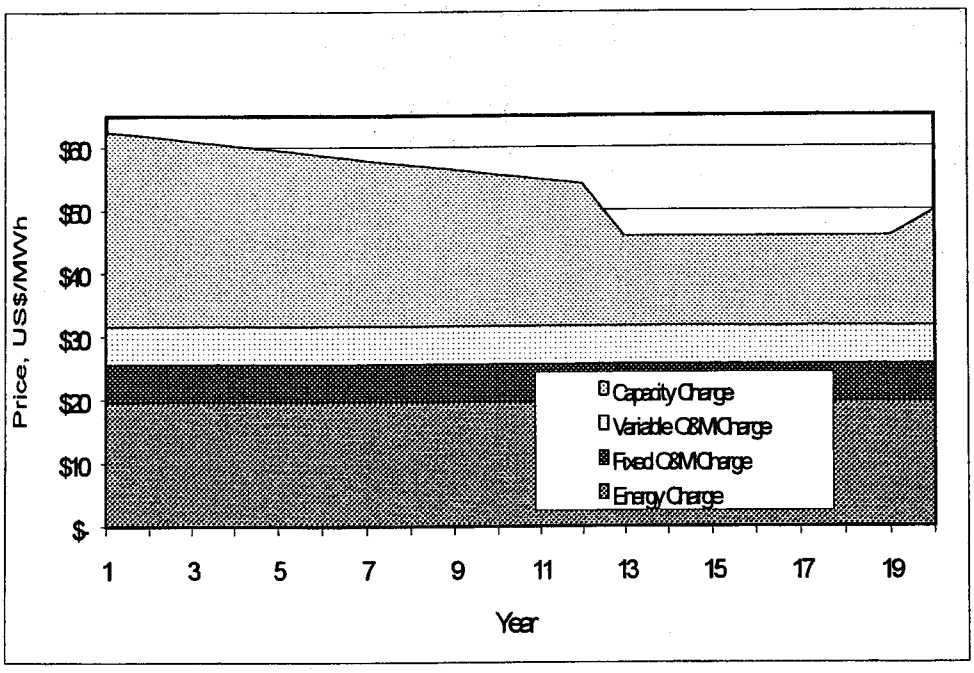
The financial model utilized for the Land based option and presented hereunder considers the Financing Plan 1 option (ECA led). The goal in the model was to establish a minimum debt coverage ratio (DCR) of 1.3 times, a multiple which has been acceptable by most financing sources available for a Senegal power project, and a minimum Internal Rate of

Return to the equity of 23%. This is estimated to be the level of returns that an investor may be willing to achieve under a competitively bid power project in West Africa.

Tariff

The tariff was derived using a traditional two-tiered tariff structure, incorporating a Capacity Charge and Energy Charge component. The Capacity Charge is almost entirely driven by the debt service, with an adjustment every 6 years for the return on equity component. There are numerous ways of developing the total Capacity Charge, and the manner in which the investors will recoup their equity capital through the Capacity Charge. The Model uses a slightly declining equity return component over the 20 year period beginning at US$ 9,200 per MWh per month. This is higher than what is utilized for the Barge based option (Section 10). The resulting tariff on a 20 year average is US$ 53.45/MW. Exhibit 9-3 depicts the tariff profile through the project life.

Exhibit 9-3
Planned Tariff Profile through the Project Life



Equity

The equity amount used in the Land based plant is slightly higher than the Barge option due to the associated risks with an immovable asset. The Debt to equity is thus 70/30.

Debt

As discussed earlier, we assume that an ECA such as the US Exlm Bank will be available to finance this project. Assuming that all costs are eligible, an ECA can provide tenors of up to 14 years. They will generally follow the maximum guidelines set by the OECD and precedents for the host market. The repayment period for the Debt is therefore set for 12 years from completion, already two years longer than the Cap de Biches plant. While the US Exlm Bank operates with exposure fees/premium fees established and paid at financial close and drawdowns, the model applies these fees across the debt period in the form of an annual premium equivalent to an assumed exposure/premium fee (analogous to OPIC or a multilateral). The cost for the debt used in the financial model is 9.5% per annum, fixed.

Project Costs

Total Project Costs inclusive of all soft costs are $74,425,944. The bulk of the cost is the Contractor's Price of $53.5 million, which is inclusive of the offsite costs and contigencies. In addition to the assumed Taxes and Duties of $2.5 million, the remaining $18 million are typical additional costs which occur in a limited recourse financing. Developers will recoup their development costs, and then a fee for the risk taken, the legal fees will be significant, and the costs related to financing (commitment fees, arranging fees, etc.) will result in meaningful soft costs. The bulk of the $18 million however, is due to the accrual of interest during construction (IDC) in the amount of $5.7 million, and the capitalizing of the Debt Service Reserve amount ($4.6 million). The latter can be built-up from project cash flows instead of being capitalized, but this option would require sponsor guarantees of the reserve amount through the construction period. We believe the former is an acceptable option.

Financing and legal fees are based on a percentage of project costs, and on the basis of the existence of project documentation in Senegal. This budget needs to be well managed by all parties involved.

In order to maintain the project costs at a reasonable level, the Model assumes a working capital facility separate from the Project Costs, renewable annually. The amount drawn down from this credit line will be less than $4 million at any point in time.

Depending on the timing these project costs can adjust, even significantly, one way or the other.

Operating Costs: The fuel cost assumed for both the barge and the land based option is $2.70 per MMBtu. The heat rate for the plant is estimated at 7,197.

Income taxes are applied at the rate of 25%. No escalation of any kind is used.

Financial Results

Financial Analysis assumptions and results are summarized in Exhibit 9-4. An IRR of 23.0% is achieved, with a minimum DCR of 1.41. Please refer to Appendix I for the detailed Financial Model printouts.

Conclusion

The most attractive option for financing a new independent power project in Senegal will be a limited recourse project financing. The preliminary financing plan seeks to maximize the participation of "official" sources of financing, such as Export Credit Agencies and Multilateral/Bilateral Institutions. The longer tenors and reasonable interest rates form such sources of financing would result in lower debt service requirements and keep electricity tariffs at as low a level as possible.

The assumptions used, adapted to the Senegalese environment, show that a new power plant has economic viability at reasonable (unescalated) tariffs. A well run competition may result in lower tariffs driven by lower project costs and a lower return on equity target.

Exhibit 9-4
Financial Assumptions and Results Land-Based Plant

GENERAL

Construction Start Date:	01-Jan-99
Commercial Operations:	01-Jan-01
Construction Period (months):	24
Project Life (years):	20
Cycle:	Combined
Net Plant Capacity (MW):	70.9
Steam Capacity (tonnes):	0
Hours of Operation:	7,884
Operating Availability:	90.0%
Exchange Rate (CFA / US$):	

POWER GENERATION

Net Plant Capacity (MW):	70.9
Total Annual Output (MWh/year):	558,976
Net Power Available for Sale (MW):	63.8
Fuel Consumption (10^12 Btu/yr):	4.02
Fuel Price ($/MMBtu):	2.70
Heat Rate (Btu/kWh):	7,197
Diesel Oil Consumption (gallons):	0
Steam Output (tonnes/hour)	
High Pressure:	0
Intermediate Pressure:	0
Low Pressure:	0
Total Annual Steam Output (tons/h):	0

REVENUE

Electricity Tariff ($/MWh):	Year 1
Customer 1:	62.47
Customer 2:	0.00
Customer 3:	0.00

Electricity Sale:	MWh / year	%
Customer 1:	558,976	100.0%
Customer 2:	0	0.0%
Customer 3:	0	0.0%

USES

Specialized Equipment	30,755,000	41.3%
Other Equipment	1,413,000	1.9%
Civil	1,272,000	1.7%
Mechanical	$2,617,000	3.5%
Electrical	$1,521,000	2.0%
Buildings & Structures	426,000	0.6%
Contractor's Soft & Miscellaneous Costs	$7,545,000	10.1%
Engineering & Plant Startup	2,751,000	3.7%
Subtotal - Contractor's Internal Cost	**$48,300,000**	64.9%
Barge	0	0.0%
Tow and Moor At Site	0	0.0%
Contractor's Price	**$48,300,000**	64.9%
Taxes & Duties	$2,415,000	3.2%
Development Fee	$4,000,000	5.4%
High Pressure to Gas Line to Site Boundary	$2,700,000	3.6%
Contingencies	$1,250,000	1.7%
Cool Water Intake Structure & Pipe	$750,000	1.0%
Electrical Sub Station	$1,700,000	2.3%
Financing Fees/Legal Costs:	$3,000,000	4.0%
Working Capital:	$0	0.0%
Debt Service Reserve Fund:	$4,612,850	6.2%
IDC:	$5,698,094	7.7%
TOTAL PROJECT COST:	**$74,425,944**	**100.0%**

RESULTS

Equity IRR	23.0%
Min DSCR	1.41
Avg. DSCR	1.91

DSRF FACTOR

# Months:	6
Factor:	50%

CAPEX

Factor+Duties	*105.00%*
$ per KW	*$1,050*

SOURCES

EQUITY	$22,336,551	30.0%
ECA DEBT	$52,089,393	70.0%
TOTAL	**$74,425,944**	**100.0%**

SECTION 10
THE BARGE-MOUNTED PLANT OPTION

This section summarizes a promising alternative approach for the Senelec IPP that may be attractive for financing and implementation, considering the uncertainty of natural gas supply.

10.1 BACKGROUND

Barge-mounted gas turbine plants are seeing increasing application. Barge-mounted power plants were first developed in small sizes using diesel or gas turbine simple cycle configurations to serve waterfront communities, but more recently have become feasible in larger sizes, and also in gas turbine combined cycle configurations. Westinghouse Power Generation (now Siemens Westinghouse) has pioneered the effort to develop larger frame barge-mounted gas turbine plant concepts.

Exhibit 10-1 presents some of the general advantages and disadvantages of barge mounted power plants.

Exhibit 10-1
Advantages of Barge-Mounted Power Plants

Advantages	Disadvantages
Consistent, high quality fabrication and construction in a controlled "production line" manufacturing process.	Can be more expensive, depending on substructure and harbor/mooring configurations.
Potential to shorten construction time through close monitoring of a fast track schedule.	Most labor to build the plant is provided off-shore, i.e. domestic construction labor is minimized.
Financing is viewed less risky (resource can be repossessed); financing with attractive terms from the U.S. Maritime Administration {MARAD} is available.	Project requires longer tenor to offset the additional cost if economics and tariff have to remain neutral.
Plant can be relocated to exploit new fuel supplies or serve different load center.	

Neighboring Ghana recently signed a turnkey contract with Westinghouse for a 144 MW simple-cycle barge-mounted plant;

Parsons is performing the engineering for this plant, including the barge. Provisions are being made for subsequent conversion to combined cycle operation.

A barge-mounted plant may be slightly more expensive than a land-based plant, assuming that conditions of infrastructure, skilled labor availability, land availability, site access, etc., are reasonable. Generally, if the alternate land-based site is remote, and suffers from a deficiency of the above, or if there is greater risk in financing, and the barge satisfactorily reduces that risk, then it can be significantly more technically and economically attractive than a land-based plant.

The design of a barge plant is similar to a land-based plant, except that more attention must be paid in the design to maintain proper shaft alignment tolerances, especially for the larger rotating equipment. A careful design of the barge insures proper stiffness, and the method for large equipment support to insure this alignment. Other components are simplified to reduce weight and save space, and more shared auxiliary systems are included in the design.

Selected articles on barge-mounted plants are included in Appendix K.

10.2 BASIS OF BARGE-MOUNTED PLANT APPLICATION IN SENEGAL

Senegal is a very appropriate location for a barge-mounted plant application for the following reasons:

- Competitive capital cost,
- Potential short implementation schedule,
- Likelihood of improved financing terms, and
- Plant can be relocated to take advantage of a future gas supply location.

Our concept consists of developing a "barge-mounted" plant that would initially be located near Bel-Air, within the Dakar Port facility. Natural gas sources are being developed at several locations within a 10 km radius of Kayar. However, none of the resources to date have proven sufficient reserves to supply electric generation of greater than 10 MW capacity. The companies exploring for natural gas (Petrosen, Tullow, and partners) are not giving up, and there is an active drilling program in place (see Section 3). The prospect of natural gas development gives hope to the idea of exploiting this natural gas resource for the purpose of power generation in the near future.

It is not necessary to confirm at this time that the barge-mounted plant will be relocated to the Kayar Site. At the time that natural gas reserves are proven, another study will be initiated with the objective of proving feasibility of moving the plant vs. building a separate greenfields plant and retaining the location of the barge plant. As part of this study, the price of natural gas will be negotiated/confirmed.

10.3 FUEL SUPPLY

Initially, the barge plant will be fuelled by natural gas condensate, with diesel backup. The fuel characteristics are presented in Section 3.

Gas condensate will be delivered to the existing Port of Dakar facilities by tanker with a minimum delivery quantity, requiring significant storage. The storage requirement can be significantly reduced if another user, such as one or more of the Caps de Biche plants can utilize/share the gas condensate fuel supply. This will be explored during the detailed design stage.

10.4 PLANT CONFIGURATION

The initial plant consists of a gas turbine combined cycle plant of 74 MWe net power output. A second unit would increase plant output to 148 MWe, when this level of demand materializes. The plant will be barge mounted, with all major components located on a single barge. A second plant would be constructed on a second barge. The barge dimensions, containing the entire Module 1 plant would be approximately 25x100m. In the detail design stage, a more thorough study may indicate that each plant module should be constructed on two smaller barges, instead of a single barge.

Land-based equipment will include electrical tie-ins, long-term fuel storage, fuel delivery, and possibly some water treatment for boiler makeup at the existing Bel-Air plant.

Cooling water intake and discharge systems will be self-contained on the barge. To avoid recirculation, the warm water discharge may be routed to a location away from the intake pipe. This issue will be addressed in the detailed design phase.

10.4.1 Plant Site and General Arrangement

The proposed alternative location for the proposed barge-mounted plant is near the fuel unloading facility in Dakar, and very close to

Senelec's Bel Air generating facility. A plan view of Port Dakar, identifying the proposed site location is shown in Exhibit 10-2.

Dakar's port has more than 9,000 m of quays and 43 berths, of which 40 are suitable for ships of up to 40,000 mt. The port is one of the few in Africa with a floating dry dock, a container terminal, and automated container service. It has a fishing pier with sites reserved exclusively for cold storage and repair and maintenance of fishing fleets. However, overall port charges are high compared with those in Cote d'Ivoire and other regional ports.

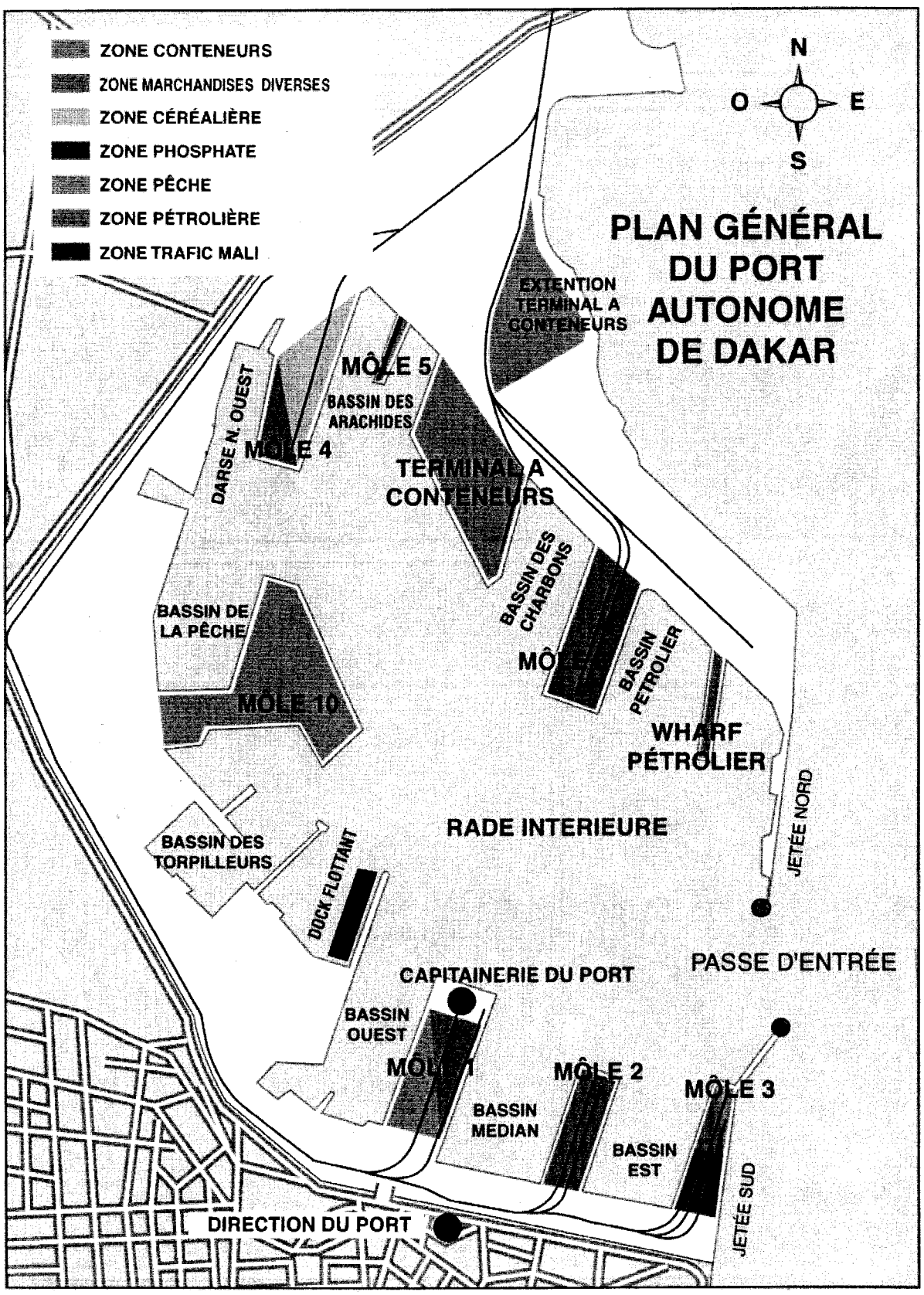
Specifically, the plant will be located in the slip of the abandoned Darse ex-A.C.D. facility, located just west of the Bel-Air water intake/discharge structures. The plant location is shown in Exhibit 10-3, as well as the location of the existing Bel-Air facility. Photos of the proposed slip location are presented in Exhibits 10-4 and 10-5.

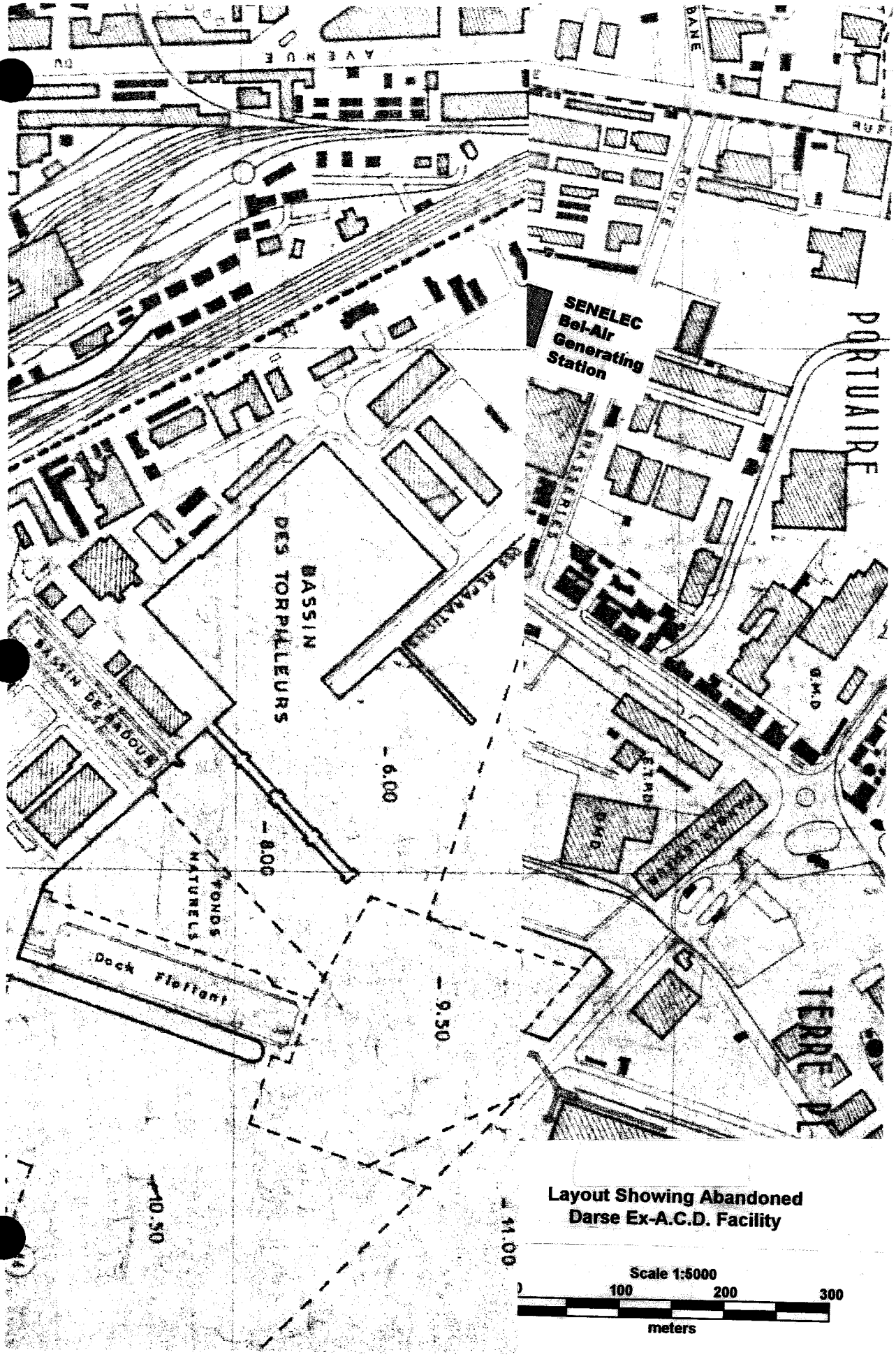
Land-based fuel storage would be required in this congested area. There are several additional options within Port Dakar to be considered in the case that the Darse ex-A.C.D. area is found to be unsuitable.

10.4.2 General Plant Arrangement

The general equipment arrangement on the barge to be docked in the Darse A.C.D. slip is shown in Exhibit 10-6. The gas turbine and steam turbine units are arranged in parallel. The HRSG is located near the barge center to provide good weight distribution. Electrical and other auxiliary equipment are located compactly as shown. The cooling water intake location is shown. Cooling water discharge may be piped some distance from the intake to eliminate recirculation. The final configuration will be developed during the detail design phase.

Exhibit 10-2
Plan View of Port Dakar





Layout Showing Abandoned Darse Ex-A.C.D. Facility

Scale 1:5000

0 100 200 300

meters

Exhibit 10-4
Photograph of Abandoned Darse Ex-A.C.D. Facility, Looking West

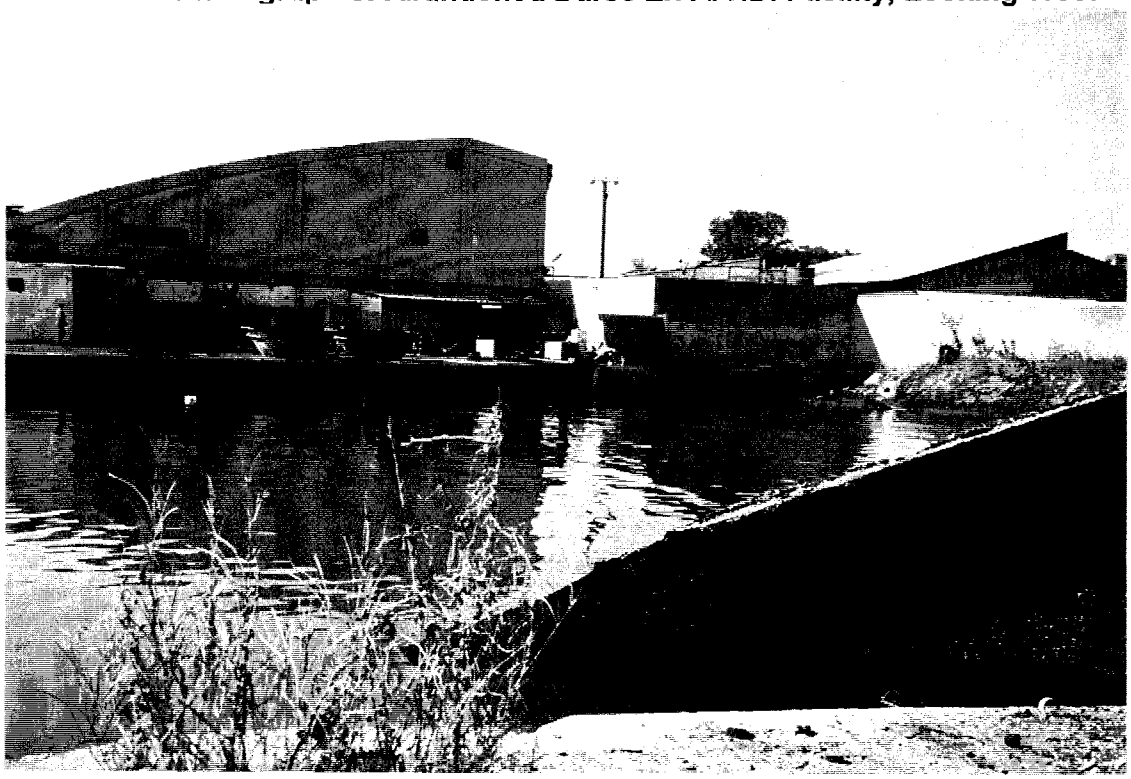
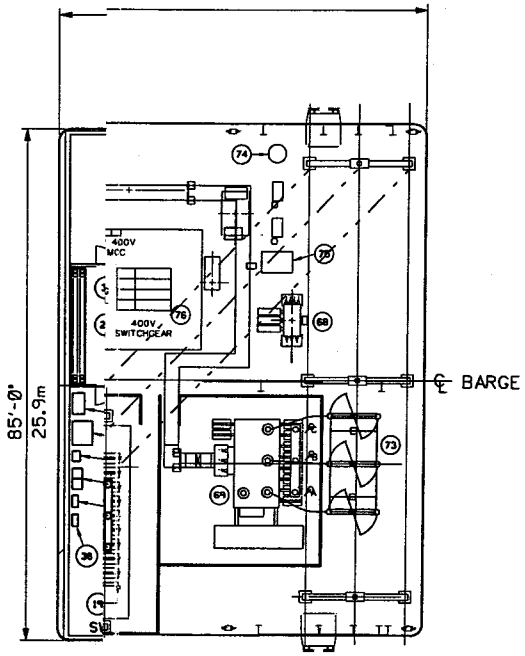


Exhibit 10-5
Photograph of Abandoned Darse Ex-A.C.D. Facility, Looking East



NOTES:

EE

1. HEAT RECOVERY STEAM GENERATOR (HRSG)
2. HRSG BLOWDOWN TANK
3. HRSG HIGH PRESSURE DRUM
4. HRSG LOW PRESSURE DRUM
5. HRSG STACK
6. BOILER FEEDWATER PUMP
7. STEAM TURBINE GENERATOR STEP-UP TRANSFORMER
8. AUXILIARY TRANSFORMER
9. AIR COOLED GENERATOR WITH BRUSHLESS EXCITER
10. SINGLE CASE STEAM TURBINE
11. SCREEN WASH PUMP SKID
12. LUBE OIL SKID
13. STEAM CONDENSER
14. CIRCULATING WATER PUMP
15. CONDENSATE PUMPS
16. AUXILIARY COOLING WATER PUMP
17. NOT USED
18. 6.9 KV SWITCHGEAR
19. 400 V SWITCHGEAR
20. GENERATOR BREAKER
21. VACUUM PRIMING SYSTEM
22. AUXILIARY COOLING WATER HEAD TANK
23. GLAND STEAM SUPPLY SKID
24. GLAND STEAM LEAKOFF CONDENSER SKID
25. AUXILIARY COOLING WATER HEAT EXCHANGERS
26. STEAM JET AIR EJECTORS
27. BATTERY ROOM
28. ELECTRICAL/MECHANICAL WORKSHOP
29. CIRCULATING WATER MECHANICAL FILTRATION AREA
30. EYE WASH & SAFETY SHOWER
31. 125 V BATTERY
32. BATTERY CHARGER
33. UPS SYSTEM
34. UPS ISOLATION TRANSFORMER
35. 125 V D.C. DISTRIBUTION PANEL #1
36. 400 V MOTOR CONTROL CENTER
37. 125 V D.C. DISTRIBUTION PANEL #2
38. 400/230 V DISTRIBUTION PANEL
39. TRAVELING WATER SCREEN DRIVE
40. SEWAGE TANK AND PUMP
41. COMPUTER TYPE RAISED FLOOR SYSTEM
42. SODIUM BISULFITE FEED SYSTEM
43. SODIUM HYPOCHLORITE FEED SYSTEM
44. SAMPLING & ANALYSIS SYSTEM
45. PHOSPHATE SOLUTION FEED SYSTEM
46. OXYGEN SCAVENGER FEED SYSTEM
47. NEUTRALIZING AMINE FEED SYSTEM
48. SODIUM HYPOCHLORITE STORAGE TANK
49. SODIUM BISULFITE STORAGE TANK
50. NOT USED
51. AUXILIARY AIR FAN
52. NOT USED
53. OIL/WATER SEPARATOR AND SLOP TANK PUMP
54. OIL/WATER MONITOR AND PUMP
55. AUTOMATIC BACKWASH STRAINERS
56. COMBUSTION TURBINE
57. REDUCTION GEAR UNIT
58. TURBINE INLET DUCTING
59. TURBINE ROTOR AIR COOLER
60. LUBE OIL COOLER
61. GENERATOR
62. STARTING PACKAGE
63. ELECTRICAL ENCLOSURE/CONTROL PACKAGE
64. SEAL AIR COOLER
65. AUXILIARY LUBE OIL RESERVOIR
66. VAPOR EXTRACTOR
67. SWITCHGEAR
68. AUXILIARY TRANSFORMER
69. MAIN TRANSFORMER
70. FUEL OIL/WATER PURGE
71. SWITCHGEAR BUILDING
72. AIR CONDITIONER
73. DISCONNECT SWITCH
74. COMPRESSED AIR RECEIVER
75. COMPRESSED AIR DRYER
76. STATIC EXCITER ENCLOSURE

Exhibit 10-6

DPU CA

FIRE PROTECTIO
TELEPHONE SERV
TRANSFORMER REL
TRANSFORMER REL
ST REL
ST VOLTAGE

OPERATOR CONSOLE
C.C. BARGE-2 IN C.C
CONTROL ROOM ONL

DISTRIBUTION

REV	DATE	DESCRIPTION	DRAWN	CHECKED	LEAD DESIGNER	ENGINEER	LEAD DISCIP ENGINEER	PROJ ENGR MANAGER	PROJECT MANAGER

STATUS OF DRAWING	DEFINITION	CONSTRUCTION STATUS
PRELIMINARY	REPRESENTS GENERAL DESIGN CONCEPTS BASED ON ASSUMPTIONS. REVIEWED NOT CHECKED.	

DRAWN BY VJB	DATE 02-12-99
CHECKED BY	DATE
LEAD DESIGNER	DATE
ENGINEER	DATE
LEAD DISCIPLINE ENGR.	DATE

PROJECT ENGINEERING MANAGER

PROJECT MANAGER

PARSONS
PARSONS ENERGY & CHEMICALS GROUP INC.
RENDING OFFICE

CLIENT/PROJECT TITLE

U.S.T.D.A.
SENEGAL
COMBINED CYCLE PLANT

BARGE - MOUNTED ALTERNATIVE

SCALE

PARSON'S DWG. NO. BA-1

REV

ARCH | STRUC | ARCH | HVAC | I & C | ELECT | MECH | CIVIL | STRUC | ARCH | HVAC | I & C | ELECT | MECH | CIVIL | STRUC

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10.5 ENVIRONMENTAL CONSIDERATIONS

Environmental regulatory and permitting requirements of the barge plant are expected to be similar to those outlined in Section 7. Additional maritime considerations associated with the port location are expected, but should not be a problem.

10.6 PLANT CAPITAL COST, DESCRIPTION, AND SCHEDULE

The plant will be constructed in a large U.S. port, shipped to Dakar, and made ready for operation within one to two months. The overall schedule could be accomplished in less than 2 years. Following is a brief discussion on capital costs and schedule.

10.6.1 Conceptual Cost Estimate and Assumptions

A conceptual cost estimate has been developed for the initial barge plant in order to demonstrate the cost feasibility of the barge mounted power plant alternative. The Total Project Cost, which is approximately $78 million, includes the project Capital Costs, debt service reserve, working capital, allowances for taxes and duties and the project Development Fee. Excluded from this estimate are:

- Fuel & Chemical Inventory
- Permits & Licenses

Costs are expressed in 3rd quarter 1998 US dollars, and exclude escalation.

The conceptual costs are based on actual cost information derived from previous barge projects, published reports, and historical data from other barge plant studies and evaluations. The estimate provides an indicative range of cost and is representative of results to be expected from a lump sum turnkey bid solicitation.

Contingency is omitted from the estimate for all cost categories, with the exception of the Off-Site costs, because of the conceptual nature of the project scope. Accuracy falls within a range of ± 25%.

The estimate is based on procurement of the following major equipment components:

- One (1) Westinghouse 251B11 Gas Turbine,
- One (1) Steam Turbine Generator
- One (1) HRSG

The barge alternative's Capital Cost Summary is presented in Exhibit 10-7.

Exhibit 10-7
Capital Cost Estimate Summary for Barge Mounted Power Plant

Cost Component		Estimated Cost, $US
I	Specialized Equipment	28,000,000
II	Other Equipment	2,150,000
III	Civil	2,500,000
IV	Mechanical	
V	Electrical	
VI	Buildings & Structures	12,000,000
VIII	Contractor's Soft & Miscellaneous Costs	
VII	Engineering & Plant Startup	6,065,000
	Subtotal - Contractor's Internal Cost	50,715,000
Barge		6,000,000
Tow and Moor At Site		1,500,000
Contractor's Price		**$58,215,000**
Net Plant Output (ISO)		75 MW
Cost per kW - Contractor's		$776

There are several basic differences between the construction of a barge mounted power plant and a conventional land-based unit that have an effect on the project costs. For example, costs for the civil work for a land-based unit, consisting generally of site preparation and equipment foundations, can be said to be significantly lower than for a barge mounted plant, since, for comparative purposes, the construction cost of the barge should be considered as a civil element for the barge mounted power plant. The cost for a barge may range from US$6 to US$9 million dollars, whereas costs associated with conventional land-based site preparation and equipment foundations may fall within a cost range of US$1.5 - US$2.5 million. In contrast, the total civil cost for the barge plant, inclusive of the cost of the barge, is approximately US$8.5 million.

Engineering is another area where costs related to a barge unit will exceed those of a land-based unit, due to the inherent complexity of the barge installation.

The efficiencies and schedule control derived from construction under controlled conditions are significant benefits that should at least partially off-set the cost-additive factors. Additional financing benefits are discussed later.

The conceptual cost estimate for the barge-mounted plant assumes that the erection of the plant will take place at a shipyard on the U.S. Gulf Coast. The advantages of erecting the equipment at a U.S. (or similarly capable) shipyard are that there will be access to a skilled construction labor force, and a highly developed infrastructure to support equipment procurement logistics. In addition, technical pre-testing can take place in the shipyard to minimize start-up costs at the site. These factors will work favorably to reduce the overall project schedule. It is recognized that erection in the U.S. will need to be evaluated in more detail during the bidding process.

Site development costs, under most circumstances - exclusive of the barge - will be marginal for a barge mounted facility. Land-based equipment for the proposed alternative will be limited to:

- mechanical and electrical tie-ins,
- long-term fuel storage,
- fuel delivery equipment,
- gangway access, and
- firewater storage and demineralized water storage tanks.

The barge will be located within 500 meters of the existing Bel-Air switchyard. An allowance for system connections and modifications to the existing switchyard is included in the Off-Site cost estimate. Actual costs will depend on the disposition (retirement) of the Bel-Air existing generating facilities.

The foundations for the barge mounted equipment, rather than being reinforced concrete like a land-based plant, will be structural steel. The foundations will be supported by a series of springs to isolate the equipment from the longitudinal bending of the barge, due to water and air temperature differentials. A naval architect will determine the size of the barge and the distribution of the loads on the barge infrastructure, including operating loads and equipment loads. Storm loads and transportation tow loads will also be determined.

Off Site Costs associated with the barge should be significantly lower than for the Kayar unit, primarily due to fuel and site location. An allowance of US$1,650,000 has been estimated for Off Site to account for system connections and/or modifications to the existing substation; anchorage; roads and perimeter security, and a contingency allowance for elements of scope that are not foreseen at this time. The most critical site-related consideration will be the site soil conditions, which sometimes present significant cost risks relative to the sinking of fixed mooring anchors and piling for the barge. For this assessment, no abnormal conditions are considered to exist at the Dakar Port facility

location. This "established" port location should actually reduce the risk of excessive costs associated with mooring of the barge.

It is assumed that a new barge will be procured. Where the barge will be built is undetermined, but construction of the barge must be accomplished in a shipyard that has capabilities that will not restrict the design of the power plant facilities. As previously stated, the barge dimensions, containing the entire plant, would be approximately 25x100m. In addition to the equipment, deck houses are included on the barge to provide limited personnel facilities, control rooms and electrical switchgear. It is assumed that prefabricated modular buildings will be used, if feasible. Since the Bel-Air facility is nearby, some plant services can potentially be accommodated at that facility.

A combination of corrosion allowance, cathodic protection, and a paint system will be specified to minimize or eliminate the need for dry dock maintenance of the barge.

It is likely that the barge will be "dry-towed" to Port of Dakar, unloaded and then towed by tugs to its final destination. It will then be securely moored, and all necessary connections made.

10.6.2 Project Schedule

The barge-mounted plant should be able to improve upon the land-based project schedule presented in Section 9. Time should be save on all aspects the schedule, including time to financial close, fabrication and construction. The final result should be a savings of from three to six months, when compared to the land-based project. A schedule for the barge-mounted plant is presented at the end of this section.

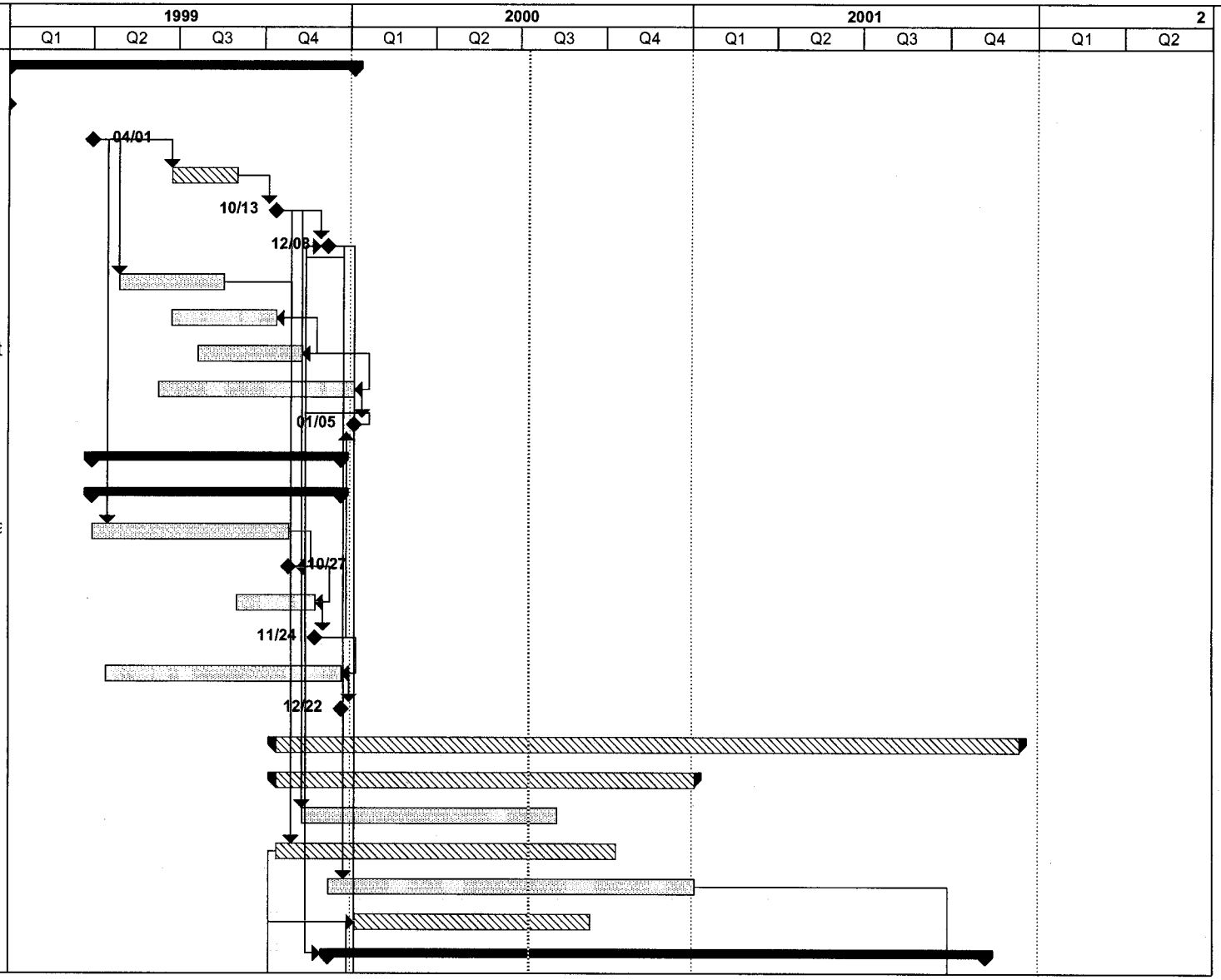
10.7 APPROACH TO FINANCING

A preliminary assessment of financing potential was conducted, and is presented in the following two sections. Refer to Section 9 for a full discussion of financing options for the land-based facility.

10.7.1 Capital Requirements

A conceptual Total Project Cost summary for the first barge mounted power plant is provided in Exhibit 10-8. In addition to the Capital Costs, the TPC includes Taxes and Duties, Off Site Costs, Development Fees and other project indirect costs.

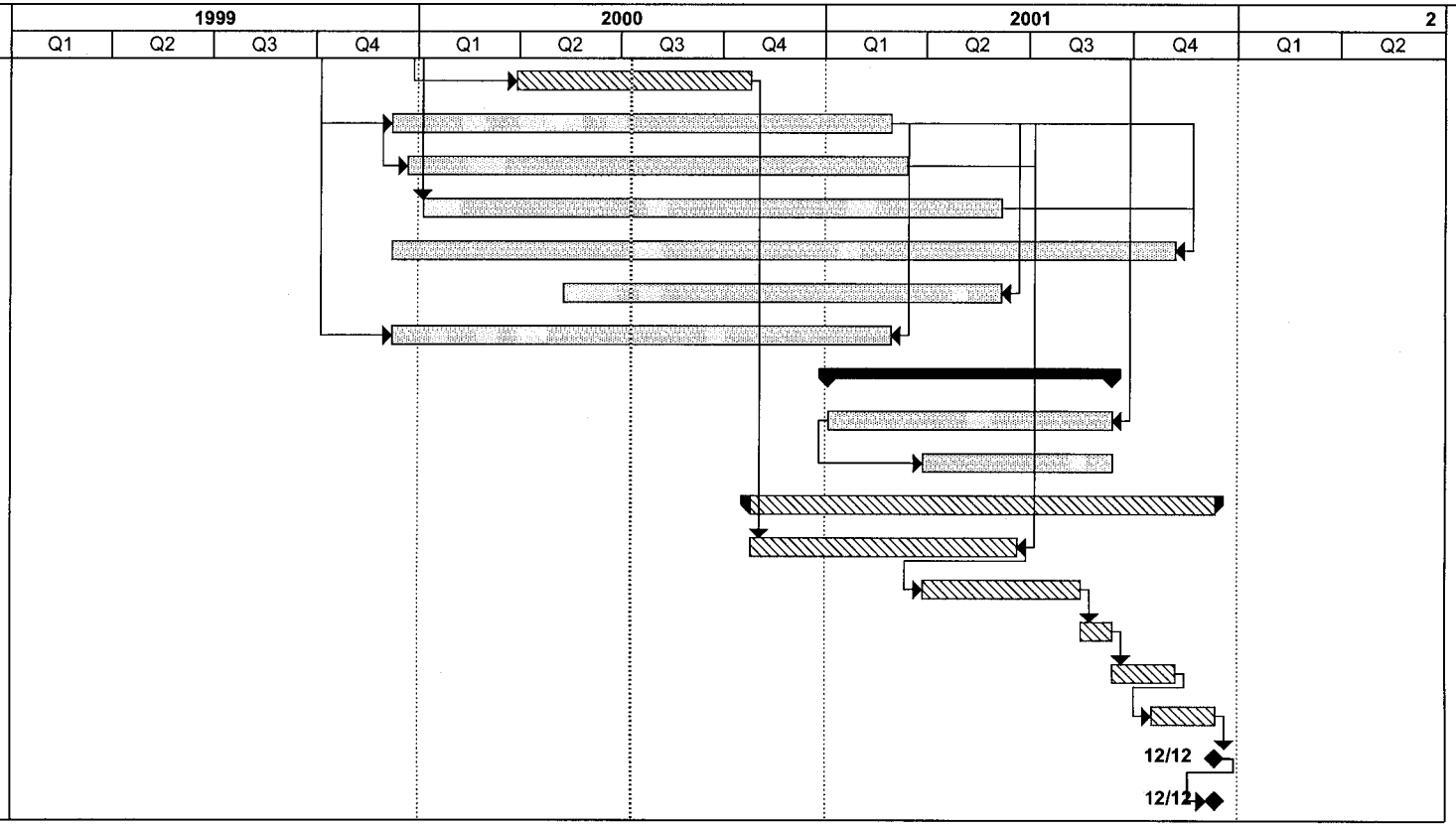
ID	Task Name
1	**COMMERCIAL ASPECTS**
2	***Project Commercial Development***
3	Initiate Final Project Development
4	EPC Development & Negotiation
5	EPC Award
6	Notice to Proceed - Full (EPC)
7	Shareholder's Documents
8	Concession Documents & Approvals
9	Prepare/Negotiate Comm'l Document
10	Project Funding & Finance
11	Financial Close
12	**ENVIRONMENTAL PROCESS**
13	**Environmental Impact Assessment**
14	Prepare Environmental Documenta
15	Issue EIA Document
16	Ministry Review
17	EIA Approval
18	LP (Lic. to Proceed) Development
19	LP (Lic. to Proceed) Issued
20	**IMPLEMENTATION**
21	**Engineering/Design**
22	Civil
23	Mechanical
24	Electrical / I & C
25	Naval
26	**Procurement**



Project: Senelec Combined Cycle Implementation Schedule
Date: January 1999
Parsons and Taylor-DeJongh

Task
Progress
Milestone
Summary
Rolled Up Task
Rolled Up Milestone
Rolled Up Progress
Critical

ID	Task Name
27	Barge/Structural Steel
28	Gas Turbine Generator
29	Heat Recovery Steam Generator
30	Steam Turbine Generator
31	Electrical
32	Instrumentation & Controls
33	Balance of Plant
34	**Land Based Infrastructure**
35	Transmission/Distribution
36	Buildings
37	**Construction/Startup**
38	Shipyard Construction/Erection
39	Shipyard Equipment Testing
40	Transporation of Barge
41	Barge/Site Interface
42	Startup and Testing at Site
43	**LO (Lic. to Operate)**
44	**Commercial Operation Date**



Project: Senelec Combined Cycle Implementation Schedule
Date: January 1999
Parsons and Taylor-DeJongh

Task		Summary		Rolled Up Progress	
Progress		Rolled Up Task		Critical	
Milestone	◆	Rolled Up Milestone	◇		

location. This "established" port location should actually reduce the risk of excessive costs associated with mooring of the barge.

It is assumed that a new barge will be procured. Where the barge will be built is undetermined, but construction of the barge must be accomplished in a shipyard that has capabilities that will not restrict the design of the power plant facilities. As previously stated, the barge dimensions, containing the entire plant, would be approximately 25x100m. In addition to the equipment, deck houses are included on the barge to provide limited personnel facilities, control rooms and electrical switchgear. It is assumed that prefabricated modular buildings will be used, if feasible. Since the Bel-Air facility is nearby, some plant services can potentially be accommodated at that facility.

A combination of corrosion allowance, cathodic protection, and a paint system will be specified to minimize or eliminate the need for dry dock maintenance of the barge.

It is likely that the barge will be "dry-towed" to Port of Dakar, unloaded and then towed by tugs to its final destination. It will then be securely moored, and all necessary connections made.

10.6.2 Project Schedule

The barge-mounted plant should be able to improve upon the land-based project schedule presented in Section 9. Time should be save on all aspects the schedule, including time to financial close, fabrication and construction. The final result should be a savings of from three to six months, when compared to the land-based project.

10.7 APPROACH TO FINANCING

A preliminary assessment of financing potential was conducted, and is presented in the following two sections. Refer to Section 9 for a full discussion of financing options for the land-based facility.

10.7.1 Capital Requirements

A conceptual Total Project Cost summary for the first barge mounted power plant is provided in Exhibit 10-8. In addition to the Capital Costs, the TPC includes Taxes and Duties, Off Site Costs, Development Fees and other project indirect costs.

Exhibit 10-8
Project Cost Summary for Barge-Mounted Plant

USES

Specialized Equipment	$	28,000,000	35.7%
Other Equipment	$	2,150,000	2.7%
Civil	$	2,500,000	3.2%
Buildings & Structures	**$**	**12,000,000**	15.3%
Engineering & Plant Startup	$	6,065,000	7.7%
Subtotal - Contractor's Internal Cost	**$**	**50,715,000**	**64.6%**
Barge	$	6,000,000	7.6%
Tow and Moor At Site	$	1,500,000	1.9%
Contractor's Price	**$**	**58,215,000**	**74.1%**
Taxes & Duties	$	2,535,000	3.2%
Development Fee	$	4,000,000	5.1%
Financing Fees/Legal Costs:	$	2,500,000	3.2%
Debt Service Reserve Fund:	$	4,874,496	6.2%
IDC:	$	6,415,677	8.2%
TOTAL PROJECT COST:	**$**	**78,540,173**	**100.0%**

SOURCES

Equity	$	19,632,288	25.0%
ECA Debt	$	58,907,885	75.0%
TOTAL	**$**	**78,540,173**	**100.0%**

10.7.2 Financing Considerations

The barge project is most suitable to consider the advantages offered by MARAD, and is referred to in Exhibit 10-10 as ECA in the "Sources of Financing." The Maritime Administration of the Department of Transportation (MARAD) is a US government agency that manages a "Federal Ship Financing Program". The program, known as the Title XI Program, was established pursuant to Title XI of the Merchant Marine Act of 1936 and provides for a full faith and credit guarantee by the US Government of debt obligations issued by U.S. or foreign shipowners for the purpose of financing or refinancing US or export vessels constructed in US shipyards. Vessels eligible for Title XI assistance generally include commercial vessels such as passenger, bulk, container, cargo, tankers, tugs, towboats, barges, dredges, oceanographic research, floating power barges, offshore oil rigs and support vessels, and floating drydocks. The program is administered by the Secretary of Transportation acting by and through the Maritime Administrator. Since this is a guarantee program, funds for the guaranteed debt obligations are obtained in the private sector.

The shipowner or shipyard must meet certain financial requirements with respect to working capital and net worth, both of which are based on such factors as the amount of the guaranteed obligations, the shipowner's or shipyard's financial strength, intended employment of the vessels, creditworthiness of the applicant and export country, etc. These factors also affect the terms of the MARAD guarantee, continuing Title XI financial covenants, guarantee fees, etc. All guarantees under this Program must be determined by the Secretary to be "economically sound."

Amount Guaranteed

The upper limit on the guarantee is 87.5% of the cost. The amount of the obligations guaranteed by the Government is based on the "actual cost" of the vessels as determined by the Secretary. The actual cost of a vessel generally includes those items which would normally be capitalized as vessel costs under usual accounting practices, such as the cost of construction, reconstruction, or reconditioning (including designing, inspection, outfitting and equipping) of the vessel, together with construction period interest and the guarantee fee. Items of actual cost must be determined to be "fair and reasonable" by the Secretary. Some costs are excluded from actual cost (although sometimes considered capitalizable costs) such as legal and accounting fees, printing costs, vessel insurance and underwriting fees, and any interest on borrowings for the shipowner's equity in the vessels.

A review of MARAD's financings shows that many projects have been financed in excess of 80% of Project Cost.

Amortization and Interest Rates

The maximum guarantee period is the lesser of 25 years or the remaining economic life of the vessel, as determined by the Secretary. Amortization in equal payments of principal is usually required; however, other amortization methods such as a level debt (equal payments of principal and interest) may be approved if sufficient security is offered such as long term charters, reduction of the amount of guarantee and/or length of guarantee period. What is virtually absolute is that MARAD will match the US EXIM Bank's potential tenor.

The interest rate of the obligations guaranteed is determined by the private sector. The rate must be determined to be "fair and reasonable" by the Secretary. Historically, MARAD has approved interest rates fixed for the financing period. However, recently MARAD has approved floating interest rates with certain restrictions. Interest rates are similar to US EXIM Bank.

Fees

There are three standard fees associated with MARAD financing: filing fee, investigative fee, and a guarantee fee. The applicant must pay a non-refundable filing fee of $5,000 when the application is filed. Prior to issuance of the letter commitment, the applicant must pay an investigation fee of ½ of one percent on obligations to be issued up to and including $10,000,000 plus 1/8 of one percent on all obligations to be issued in excess of $10,000,000. The $5,000 filing fee previously paid upon filing the original application will be credited against the investigation fee.

The guarantee fee is calculated by (1) determining the amount of obligations outstanding during each year of the financing and multiplying that amount by the guarantee fee rate applicable to the project and (2) applying a present value analysis to the amount calculated in (1) above. The guarantee fee rate is generally based on a ratio of net worth to long-term debt of the shipowner or shipyard. The rate is (1) between ½ of one percent to one percent for the period after vessel delivery and (2) between ¼ to ½ of one-percent prior to vessel delivery. Amounts on deposit for the vessel in an escrow fund held pursuant to Title XI are excluded in the computation of this fee.

This program is very similar to the US EXIM Bank as it provides US government backed guarantees for the financing of ships built in the United States. It has financed several power barges in the last few years, including in difficult markets such as Pakistan. The barges are constructed in US Shipyards, and typically have mostly US made equipment. MARAD makes allowances for foreign equipment when such equipment can be proven to be unique, or available in times and prices which are critical to the project's economics, although this decision is very subjective. Nevertheless, the power barge industry has evolved considerably and MARAD has helped promote it for various successful developers/constructors.

Obviously MARAD is only suitable to Senelec if the new project is barge-mounted. Typically, as stated earlier, these barges can be more costly than land-based oil or gas fired projects, yet MARAD's financing terms, if generous on tenor, could nullify the cost advantage of other designs. The cost of processing the application is very low as compared to any other financing source.

Nevertheless, if MARAD declined the project, the same financing sources discussed in Section 9 are available to a barge-mounted power plant.

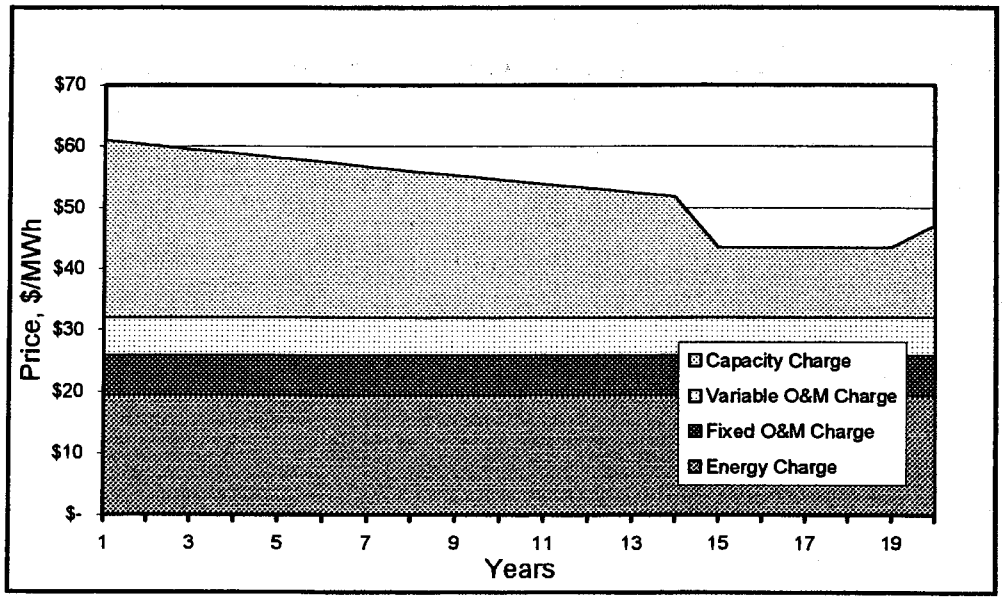
10.7.3 Financial Analysis and Comparison

The same financial model utilized in Section 9 for the Land based option was used for the Barge. The goal was to establish a minimum debt coverage ratio (DCR) of 1.3 times, a multiple which has been acceptable by most financing sources available for a Senegal power project, and a minimum Internal Rate of Return to the equity of 23%. This is estimated to be the type of returns which an investor may be willing to achieve under a competitively bid power project in West Africa.

Tariff

The tariff was derived using a traditional two-tiered tariff structure, incorporating a Capacity Charge and Energy Charge component. The Capacity Charge is almost entirely driven by the debt service, with an adjustment every 5 years or so for the return on equity component. There are numerous ways of developing the total Capacity Charge, and the manner in which the investors will recoup their equity capital through the Capacity Charge. The Model uses a slightly declining equity return component over the 20 year period beginning with $ 8,760 per MWh per month. This is less than what is required for the Land based option. The resulting tariff on a 20 year average is $ 55.64 per MWh. Exhibit 10-9 depicts the tariff profile.

Exhibit 10-9
Tariff Profile for Barge-Mounted Plant



Equity

The equity amount used in the Barge is slightly less than in the Land based on a percentage of project cost basis. The reason for this

assumption is based upon the attractiveness to lenders of the Barge option, and the ability to relocate the asset under most circumstances. The Debt to equity is thus 75/25 for the Barge versus, 70/30 for the Land based plant.

Debt

As discussed earlier, we assume that MARAD will be available to finance this project. Assuming that all costs are eligible, and that the plant and barge are constructed with high quality components for longer life, MARAD can provide tenors of up to 25 years. They will generally follow the maximum guidelines set by the OECD and governing the Export Credit Agencies. The repayment period for the Debt is therefore set for 14 years from completion. While MARAD operates similar to the US Export Import Bank with exposure fees/premium fees established and paid at financial close and drawdowns, the model applies these fees across the debt period in the form of an annual premium equivalent to an assumed exposure/premium fee. The cost for the debt used in the financial model is 9.5% per annum, fixed.

Project Costs

Total Project Costs inclusive of all soft costs are $ 78,540,173. The bulk of the cost is the Contractor's Price of $ 58 million, which is inclusive of the barge's cost of $ 6 million, and the towing/mooring costs of $ 1.5 million. In addition to the assumed Taxes and Duties of $ 2.5 million, the remaining $ 18 million are typical additional costs which occur in a limited recourse financing. Developers will recoup their development costs, and then a fee for the risk taken, the legal fees will be significant, and the costs related to financing (commitment fees, arranging fees, etc.) will result in meaningful "soft" costs. The bulk of the $ 18 million however, is due to the accrual of interest during construction (IDC) in the amount of $ 6.5 million, and the capitalizing of the Debt Service Reserve amount. The latter can be built-up from project cash flows instead of being capitalized, but this option would require sponsor guarantees of the reserve amount through the construction period. We believe the former is an acceptable option.

Financing and legal costs are expected to be slightly less than the land based option due to the MARAD financing option (a less costly process), and the reduced need for local construction efforts. These fees are based on a percentage of project costs, and on the basis of the existence of project documentation in Senegal. This budget needs to be well managed by all parties involved.

In order to maintain reasonable project costs, the Model assumes a working capital facility separate from the Project Costs, renewable

annually. The amount drawn down from this credit line will be less than $4 million at any point in time.

These total costs are very competitive with the Land Based option due to the reduced off-site costs (a difference of $4 million). Depending on the timing these project costs can adjust, even significantly, one way or the other.

Operating Costs

The fuel cost assumed for both the barge and the land based option is $2.70 per MMBtu. The heat rate for the barge is slightly less at 7,175.

Income taxes are applied at the rate of 25%. No escalation of any kind is used.

Financial Results

The assumptions made for the Barge (please refer to the Assumptions page in the Model included in Appendix I), result in an IRR of 23.0%, with a minimum DCR of 1.35 (average 1.77). The tariff required to generate these financial results begins at $ 64.50 per MW, reducing to $59.90 halfway through the debt period, and following the debt period resulting in $45.90 per MW. This is almost identical to the land based plant. Detailed model results are presented in Appendix I.

Conclusion

The assumptions used, adapted to the Senegalese environment, show that a barge plant is also an option that has economic viability at reasonable (unescalated) tariffs. A well run competition may result in lower tariffs driven by lower project costs and a lower return on equity target.

10.8 RECOMMENDATIONS

If proven gas reserves were made available to the project, it is clear that the base analysis conducted in this feasibility study, including the selection and development of the Kayar site, would be viable. Considering the following:

- the gas reserve and supply is not proven,
- natural gas exploration continues with hope of finding large supplies,
- electric power is needed quickly in Senegal to support growing and pent-up demand, and

- electric generating capacity is needed to replace aging and obsolete facilities;

Senegal may be a very appropriate barge-mounted plant application. In addition, the barge-mounted plant features:

- Competitive capital cost,
- Potential short implementation schedule,
- Better financing terms, and
- Possibility of relocation to Kayar or other suitable site near a producing gas supply location.

These conditions further underscore the attractiveness of barge-mounted plant as a viable alternative for Senegal. The preferred location is in the Port of Dakar.

If Senelec desires to pursue a barge-mounted option, the following recommendations are offered:

1. Develop a tender document sent to a short list of medium-sized international bidders that includes this feasibility study, and specifies clearly:
   - Plant location;
   - Configuration, i.e., can be moved to another location (barge-mounted);
   - Fuel requirements (initial gas condensate/diesel, but equipped for, or convertible to, natural gas);
   - Performance requirements;
   - Emission limits; and
   - Tariff requirements;

   as well as schedule and all terms and conditions. Tender should request a development plan that includes sources of financing, contract/permit development, and scenarios to exploit future gas development. It should also allow the bidder to propose an alternate plan.

2. Develop a preliminary agreement with the Port of Dakar to secure an option for the recommended barge location, and include this commitment in the Tender Document.

3. Develop preliminary approvals from the environmental authorities, and include these approvals in the Tender Document.

APPENDICES

Appendix A: .....Project Document List

Appendix B: .....Parsons' Generation Planning Model Input And Assumptions Summary

Appendix C: ..... Heat Balances

Appendix D: .....Vendor Correspondence

Appendix E: Selected ABB GT8C Reference Guide Information

Appendix F: ..... Conceptual Design Equipment List

Appendix G: .....Selected Site Background Documents

Appendix H: ....Selected Barge Mounted Power Plant Articles

Appendix I: .....Financial Analysis Details

Appendix A: Project Document List

During the course of the project, a document log was created. All project documents received by Parsons, excluding routine correspondences, were recorded in this list.

SENELEC DOCUMENT LIST

No.	Date Rec'd	Title	Comment
		General	
G1e	4/96	Parsons Scope of Work	
G2e	4/96	ENPRO Mission Report	Provided w/ RFP. Good overall.
G3ef	8/96	Parsons Data Request	English and French
G4ef	8/96	SENELEC Long Term Generation Plan, September 1994.	
G5ef	8/96	SENELEC Long Term Generation Plan, 1996-2010, revised, April 1996.	
G6f-a G6f-b	8/96 10/97	a. Transmission Map, Senegal (large) b. Tobene - Touba - Kaolack 225 kV project Map	Large rolled color. Recent changes indicated. b. 225 kV map dated 9/97
G7f	8/96	Transmission Map, Senegal (small)	(8-1/2 x 11, black & white)
G8e	12/96	"Feasibility Study on Development of Electric PowerSystem in Dakar Area," EPDC, Japan.	Issued 10/95. Good summary of system, costs, reliability, etc.
G9e	12/96	"Pre-Feasibility Study on Project for Construction of Diesel Power Plant at Tobene," EPDC, Japan.	Issued March 1993. Good approach to evaluation of the two candidate sites.
G10e	1/97	Senelec-GPU Partnership scope	Contact: Robert Fullager, GPU Int'l
G11f	1/97	Senelec Production Report - 1995	Prepared for Greenwich Turbines
G12f	1/97	Senelec Production Report - Dec. 1996	Prepared for Greenwich Turbines
G13f	1/97	Maps (2): Roads, West and Central	Two maps, color.
G14f	1/97	Map: Theis Region	Color.
G15e	2/17/97	Map: Gas lines relative to 90 and 220 kV lines	
G16f	2/17/97	Peat: MC-W Final Report on potential of peat development, conceptual des., etc., Dec. 1983	German company, divided into 4 bound documents.
G17f	2/17/97	Peat: Evaluation of reserves, quality, etc., Dec 1983.	
G18f	4/24/97	Gas Supply: Newspaper article + some facts	From EMSI
G19f G19e	7/97 9/97	Master Plan- Provisional: April 1997	
		Engineering Data	
T1f	8/96	Transmission System Information Package	Several pages, line diagrams.
T2f	8/96	Map indicating Ndiékhirat site	Small.
T3f	8/96	Small Caps de Biches site plan	
T4f	8/96	Caps de Biches "brochure" indicating various plant specs, history, etc.	Big foldout with little cross secions, technical info.
T5f	8/96	Caps de Biches Organization Chart	
T6e	10/96	Greenwich Turbine System Spec.	by Parsons Power-Boston

No.	Date Rec'd	Title	Comment
T7f	1/97	Plant production summary, 31 Dec 1996	One page summary
T8f	1/97	Senelec production summary, 1990-95	Shows fuel use, usage by customer class (voltage).
T9f	1/97	Senelec production summary, 1969-93	
T10f	1/97	Senelec production 31 Dec 1991, and comparison 1989 to 1990, 1990 to 1991	
T11f	1/97	Senelec production 31 Dec 1994, and comparison 1992 to 1993, 1993 to 1994	Various comparisons of production by customer class.
T12f	1/97	Typical heavy fuel analysis from 21 Jan 1997	Quality now better controlled
T13f	1/97	Bexcom weekly oil analyses vs. spec.	28/6/96 to 11/10/96
T14f	4/97	Impedances, specific energy consumptions, fuel consumption, and emission levels	April 17 1997 Letter from Mr. Fall to Mr. Rubow.
T15f	4/24/97	Generator ratings for Senelec machines	
T16f	10/97	Substation Schematics	a) Cap des Biches b) Theis/Thiona c) Hann
T17f-a T17f-b	10/97 10/97	a. Updated Heavy Oil Fuel Price - Hand written. b. 1997 Fuel Price Information	a) Hand written notes from Mr. Fall.
		Financial/Cost Data	
F1f	8/96	Tariff Report for industrial users, 15 Nov 1986	Law specifying the price of electricity.
F2f	1/97	Financial Projections	Tariffs, fuel prices, etc. 13 pg
F3f	1/97	23 MWe Diesel Capital Cost Estimate	From ongoing project (need more detail).
F4e	10/97	Draft GTi Dakar, LTD. Information Memorandum	Confidential. Stamped 5/3/97. Many nos. are outdated. For Info Only.
		Environment Related Data	
E1f	1/97	Environmental Summary Document	Description of application of environmental laws in Senegal.
E2f	1/97	Environmental Decree 62-0297, 11 Aug 1962	Pertains to dangerous or unsanitary facilities.
E3f	1/97	Environmental Decree 64-46, 17 Jun 1964. Also 64-573 & 64-574, 30 Jul 1964.	Pertains to National domain.
E4f	1/97	Environmental Decree 83-05, 28 Jan 1983	Environmental code. Provides authority, but no regulations/limits. These are now being established.
E5f	1/97	Environmental Law 83-71, 5 Jul 1983	Hygiene code.
E6f	1/97	Environmental Law 88-05, 20 Jun 1988	Urban Code.
E7f	1/97	Environmental Law 88-06, 26 Aug 1988	Mining code.

SENELEC DOCUMENT LIST

No.	Date Rec'd	Title	Comment
E8f	1/97	Environmental Law 89-907, 5 Aug 1989	Mining code (refers to above).
E9f	1/97	Environmental Law 93-06, 4 Feb 1993	Forestry code.
E10f	1/97	Environmental Decree 95-357, 11 Apr 1995	Forestry code (refers to above).
E11f	1/97	Draft Environmental Input from EMSI	Outline of Environmental Impact report.
E12f	1/97	Climate Data (temps, humidities by month)	Years 1961-1990, Dakar & Theis Regions.
E13f	1/97	Map: "Carte Geotechnique de Dakar," Par H. Chatelet,	Report on terrain data and foundation req'ts (old). Oversize
E14f	1/97	Map: "Carte Geologique du Senegal," Service des Mines et de la Geologie, BRGM, 1962.	Geology description. Oversize.
E15f	1/97	Map: "Carte Morphologique du Subatratum"	Near Dakar, shows substrata cross section.
E16f	1/97	Map: "Carte Geotechnique de la Presqu'ile de Dakar"	Near Dakar, shows favorable construction zones.
E17f	1/97	Map: "Carte Geotechnique de la Presqu'ile de Dakar"	Near Dakar, shows test locations.
E18f	1/97	Maps (4): Geological Maps	Rolled. Color.
E19f	1/97	Maps (2): Geological Survey (1:2000)	Rolled. B&W. Shows area near Caps de Biche, probably Ndiak Hirates.
E20f	2/17/97	Map: Ocean depths around Senegal	Some accompanying text
E21f	2/17/97	Maps (6): Characterization of peat deposits	As seen in CTS offices.
		Country General Information	
C1e	8/96	Tourist Map	

Appendix B: Parsons' Generation Planning Model Input and Assumptions Summary

GENERATION PLANNING MODEL INPUT AND ASSUMPTIONS SUMMARY

This document summarizes the Parsons Power Generation Planning model inputs and assumptions. The model is based on information received from SENELEC through many documents and correspondences. The modeling was performed with the ELFIN computer code, a product of the Environmental Defense Fund.

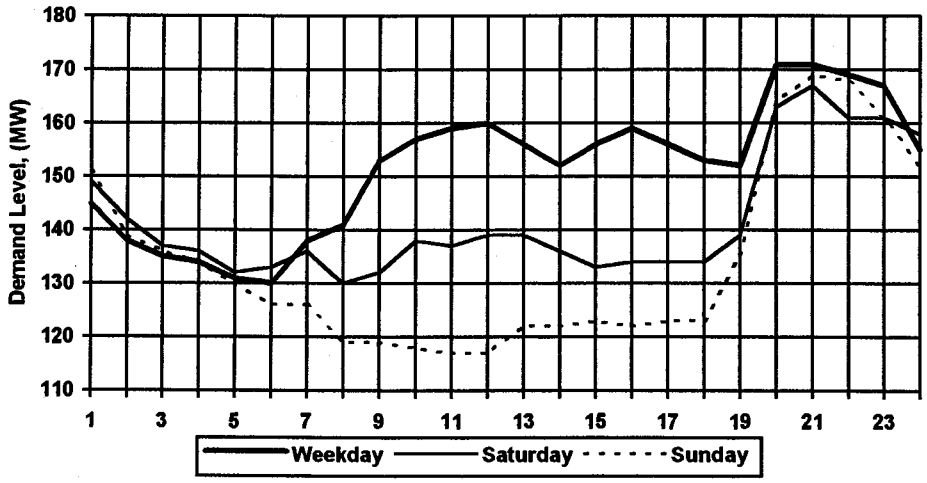
The study period for the model is 1998 to 2020, with an extension period to 2036.

1.0 DEMAND

The net production demand is estimated in the model as the sales load divided by the T&D efficiency, both of which are provided below.

1.1 Sales

Hourly load data has been entered into the model for 12 typical weeks, one for each month. Each week is characterized by 3 typical days representing the weekdays, Saturday and Sunday. This data is based on the hourly load data presented for 1996 in a 1996 generation planning report.[1] A typical load shape for the peak month, October (1996), is presented in the following figure.



The ELFIN Model adjusts this 1996 load shape data for the projected energy consumption and peak Megawatt level.

The anticipated growth of the annual energy sales as presented in GWh and % growth is given below for three scenarios: Expected, High, and Low Demands

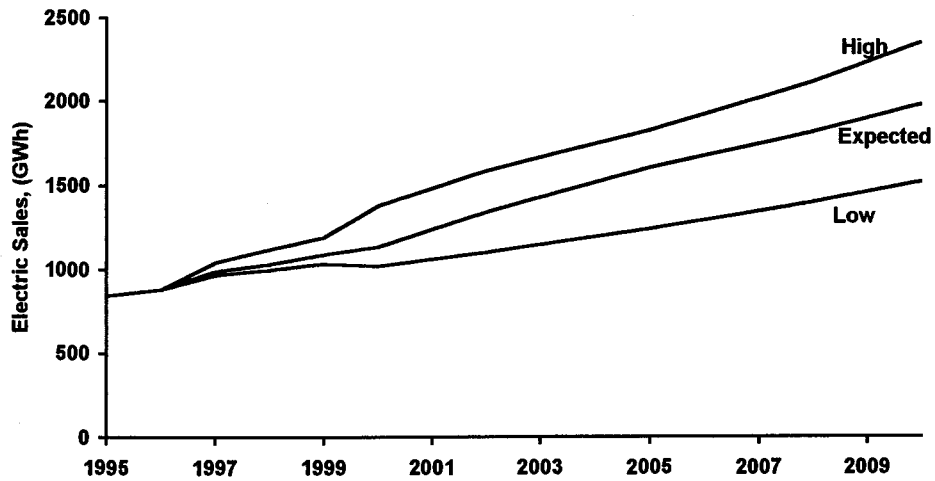
Interconnected Network Demand (GWh) - Expected Scenario

1995	1996	1997	1998	1999	2000	2001	2002
843.4	883.4	987.1	1029.4	1086.3	1133.5	1183.2	1341.5
2003	**2005**	**2006**	**2008**	**2009**	**2010**	**2011**	**2020**
6.01%	1598.2	4.14%	1805.2	4.41%	1968.0	4.41%	3030.0

The annual peak for these same years are presented below as MW.

1995	1996	1997	1998	1999	2000	2001	2002
167.5	180.5	184.5	190.1	198.2	204.4	213.4	241.9
2003	**2005**	**2006**	**2008**	**2009**	**2010**	**2011**	**2020**
6.01%	288.2	4.14%	325.56	4.41%	354.9	4.41%	546.4

Graphically the growth in energy demand is presented below:



The annual capacity factor for these same years is simply the annual energy usage divided by the peak production and 8760 hours.

1995	1996	1997	1998	1999	2000	2001	2002
57.5%	55.9%	61.1%	61.8%	62.6%	63.6%	63.3%	63.3%
2003	**2005**	**2006**	**2008**	**2009**	**2010**	**2015**	**2020**
63.1%	63.3%	63.3%	63.1%	63.2%	63.3%	63.9%	69.2%

1.2 T&D transmission efficiency

A Transmission and Distribution efficiency of 84.2 to 90.2% was utilized in a consistent fashion with the April 1997 draft Master Plan issued by SENELEC. When the sales figure is divided by this efficiency, the required net production is estimated. The utilized T&D efficiency is presented below.

Year	1996	1997	1998	1999	2000
T&D effic.	84.2%	87.2%	88.3%	89.4%	90.4%

2.0 PLANT DATA

The plant table on the following pages documents the major plant characteristics modeled within the ELFIN input. A few miscellaneous assumptions are documented below:

1. The GTI gas turbine has been assumed to start up as a simple cycle in 1999 and as a combined cycle in 2000, with a Take-or-Pay contract quantity of 182 GWh and 300 GWh respectively. The fuel price of the boot has been assumed as that of heavy oil, or $3.09/MBtu. This, along with the fixed and variable charges assumed in the model yield a composite cost in the vicinity of $0.06/kWh. In 2014, the plant is assumed to be dispatched based on it marginal cost as ownership is transferred to SENELEC.

2. The Manantali hydroelectric plant is assumed to provide power to SENELEC in 2003. The electric production delivered to SENELEC is assumed as 225 GWh distributed thorough out the year as determined by a SENELEC optimization routine with monthly percentages of 4, 4, 8, 9, 5, 5, 7, 7, 14, 12, 19, and 6%. The assumed peak capacity of the SENELEC portion of the plant is 90 MWe for August, September and October, and 60 MWe for the rest of the year. The run of the river flow requirement has been taken as 8.0 MW (SENELEC portion). This is based on the irrigation requirement of 200 m3/s out of an average flow of 639 m3/s. Manantali has been modeled with the pre-dispatch algorithm within the ELFIN program. The variable cost of electric production at Manantali has been taken as $0.024/kWh (1298 CFAF/kWh at 470 CFAF/$).

3. Unit specific average heat rates and load dependent cost of electric generation curves were utilized to develop reasonable load dependent heat rate inputs for the existing units.

4. Emission data is based on US EPA AP-42, unless otherwise noted.

PLANT DATA TABLE

Unit	Plant	Power House	Prime Mover	Unit Category	Rated Capacity MW	Net Capacity MW	Min. Cap MW	Fuel	Maintenance Rate (%)	Forced Outage Rate (%)	Year Installed	Probable Retirement	Age At Retirement
G101	Bel Air	C.II	ST	Min Con	12.8	10.2	4.1, 40%	HO	11.0	15.0	1953	2003	50
G102	Bel Air	C.II	ST	Min Con	12.8	10.2	4.1, 40%	HO	11.0	15.0	1955	2003	48
G103	Bel Air	C.II	ST	Min Con	12.8	10.2	4.1, 40%	HO	11.0	15.0	1959	2003	44
G104	Bel Air	C.II	ST	Min Con	12.8	10.2	4.1, 40%	HO	11.0	15.0	1961	2003	42
G105	Bel Air	C.I	Diesel	rapid start	4.5	4.25	1.1, 25%	97% HO/D	16.4	15.0	1991	2010	19
G106	Bel Air	C.I	Diesel	rapid start	4.5	4.25	1.1, 25%	97% HO/D	16.4	15.0	1991	2010	19
G301	C-d-B	C.III	ST	Min Con	27.5	25.8	10.3, 40%	HO	8.2	15.0	1966	2005	39
G302	C-d-B	C.III	ST	Min Con	30.0	28.1	11.2, 40%	HO	8.2	15.0	1975	2007	32
G303	C-d-B	C.III	ST	Min Con	30.0	28.1	11.2, 40%	HO	8.2	15.0	1978	2009	31
G401	C-d-B	C.IV	Diesel	rapid start	19.0	18.0	4.5, 25%	98% HO/D	16.4	15.0	1990	2013	23
G402	C-d-B	C.IV	Diesel	rapid start	19.0	18.0	4.5, 25%	98% HO/D	16.4	15.0	1990	2013	23
G403	C-d-B	C.IV	Diesel	rapid start	21.0	20.0	5.0, 25%	98% HO/D	16.4	15.0	1997	2020	23
TAG1	C-d-B	C.III	GT	rapid start	15.0	15.0	6.0, 40%	20%D/ NG	8.2	10.0	1971	2004	33
TAG2	C-d-B	C.III	GT	rapid start	20.0	20.0	8.0, 40%	20%D/ NG	8.2	10.0	1984	2014	30
TAG3	C-d-B	C.III	GT	rapid start	20.0	20.0	8.0, 40%	20%D/ NG	8.2	10.0	1995	NA	30
STL1-2	St. L.	-	Diesel	rapid start	3.25	2.5	0.6, 25%	50%D/HO	16.4	20.0	1979	2000	21
STL3-4	St. L.	-	Diesel	rapid start	2.0	1.8	0.6, 25%	50%D/HO	16.4	20.0	1980/87	1997	17
KAO1-4	Kaolack	-	Diesel	rapid start	3.5	3.2	0.8, 25%	97% HO/D	16.4	15.0	1982/88	2002/08	20
Boot	IPP	-	GTCC	rapid start	56.0	56.0	14, 25%	cond. dist (?)	7.75	5.0	1999	NA	NA
Hydr	Manantali	-	Hydro	pre-dispatch		90.0			0.0	0.0	2002	NA	NA
GT20	NEW	NEW	GT	rapid start		20.0	5, 25%	D or NG	7.75	5.0	tbd	NA	NA
GT60	NEW	NEW	GTCC	min const		60.0	15, 25%	D or NG	7.75	5.0	tbd	NA	NA
GT90	NEW	NEW	GTCC	min const		90.0	22.5, 25%	D or NG	7.75	5.0	tbd	NA	NA
Di05	NEW	NEW	Diesel	rapid start		5.0	2.0, 40%	D	16.0	5.0	tbd	NA	NA
Di20	NEW	NEW	Diesel	rapid start		20.0	8.0, 40%	97%HO/D	16.0	5.0	tbd	NA	NA
Di60	NEW	NEW	Diesel	rapid start		60.0	6.0, 10%	97%HO/D	16.0	5.0	tbd	NA	NA
Di90	NEW	NEW	Diesel	rapid start		90.0	6.0, 6.7%	97%HO/D	16.0	5.0	tbd	NA	NA
Cl90	NEW	NEW	Coal	min const.		90.0	22.5, 25%	Coal	12.0	4.0	tbd	NA	NA
Oil6	NEW	NEW	Oil	min const.		60.0	15.0, 25%	HO	10.0	3.0	tbd	NA	NA
Oil9	NEW	NEW	Oil	min const.		90.0	22.5, 25%	HO	10.0	3.0	tbd	NA	NA

Unit	Plant	Prime Mover	Net Capacity MW	Min. Cap MW	HR @ Min load	HR@ 50% Rated	HR@ 75% Rated	HR@ Max Modeled	Full Load Effic. (%, LHV)	Fixed O&M $/kW	Variable O&M mils/kWh
G101	Bel Air	ST	10.2	4.1, 40%	20,000	18,700	16,750	17,100	19.9	64	0.74
G102	Bel Air	ST	10.2	4.1, 40%	20,000	18,700	16,750	17,100	19.9	64	0.74
G103	Bel Air	ST	10.2	4.1, 40%	20,000	18,700	16,750	17,100	19.9	64	0.74
G104	Bel Air	ST	10.2	4.1, 40%	20,000	18,700	16,750	17,100	19.9	64	0.74
G105	Bel Air	Diesel	4.25	1.1, 25%	9,680			9,060	37.7	76	4.8
G106	Bel Air	Diesel	4.25	1.1, 25%	9,680			9,060	37.7	76	4.8
G301	C-d-B	ST	25.8	10.3, 40%	13,650	13,330	12,360	12,320	27.7	39	0.56
G302	C-d-B	ST	28.1	11.2, 40%	13,650	13,330	12,360	12,320	27.7	36	0.56
G303	C-d-B	ST	28.1	11.2, 40%	13,650	13,330	12,360	12,320	27.7	36	0.56
G401	C-d-B	Diesel	18.0	4.5, 25%	13,470	9,930	8,860	8,860	38.5	82	4.0
G402	C-d-B	Diesel	18.0	4.5, 25%	13,470	9,930	8,860	8,860	38.5	82	4.0
G403	C-d-B	Diesel	20.0	5.0, 25%	13,470	9,930	8,860	8,860	38.5	74	4.0
TAG1	C-d-B	GT	15.0	6.0, 40%	30,000	26,750	21,400	19,700	17.3	20	0.001
TAG2	C-d-B	GT	20.0	8.0, 40%	30,000	26,750	21,400	19,700	17.3	20	0.001
TAG3	C-d-B	GT	20.0	8.0, 40%	25,000	21,200	19,700	17,600	19.4	20	0.001
STL1-2	St. L.	Diesel	2.5	0.6, 25%	10,100			10,100	33.8	85	7.9
STL3-4	St. L.	Diesel	1.8	0.6, 25%	10,100			10,100	33.8	85	7.9
KAO1-4	Kaolack	Diesel	3.2	0.8, 25%	9,450			9,450	36.1	101	4.5
Boot	IPP	GTCC	56.0	14, 35%	9,910	8,840	7,710	7,400	46.1	187/52.8	6.5
Hydr	Manantali	Hydro	90.0								24.0
GT20	NEW	GTCC	20.0	5, 25%	17,250	13,600	11,750	10,800	31.6	50.0	7.0
GT60	NEW	GTCC	60.0	15, 25%	10,650	8,380	7,460	7,100	48.1	40.0	6.0
GT90	NEW	GTCC	90.0	22.5, 25%	10,580	8,320	7,400	7,050	48.4	37.0	6.0
Di05	NEW	Diesel	5.0	2.0, 40%	9,680			8,800	38.8	60.0	7.5
Di20	NEW	Diesel	20.0	8.0, 40%	8,800			8,000	42.7	55.0	7.5
Di60	NEW	Diesel	60.0	6.0, 10%	7,940			7,940	43.0	50.0	7.5
Di90	NEW	Diesel	90.0	6.0, 6.7%	7,940			7,940	43.0	45.0	7.5
Cl90	NEW	Coal	90.0	22.5, 25%	12,450	10,260	9,690	9,500	35.9	40.0	2.5
oil6	NEW	Oil	60.0	15.0, 25%	12,860	10,610	10,020	9,820	34.8	34.0	2.0
oil9	NEW	Oil	90.0	22.5, 25%	12,100	9,980	9,425	9,240	36.9	31.0	2.0

Note: New plant heat rates are degraded by 3% within the ELFIN model.
The boot FO&M of 187 assumed for the first 15 years of operation, subsequently 52.8 is assumed.

Unit	Plant	Prime Mover	Net Capacity MW	SO2 lb/MMBtu	NOX lb/MMBtu	CO lb/MMBtu	Part lb/MMBtu
G101	Bel Air	ST	10.2	1.2	0.37	0.033	0.10
G102	Bel Air	ST	10.2	1.2	0.37	0.033	0.10
G103	Bel Air	ST	10.2	1.2	0.37	0.033	0.10
G104	Bel Air	ST	10.2	1.2	0.37	0.033	0.10
G105	Bel Air	Diesel	4.7	1.2	1.9	0.85	0.10
G106	Bel Air	Diesel	4.7	1.2	1.9	0.85	0.10
G301	C-d-B	ST	25.3	1.2	0.28	0.033	0.10
G302	C-d-B	ST	27.6	1.2	0.28	0.033	0.10
G303	C-d-B	ST	27.6	1.2	0.28	0.033	0.10
G401	C-d-B	Diesel	18.7	1.2	1.9	0.85	0.10
G402	C-d-B	Diesel	18.7	1.2	1.9	0.85	0.10
G403	C-d-B	Diesel	21.5	1.2	1.9	0.85	0.10
TAG1	C-d-B	GT	15.0	0.04	0.7	0.48	0.04
TAG2	C-d-B	GT	20.0	0.2	0.7	0.48	0.04
TAG3	C-d-B	GT	20.0	0.2	0.7	0.48	0.04
STL1-2	St. L.	Diesel	2.9	0.2	1.9	0.85	0.10
STL3-4	St. L.	Diesel	1.8	0.2	1.9	0.85	0.10
KAO1-4	Kaolack	Diesel	3.3	1.2	1.9	0.85	0.10
Boot	IPP	GTCC	56.0	-	0.7	0.48	0.04
Hydr	Manantali	Hydro	90.0	0.0	0.0	0.0	0.0
GT20	NEW	GTCC	20.0	0.0/1.2	0.4/0.7	0.11/0.05	0.02/0.04
GT60	NEW	GTCC	60.0	0.0/1.2	0.4/0.7	0.11/0.05	0.02/0.04
GT90	NEW	GTCC	90.0	0.0/1.2	0.4/0.7	0.11/0.05	0.02/0.04
Di05 [a]	NEW	Diesel	5.0	1.2	1.9	0.85	0.1
Di20 [a]	NEW	Diesel	20.0	1.2	1.9	0.85	0.1
Di60 [a]	NEW	Diesel	60.0	1.2	1.9	0.85	0.1
Di90 [a]	NEW	Diesel	90.0	1.2	1.9	0.85	0.1
Cl90	NEW	Coal	90.0	1.5	1.0	0.02	0.02
oil6	NEW	Oil	60.0	1.2	0.37	0.033	0.1
oil9	NEW	Oil	90.0	1.2	0.37	0.033	0.1

Notes: a. Emissions data is based upon EPA document AP-42.

Unit	Prime Mover	Fuel	Preconstruction time (yr)	Construcit on time (yr)	First Possible Year	Max No. Of units	Max No[d] of units/yr	Investment Cost $/kW	Fixed O&M $/kW	Variable O&M mils/kWh	Plant Life (yr)
GS60	GTCC	NG	1	2	2001	3[a]	1	950	40	6.0	20
GS90	GTCC	NG	1	2	2001[b]	2[a]	1	840	37	6.0	20
GT20	GT	D	1	1	2000	10[d]	1	875	50	7.0	20
GT60	GTCC	D	1	2	2001	6[d]	1	950	40	6.0	20
GT90	GTCC	D	1	2	2001[b]	4[d]	1	840	37	6.0	20
Di05	Diesel	D	1	1	2000	10[d]	4	2150	60	7.5	20
Di20	Diesel	HO	1.5	1.5	2001	10[d]	2	1425	55	7.5	20
Di60	Diesel	HO	1.5	1.5	2001	6[d]	1	1040	50	7.5	20
Di90	Diesel	HO	1.5	1.5	2001	4[d]	1	1000	50	7.5	20
Cl90	Coal	Coal	3	3	2004	4[d]	1	1900/1600[c]	40	2.5	20
oil6	Oil	HO	2.5	2.5	2003	6[d]	1	1630	34	2.0	20
oil9	Oil	HO	2.5	2.5	2003	4[d]	1	1450	31	2.0	20

a. GS60 and GS90 have an aggregate maximum of 3 units to reflect the limited gas reserve.
b. The first year allowed by the stability analysis may be later.
c. $1900/Kw for the first unit, 1600 for the second.
d. Currently disabled in model. That is maximum number of units to year are set to a large number.

3.0 FUEL PRICING

The following fuel prices in 1997 currency, are utilized in the generation planning model.

	Heavy Oil	Diesel	Gas	Coal
Dakar	$3.09/MBtu $119.09/tonne 64,308 FCFA/t	$6.03/MBtu $245.13/tonne 132,372 FCFA/t	$4.81/MBtu* $185.19/kNm^3 100,000 FCFA/t	$2.27/MBtu $60/tonne 32,400 FCFA/t
St. Louis	$4.07/MBtu	$6.95/MBtu	NA	NA
Kahone	$3.75/MBtu	$6.65/MBtu	NA	NA
LHV kcal/kg	9,700 kcal/kg	10,250 kcal/kg	9709 kcal/Nm^3	6,667 kcal/kg

* The gas price of $2.70/MBtu was used for the increased reserves case and is based upon the World Bank Price for Natural Gas in Europe.
The above fuel costs are based on an exchange rate of 540 FCFA/$.

A composite fuel cost is used in plants where dual fuels are utilized.

	Fuel Cost
Dakar 97% HO / 3%D 98% HO / 2%D 20% DO / 80%NG (hi) 20% DO / 80%NG (lo)	 $3.18/MBtu $3.15/MBtu $5.05/MBtu $3.37/MBtu
St Louis 50% HO / 50%D	 $5.20/MBtu
Kahone 97% HO / 3%D	 $3.84/MBtu

An additional Transportation costs have been assumed for fuel destined for St. Louis and Kahone of approximately $37.39/tonne (~20,200 FCFA/tonne) and $25.29/tonne (~13,660 FCFA/tonne) respectively. On a heat input basis, this amounts to roughly $0.95/MBtu and $0.64/MBtu respectively.

World Bank Based Fuel Escalation

Year	1998	1999	2000	2001
Raw crude	-5.0%	1.0%	1.0%	0.0%
Coal	0.4%	0.1%	0.1%	0.0%

No fuel escalation was assumed in the generation plan.

4.0 ECONOMIC AND GENERAL MODELING INPUTS

4.1 Economic Data

1. The model results are presented in 1998 constant dollar basis.
2. An inflation rate of 4%.
3. A nominal discount rate of 14% for a real discount rate of 10%.
4. General escalation of 0.0%. Extension period escalation of 0.0%. Fuel escalation per above.

4.2 General Modeling Assumptions/Data

The majority of inputs used in the ELFIN input model were taken from existing feasibility studies, load forecast and generation planning documents. The available information included typical load shapes, annual energy consumption and peak demand projections, and plant specific information including such as capacity, average heat rate, forced and planned outage rates, primary fuel, and minimum capacities.

Other ELFIN inputs were assumed, yet are based on reasonable power engineering practices. These major assumptions are documented below:

1. The commitment and spinning reserve target levels have been set as 105% of the peak demand to reflect the small quantity of spinning reserve that results from the SENELEC system operation without a managed spinning reserve target. For a 200 MW peak demand, this is equivalent to 10 MW of spinning reserve.
2. As a sensitivity, the "managed" commitment and spinning reserve target levels have been set as a percentage to cover the loss of the largest unit. For example, the largest unit in 1997 is 30 MW which is 16% of the 185 MW peak demand.

	1997	1998	1999	2000	2001	2002	2003
Spinning Reserve	16%	16%	26%	27%	27%	25%	**23%**
	2004	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
Spinning Reserve	22%	21%	20%	19%	18%	17%	**17%**

3. Cost of Energy-Not-Served (ENS) (or the Cost-of-Lapsing): 1106 CFAF/kWh ($2.05/kWh). This cost has been taken from the April 1997 Master plan.

The cost to the national economy of ENS is an important factor in determining the ultimate cost of an expansion plan. Studies have been made for various countries to determine an appropriate cost for this factor. One such study made for the Electricity Generating Authority of Thailand[2,3] would suggest that the price of the ENS should be in the range of CFAF2000/kWh rather than the assumed CFAF1106/kWh. Therefore a sensitivity to the Cost of ENS will be performed at double the nominal cost.

4. Reliability levels were allowed to float in the evaluation of options. ELFIN was allowed to minimize the total production cost, of which unserved energy is a part. Resulting reliability levels were checked for reasonableness.

5. ELFIN has been run with 5 seasonal periods being developed from the monthly data. The peak month, October, is modeled along with 4 "quarters." The last period is two months.

6. The timing of plant maintenance has been allowed to float such that ELFIN will levelize the reserve margin while meeting the annual maintenance rate input.

7. Heat rates for the proposed units were developed from vendor information, heat balances, and engineering judgment.

8. The BOOT capacity (56 MW) and performance values have been assumed from a range of available information. The assumed capacity and performance have been modeled to reflect a seasonal variation. That is the capacity has been estimated as 52 MW in the hot season and 56 MW in the cooler seaon.

9. The BOOT was modeled as a take or pay unit at $0.06/kWh in 1995 dollars, until it is turned over in the year 2014. At this point, the BOOT costs are based on it's assumed heat rate and fuel price.

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[1] "Forecasting Long Term Demand for Electricity in Senegal (1996 - 2010)," SENELEC Department of Innovation Planning and Equipment, Division of Background Economic Surveys.

[2] Sanghvi, Aron P. Optional Electricity Supply Reliability Using Customer Shortage Costs Criterion Inc. The Value of Service Reliability to Consumers, EPRI EA-4494, Electric Power Research Institute, Palo Alto, CA, USA, 1986.

[3] Sherman, Frank J., et al. The Cost of an Outage Utility Management & Corporate Planning Volume 1, Proceedings of the Sixth Conference on Electric Supply Industry, Jakarta, Indonesia, 1986.

Appendix C: Heat Balances

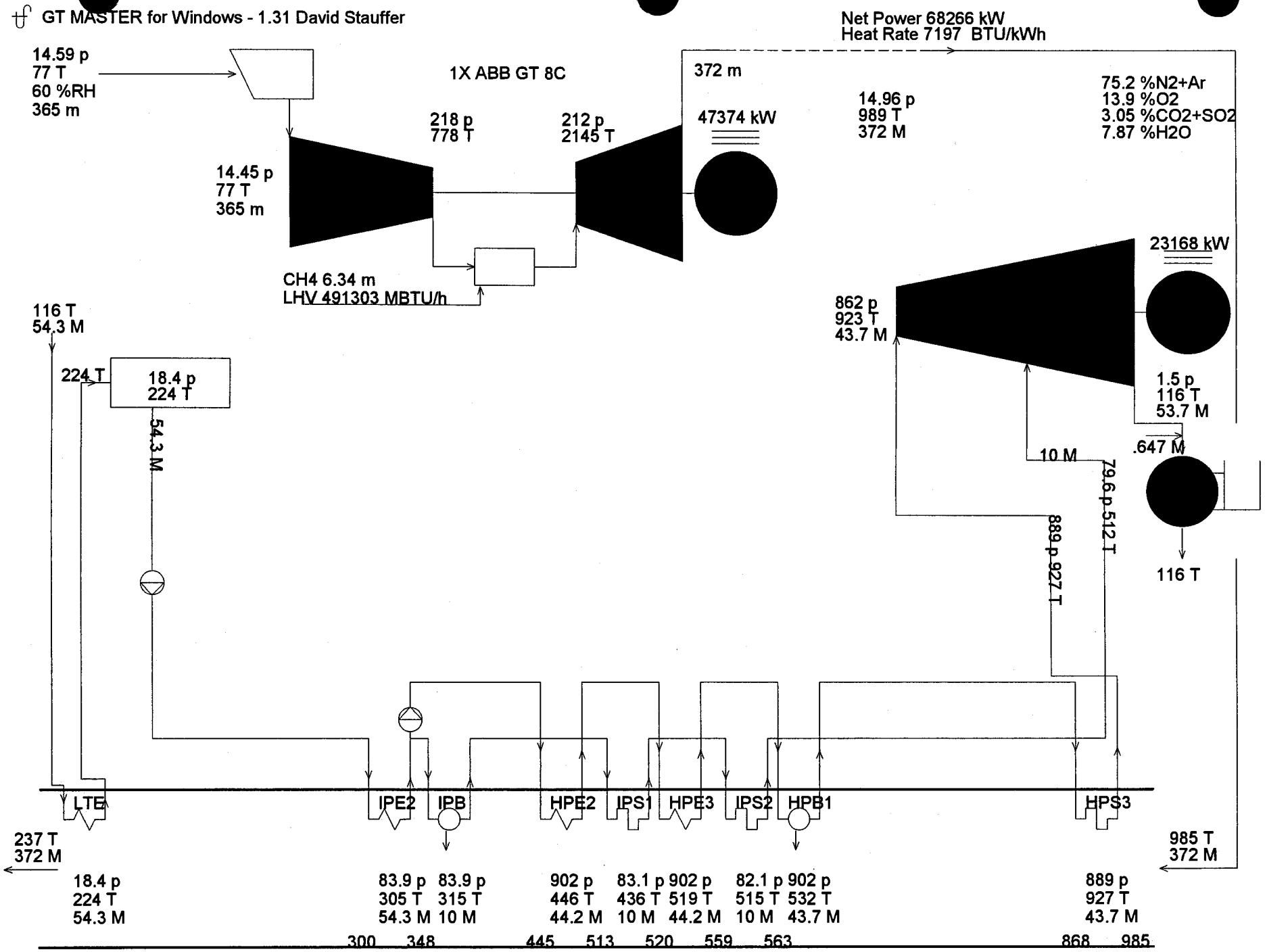
Numerous heat balances were developed by Parsons in support of the Section 4 option screening effort. The preliminary ABB GT8C combined cycle heat balance developed for this screening effort is presented as being representative of the numerous balances developed for screening. (Note: These preliminary balances are different in several important respects from the final balances. Most notable is the effect of siting on the cooling water source: cooling towers versus direct cooling. In addition, temperatures, humidities, and elevations, and other parameters were all refined for the final balances.)

Of course, this appendix presents the final heat balances which were refined in support of the conceptual design effort. The heat balances and conceptual design information is also presented here for the:

1. ABB GT8C land based cycle (in support of Section 8), and
2. Seimens Westinghouse 251B11 Barge-mounted plant cycle (in support of Section 10).

Appendix C:
Preliminary Heat Balance
for the ABB GT8C Gas Turbine
as Utilized in the Section 4 Screening Effort

GT MASTER for Windows - 1.31 David Stauffer



p[psia], T[F], m[lb/s]

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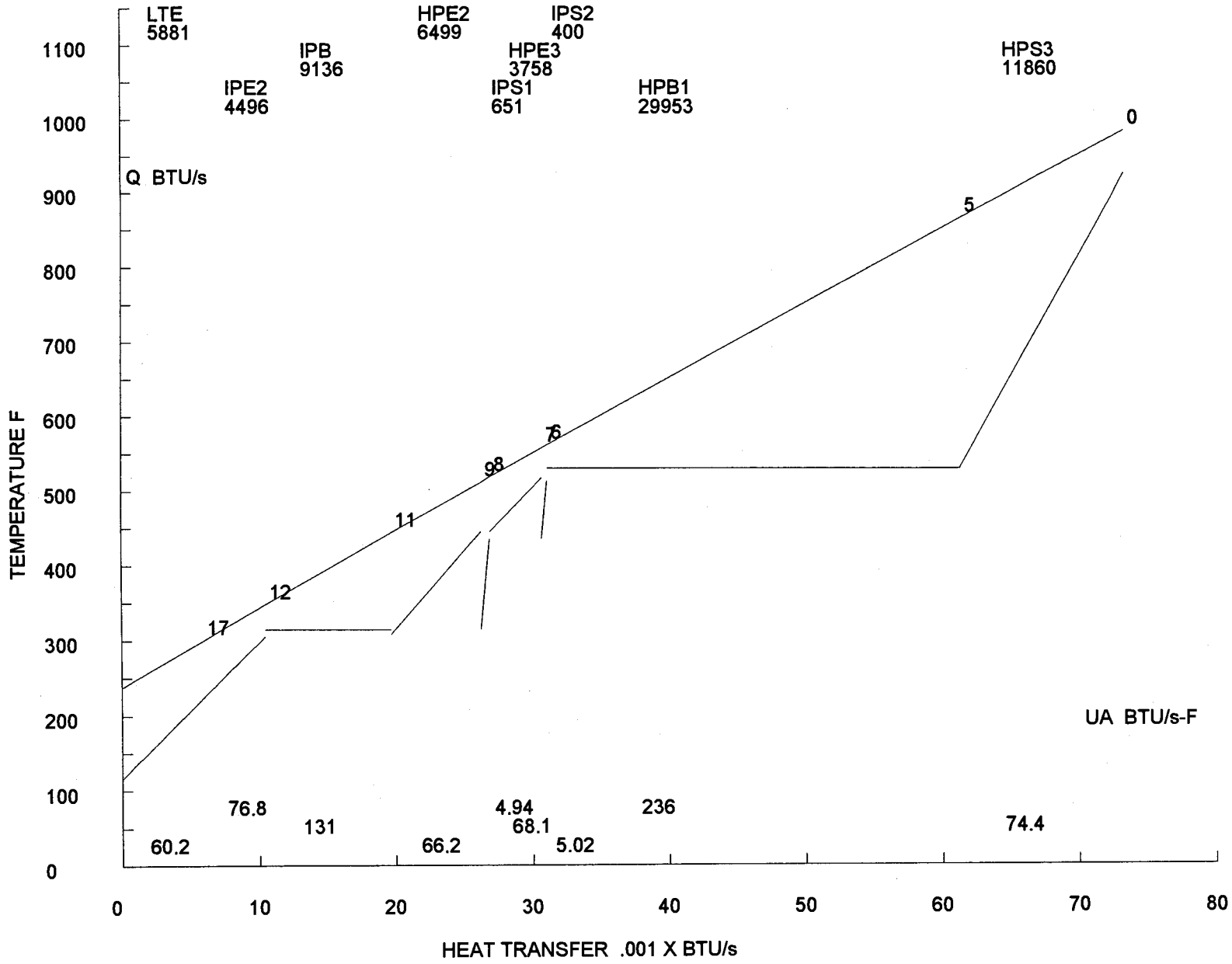
GT MASTER for Windows - 1.31 David Stauffer

Net Power 68266 kW
Heat Rate 7197 BTU/kWh



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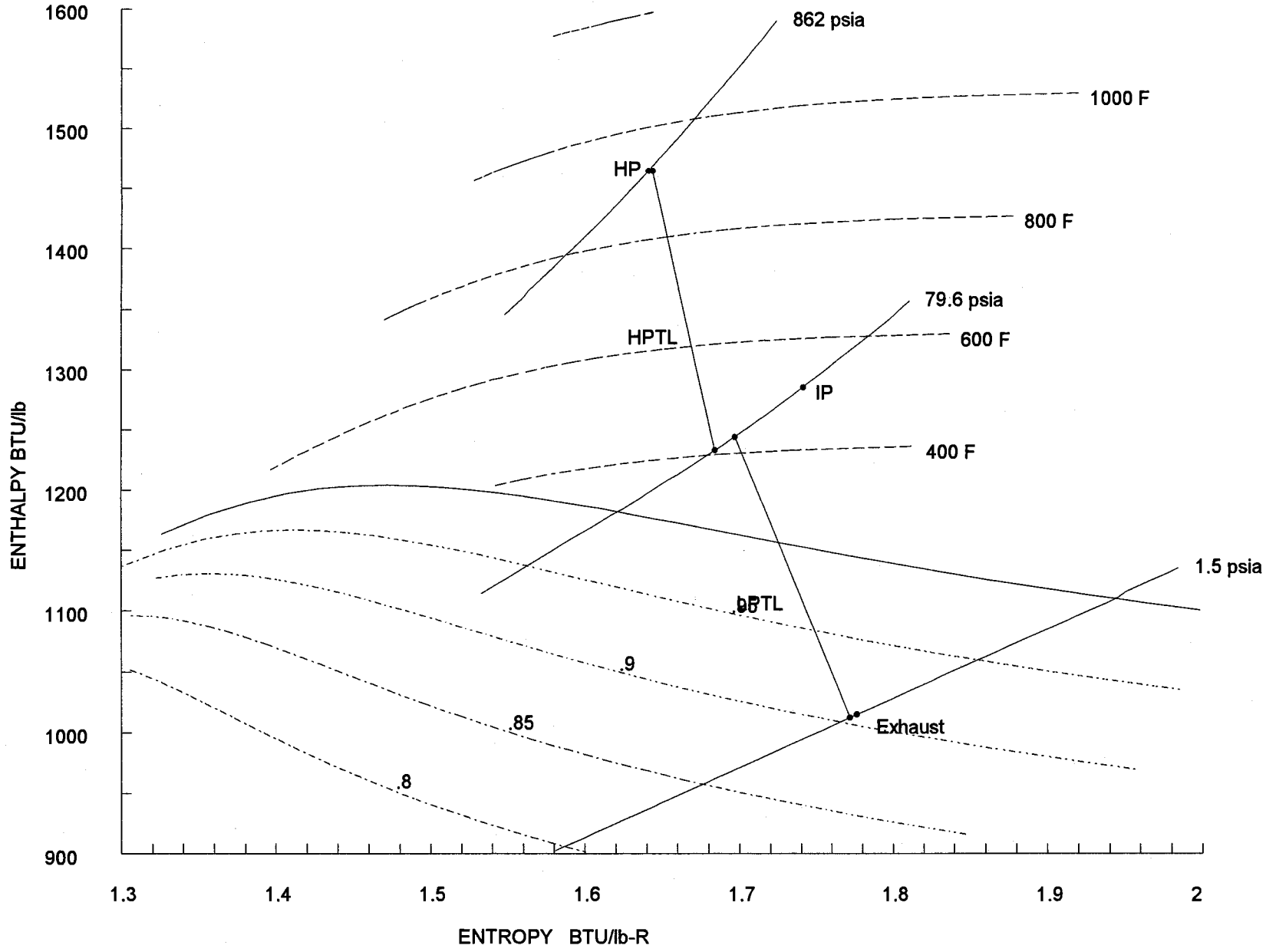
GT MASTER for Windows - 1.31 David Stauffer

Net Power 68266 kW
Heat Rate 7197 BTU/kWh



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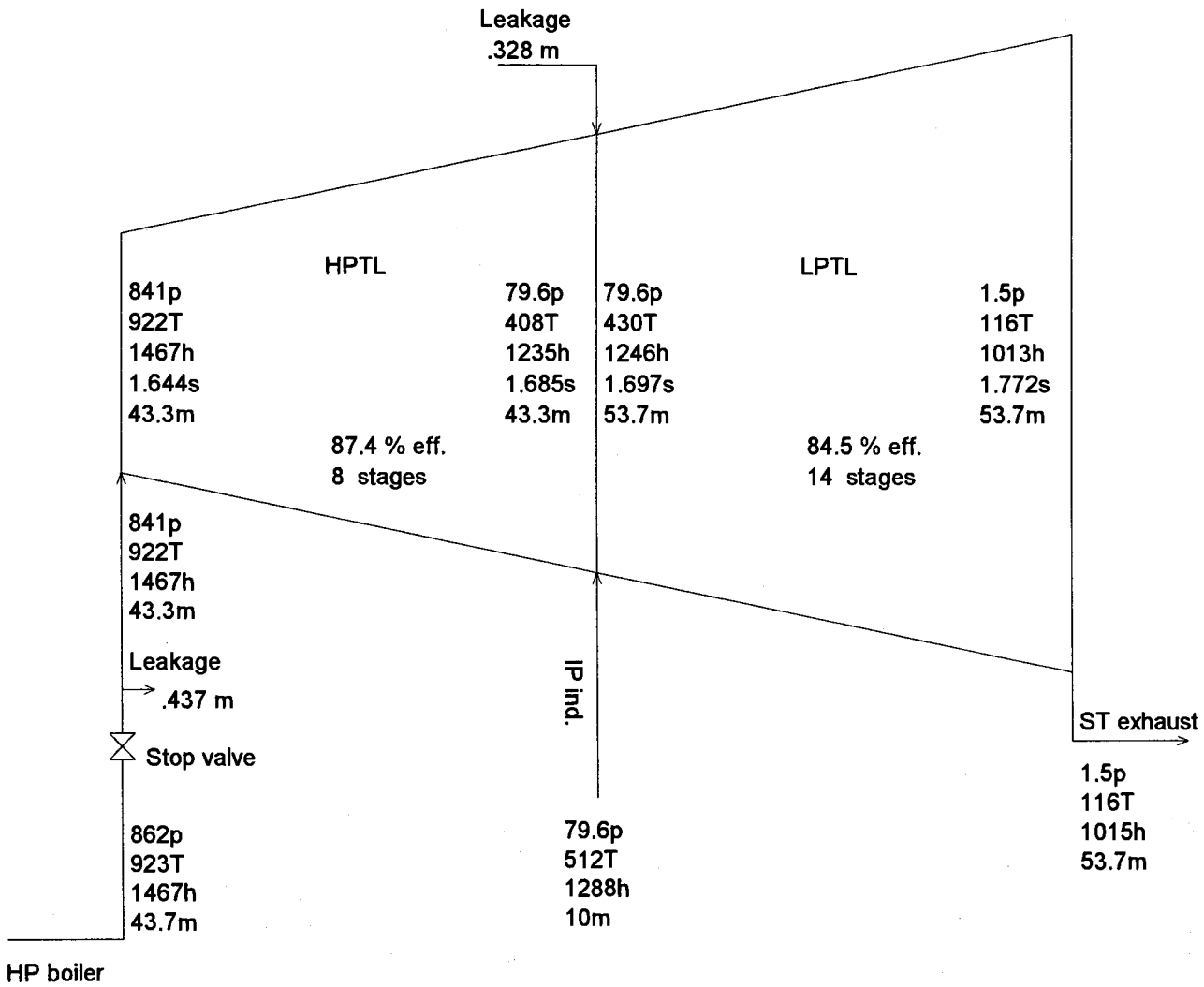
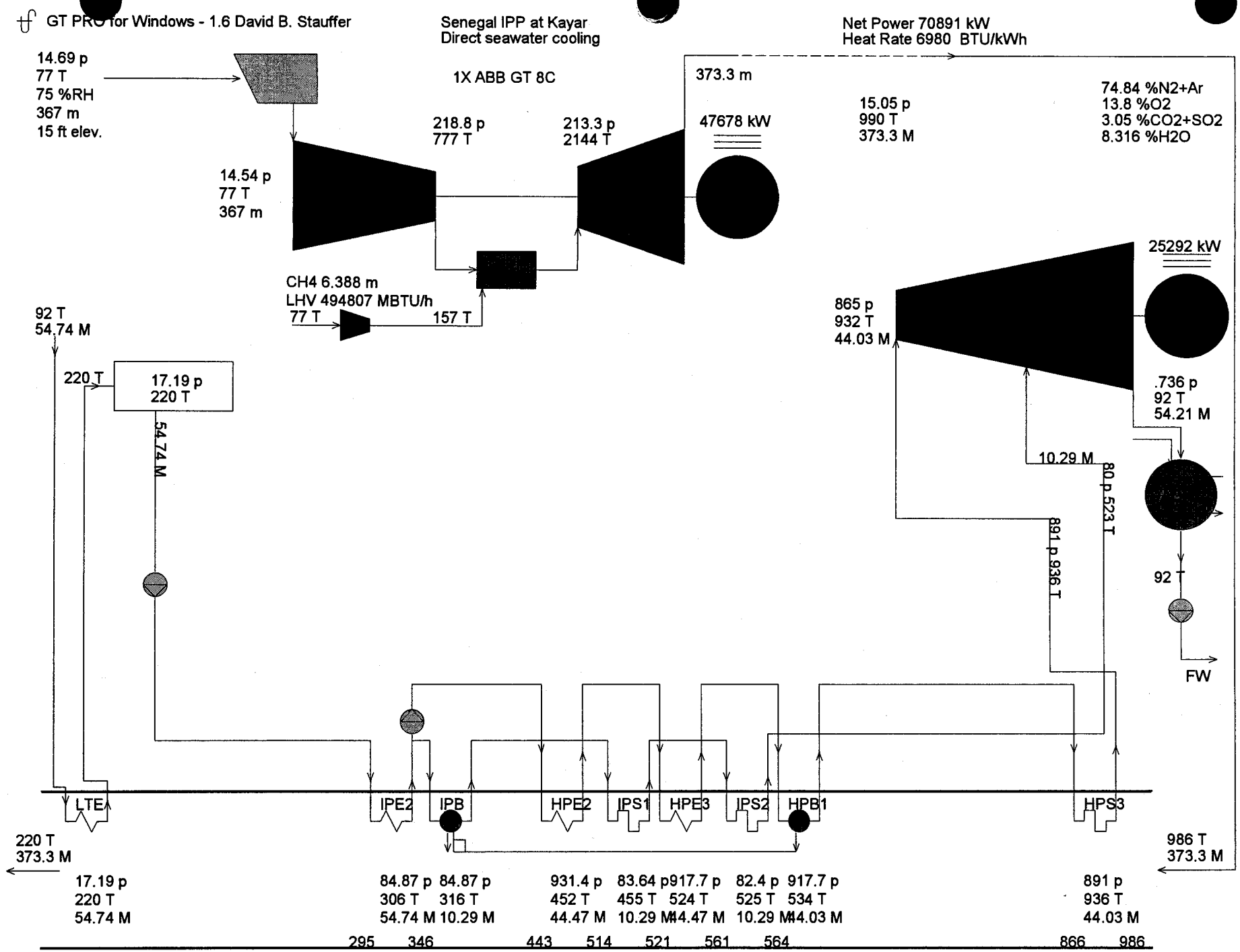


p[psia], T[F], h[BTU/lb], s[BTU/lb-R], m[lb/s]

725[illegible]30-1998 17:46:21 file=R:\SENEGAL\WORK\DBS\S-ABGT8C.GTM

Appendix C:
Heat Balance
for the ABB GT8C Land Based GTCC
in Support of the Section 8 Conceptual Design


GT PRO for Windows - 1.6 David B. Stauffer
Senegal IPP at Kayar
Direct seawater cooling
Net Power 70891 kW
Heat Rate 6980 BTU/kWh
14.69 p
77 T
75 %RH
367 m
15 ft elev.
1X ABB GT 8C
373.3 m
47678 kW
218.8 p
777 T
213.3 p
2144 T
14.54 p
77 T
367 m
15.05 p
990 T
373.3 M
74.84 %N2+Ar
13.8 %O2
3.05 %CO2+SO2
8.316 %H2O
CH4 6.388 m
LHV 494807 MBTU/h
77 T
157 T
25292 kW
865 p
932 T
44.03 M
92 T
54.74 M
220 T
17.19 p
220 T
54.74 M
.736 p
92 T
54.21 M
10.29 M
80 p 523 T
891 p 936 T
92 T
FW
LTE
IPE2
IPB
HPE2
IPS1
HPE3
IPS2
HPB1
HPS3
220 T
373.3 M
986 T
373.3 M
17.19 p
220 T
54.74 M
84.87 p
306 T
54.74 M
84.87 p
316 T
10.29 M
931.4 p
452 T
44.47 M
83.64 p
455 T
10.29 M
917.7 p
524 T
44.47 M
82.4 p
525 T
10.29 M
917.7 p
534 T
44.03 M
891 p
936 T
44.03 M
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521
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564
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986
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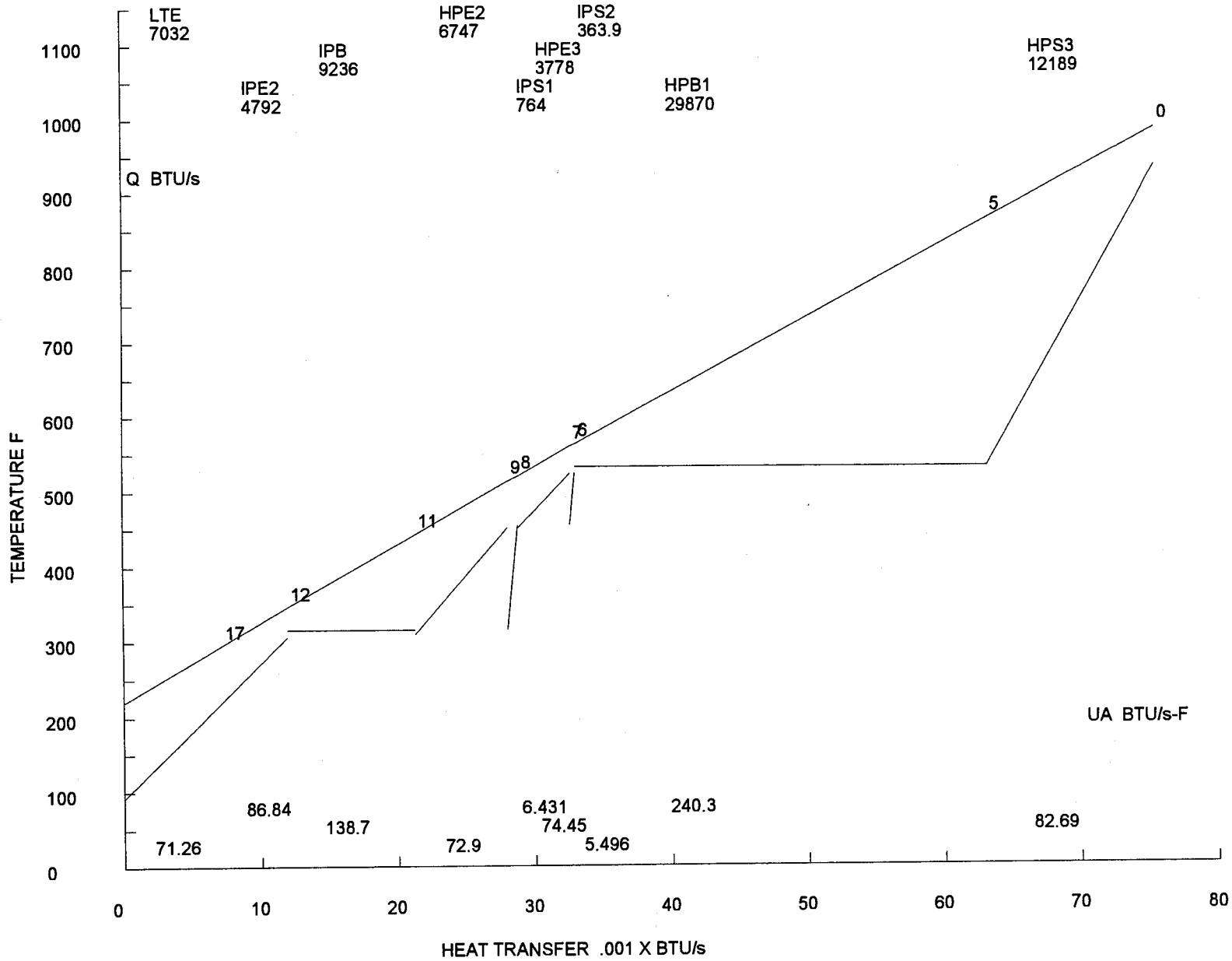
Senegal IPP at Kayar
Direct seawater cooling

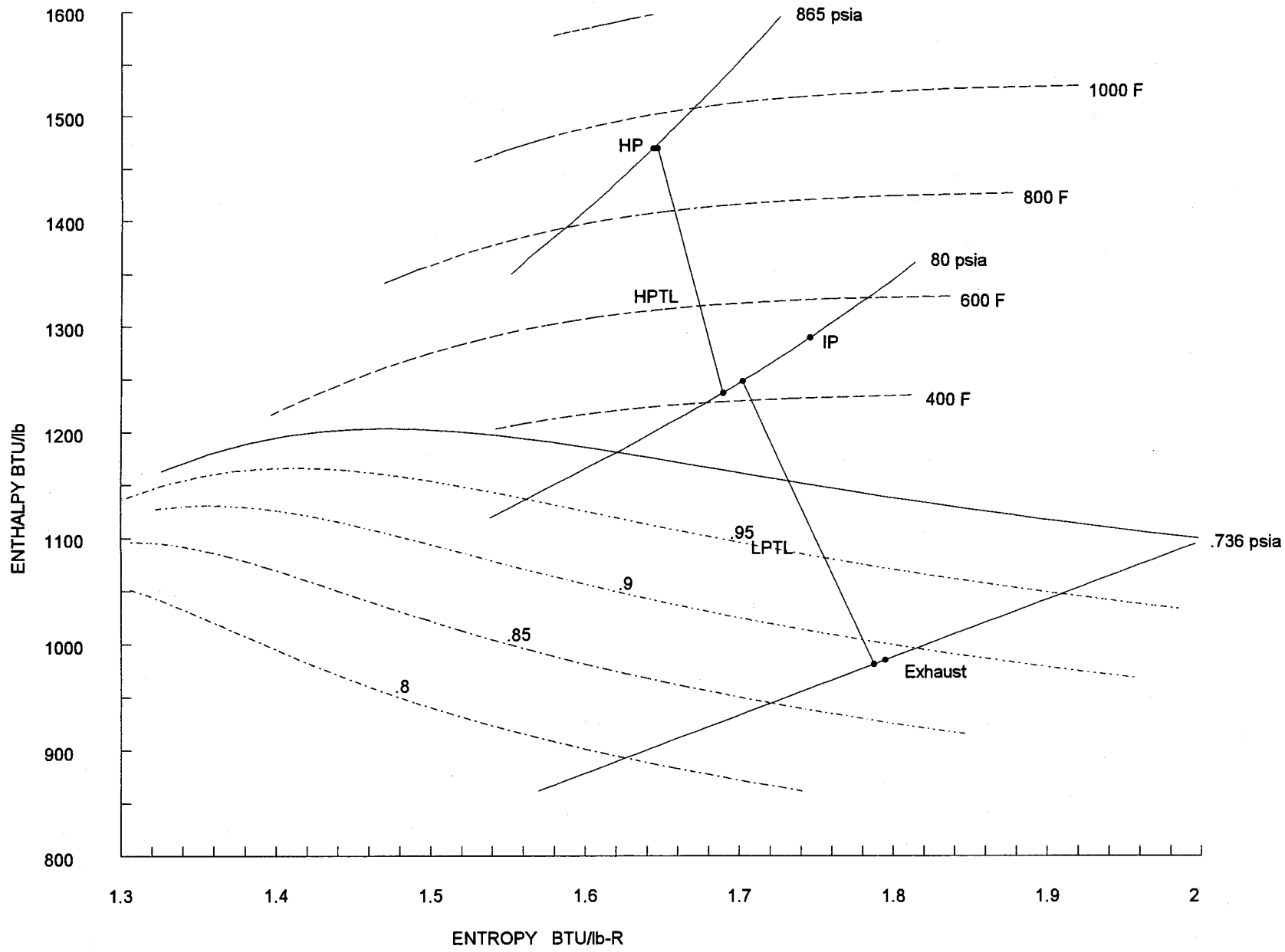
Net Power 70891 kW
Heat Rate 6980 BTU/kWh



GT PRO for Windows - 1.6 David B. Stauffer

Senegal IPP at Kayar
Direct seawater cooling

Net Power 70891 kW
Heat Rate 6980 BTU/kWh



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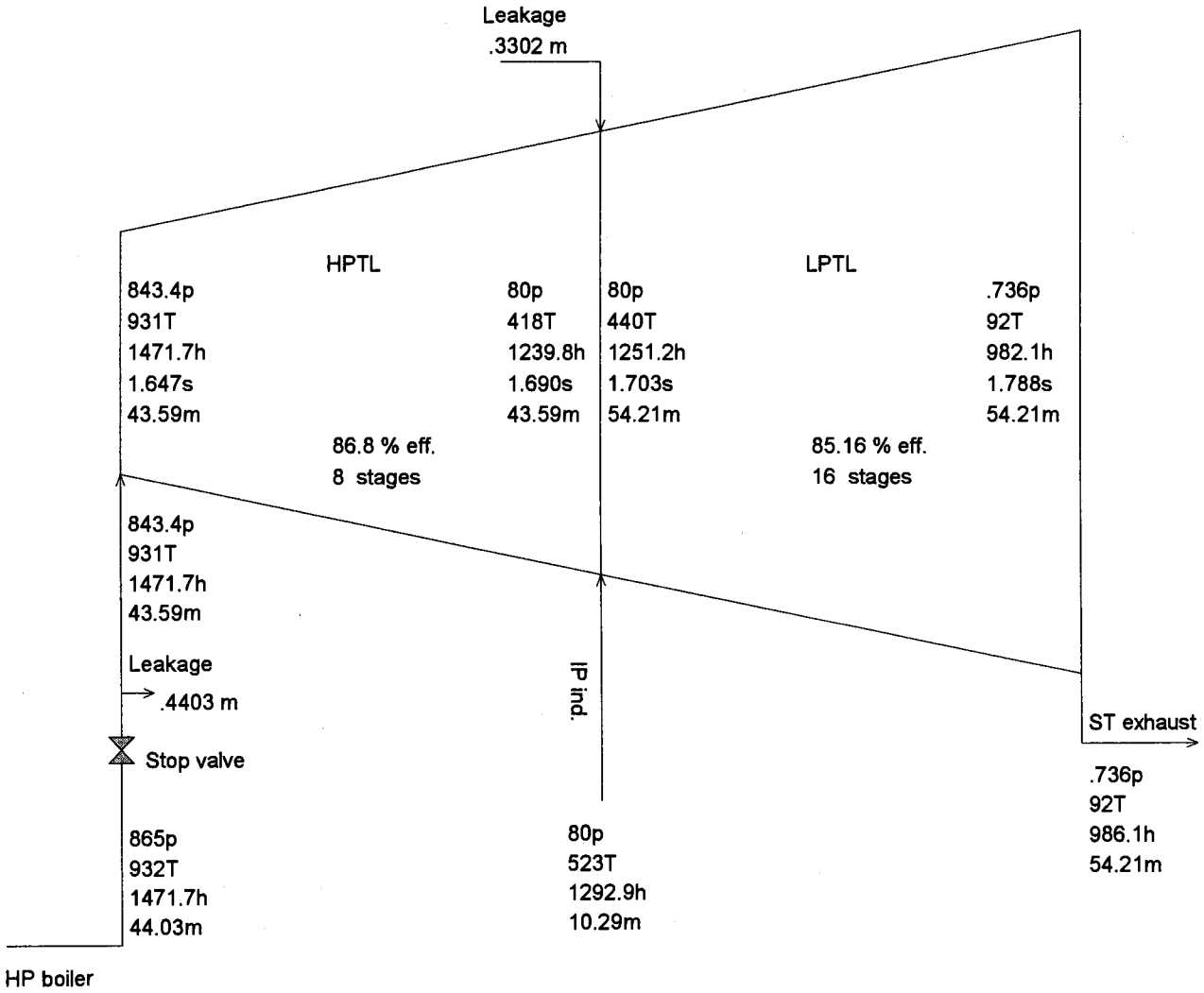
GT PRO for Windows - 1.6 David B. Stauffer

Senegal IPP at Kayar
Direct seawater cooling

ST Gross Power 25828 kW



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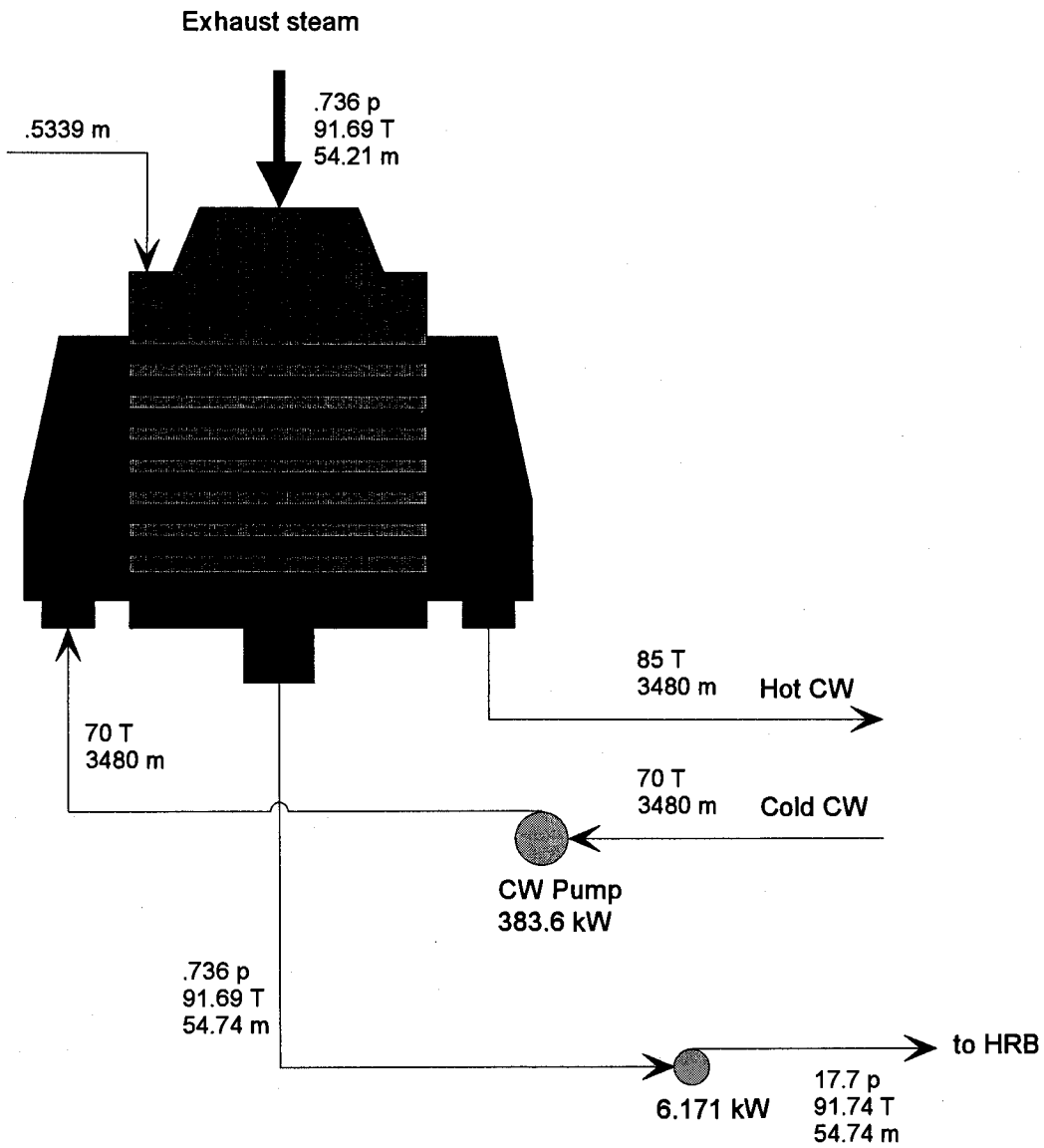
GT PRO for Windows - 1.6 David B. Stauffer

Senegal IPP at Kayar
Direct seawater cooling



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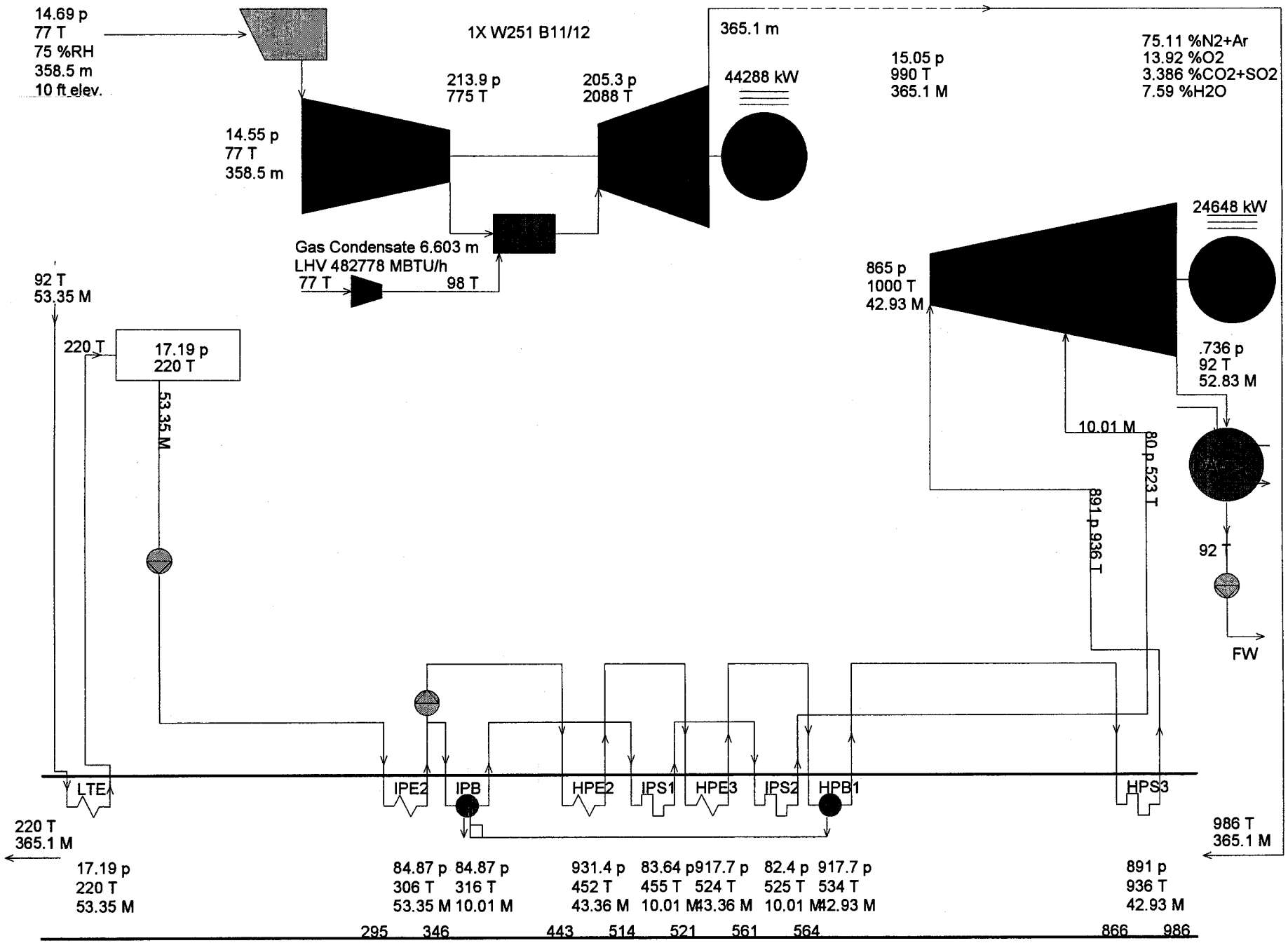
Appendix C:
Heat Balance
for the Seimens Westinghouse 251B11 Barge Mounted GTCC
in Support of the Section 10 Conceptual Design

GT PRO for Windows - 1.6 David B. Stauffer

Senegal Barge IPP at Bel Air
Direct seawater cooling

Net Power 67284 kW
Heat Rate 7175 BTU/kWh



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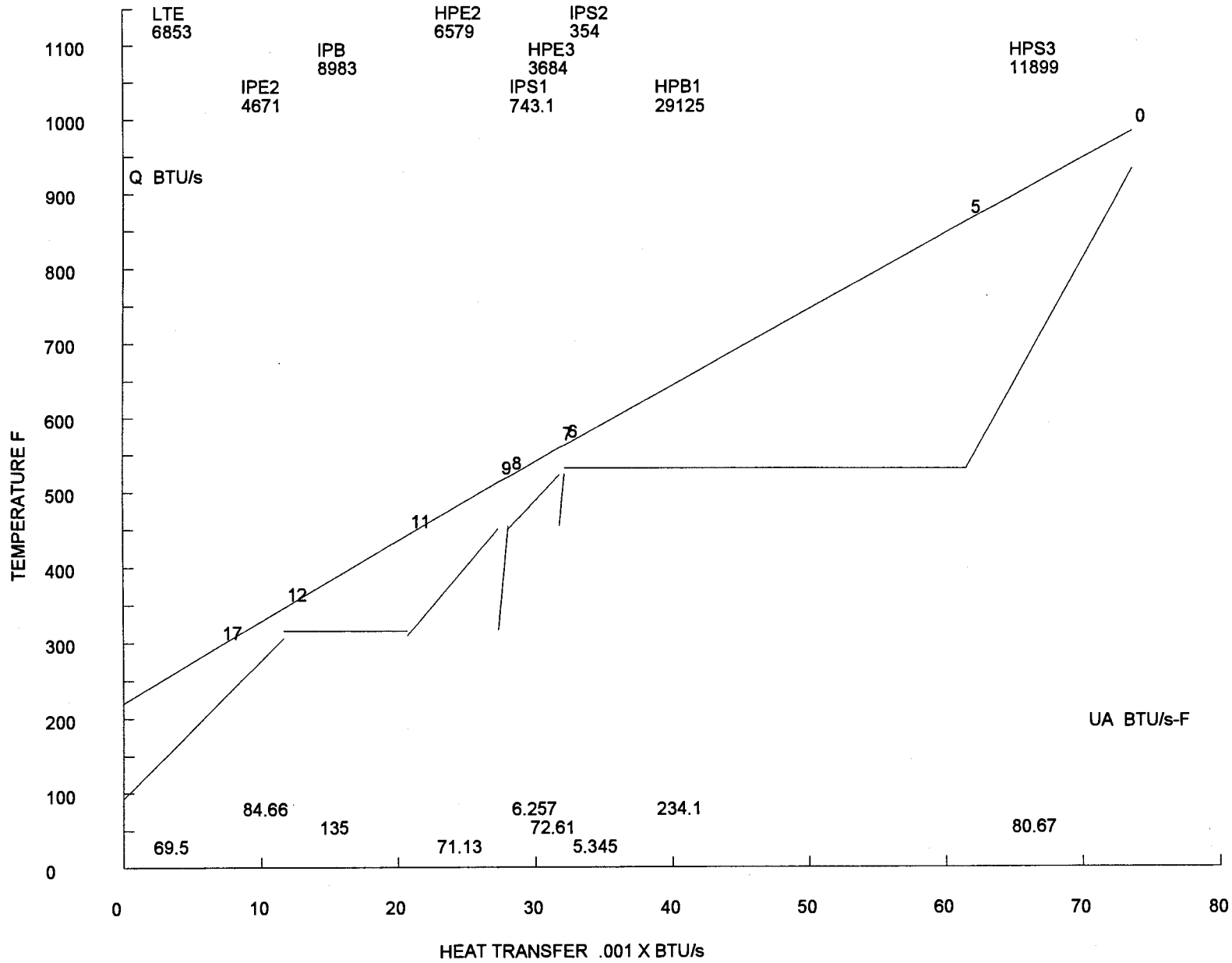
GT PRO for Windows - 1.6 David B. Stauffer

Senegal Barge IPP at Bel Air
Direct seawater cooling

Net Power 67284 kW
Heat Rate 7175 BTU/kWh



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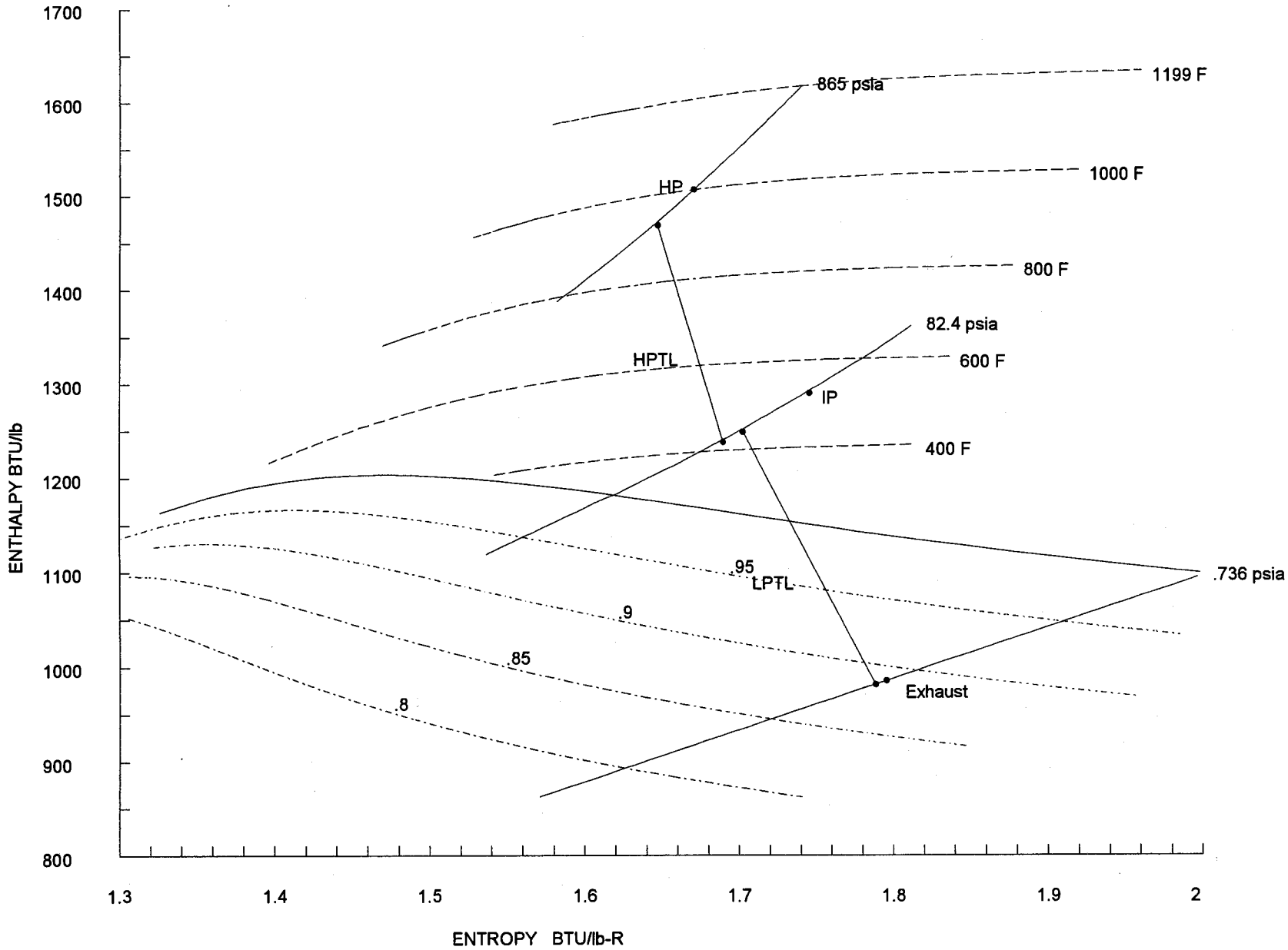
GT PRO for Windows - 1.6 David B. Stauffer

Senegal Barge IPP at Bel Air
Direct seawater cooling

Net Power 67284 kW
Heat Rate 7175 BTU/kWh



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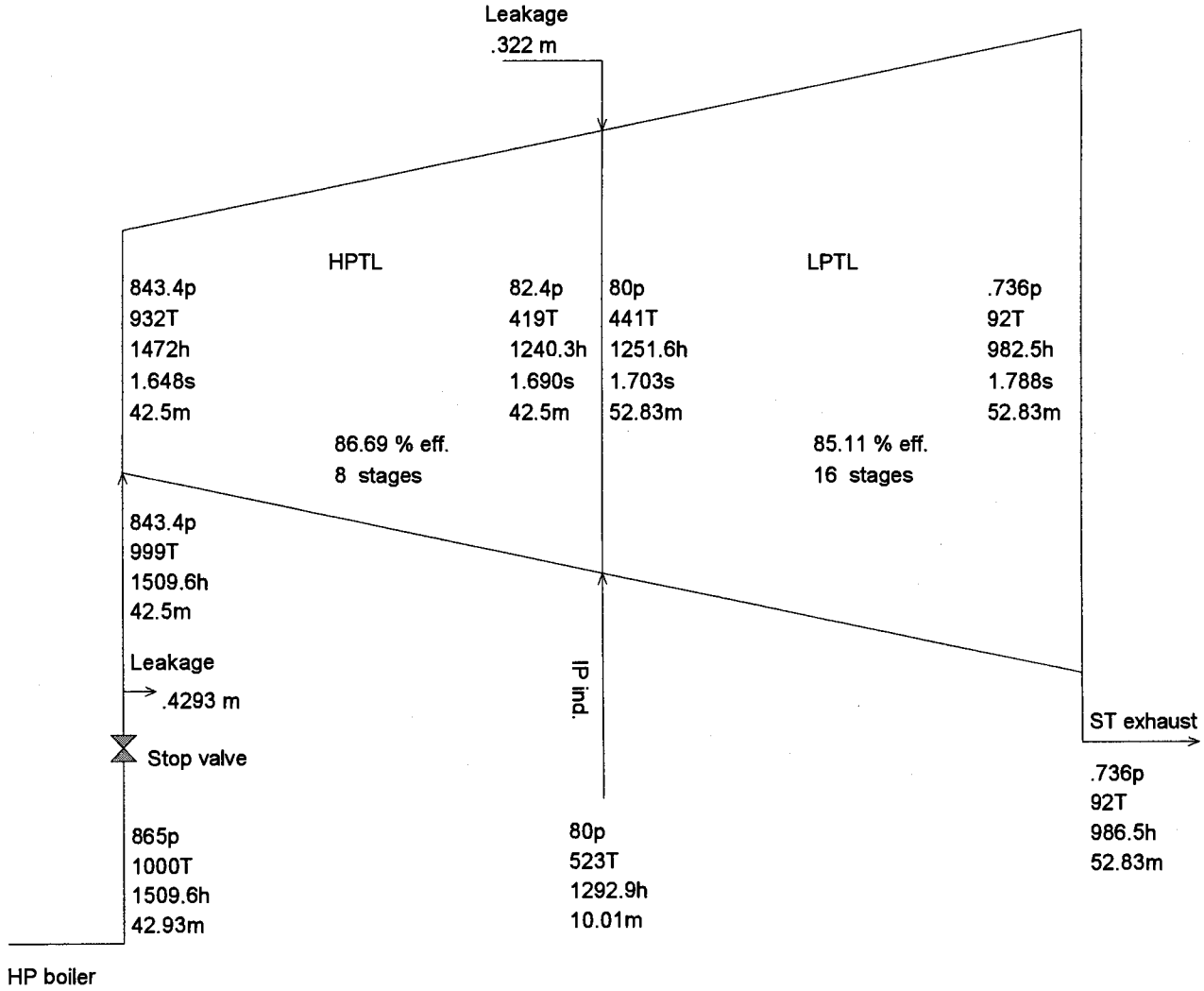

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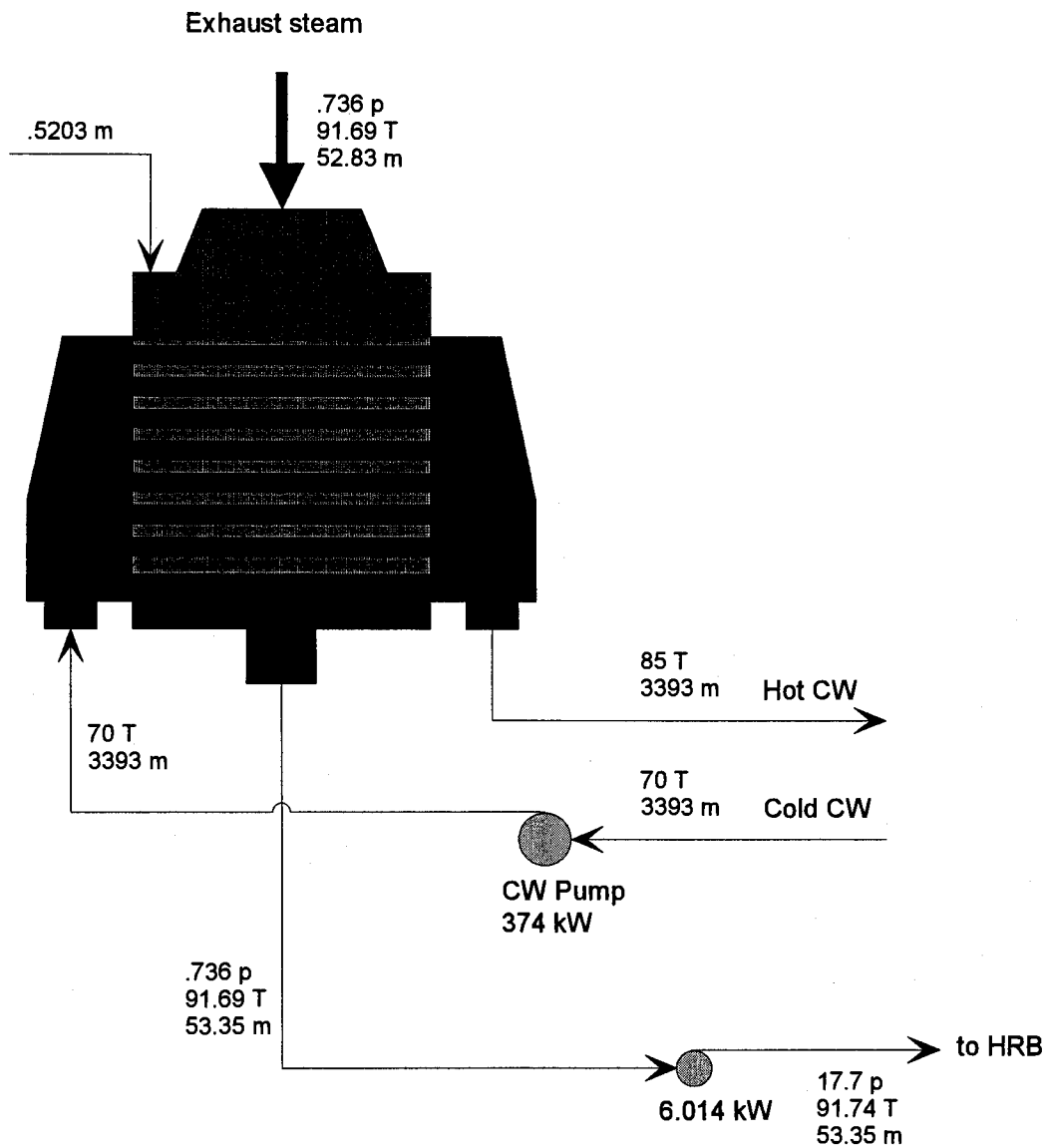
GT PRO for Windows - 1.6 David B. Stauffer

Senegal Barge IPP at Bel Air
Direct seawater cooling



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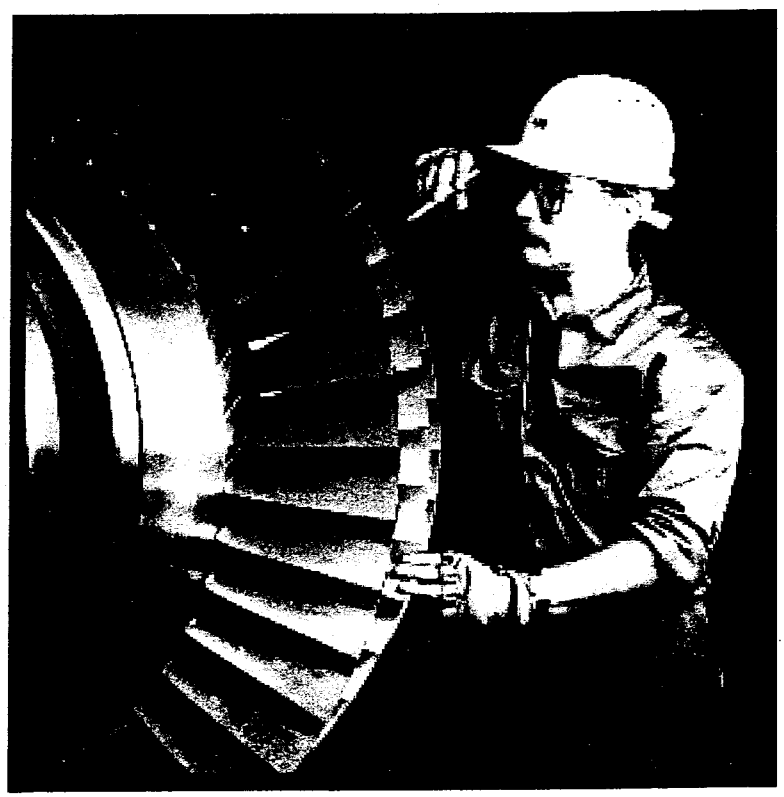
Appendix E: Selected ABB GT8C Reference Guide Information

Select information from the ABB GT8C Reference Guide has been reproduced here for the aid of SENELEC.

ABB

GT8C Gas Turbine Generator Set Reference Guide



Turbine Power Division

ABB Power Generation Inc.

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SINGLE-LINE ELECTRICAL DIAGRAM 6

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ABB POWER GENERATION 8

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ABB POWER GENERATION INC.

ABB GAS TURBINES FOR INDUSTRY AND POWER GENERATION

Deregulation and privatization are leading to greater competition and fundamentally impacting the market and trading conditions.

A power supplier's success criteria will be economical production, efficient distribution, high plant availability, innovation and optimization. ABB is well positioned to help our customers meet the challenges of the changing market. ABB is a world leader in the application of gas turbine technology, our goal is to meet the needs of utilities and industry for clean, efficient power.

ABB's gas turbines are designed to meet a wide range of customer needs: power outputs extend from 2.7 to 265 MW in simple cycle, and 70 to 2,000 MW in combined cycle. Every unit is perfectly balanced for optimum performance in base, intermediate or peak load application, simple or combined cycle operation.

Our combustion technology covers all types of fuel; natural gas, coal gas, low BTU gas, crude or residual oil and naphtha. Dual fuel capability allows fuel switching or simultaneous firing thus minimizing single fuel dependency.

Each unit is fully developed for a wide variety of installation options: single cycle or combined cycle, single and multiple shaft arrangements, indoor or outdoor installation.

The development of ABB gas turbines reflect a continuing efforts to reduce NOx, CO, UHC and particulate emissions. Today our gas turbines meet or exceed all environmental requirements. Our unique lean premix EV burner - a standard for all ABB gas turbines - combines high efficiency with low NOx emission levels of 25 vppm and below (when burning natural gas).

ABB's design and product development philosophy is to progress step by step from a sound technological base. The present gas turbine range incorporates a wealth of innovative design concepts, materials and processes.

All technological advances help provide the most accurate, cost-efficient solutions to customer needs without compromising the environmental performance, efficiency, security and quality on which ABB's reputation as a world leader has been built.

1.1 BACKGROUND OF ABB GAS TURBINES

ABB manufactured the world's first industrial gas turbine generator set in 1939 for a plant in Neuchatel, Switzerland; a machine still in service for emergency standby and peaking duty. Today, ABB's power class line-up is broader and more comprehensive, offering purchasers a wide selection in various power block arrangements. Our 60 Hz series of gas turbines, which is designed specifically for the North American market, consists of the 25 MW Type 10; 43 MW GTX100; 53 MW Type 8C; 84 MW Type 11N1; the 115 MW Type 11N2 and the 183 MW Type 24.

1.1.1 GT 8C Evolution

ABB's medium-size gas turbine, the GT 8, was introduced to the market in 1984. This 48 MW gas turbine incorporated the well-proven design features of ABB's GT 11 and 13 series with technology advances resulting in a high performance unit. Prior to its market introduction, a comprehensive program of running tests was performed on a prototype gas turbine in Switzerland.

The current GT 8 gas turbine is an open-cycle, single-shaft package unit for both the 60 Hz and 50 Hz markets.

The first unit was ordered in 1984 by Shell Nederland Raffinaderij B.V., Rotterdam for the Pernis Cogeneration Plant. In 1986 a slightly modified GT 8 gas turbine underwent trial runs on the company's test stand. The most significant improvements were the method of modular construction and the implementation of the *Egatrol™ 5* microprocessor-based control system. More recently, in 1992, ABB upgraded the current GT 8 to the GT 8C with the following major goals:

- Lower emissions
- Higher output
- Higher efficiency
- Higher availability
- Simpler design for lower O&M costs

These goals are met through the following design improvements:

- Well-proven, silo-type combustor equipped with ABB's dry low NOx EV burner
- New turbine blading with state-of-the-art cooling
- Aerodynamical improvements resulting in decrease of cooling air flow
- Increased firing temperature by approximately 27°F according to ISO definition
- Reduced rotor speed by 100 rpm

1.1.2 The KA8C-1 Single Shaft Reference Plant

To meet plant owners' needs for low initial cost and short schedules, ABB has developed a pre-engineered single-shaft combined cycle power plant. The KA8C-1 reference plant is designed with a dual pressure non-reheat steam cycle which provides high efficiency at an attractive first cost. The reference plant provides short start-up time and is simple to operate. The key advantage of the single-shaft arrangement is its operating simplicity which results in high reliability and availability — as much as 1% higher than those of multi-shaft blocks. Plants cost will be reduced mainly since GT and ST share the generator and other electrical equipment This type of arrangement has been successfully used in the GT8 fleet since 1987.

1.1.3 Reliability and Maintainability

Reliability and maintainability are two of the most important criteria to measure the performance of a power plant today and the GT 8 family of gas turbines clearly delivers in both of these areas.

With a sincere desire for constant improvement, ABB's gas turbine service groups maintain complete records of operational statistics by which the progress of our technology and design can be measured in terms of reliability and maintainability.

Advancements in design and maintainability have continually enhanced and upgraded the GT 8 gas turbines. The reliability statistics of the surveyed worldwide GT 8 fleet reflect a reliability value for the period 1986 through 1990 of 98%.

From its inception, the heavy-duty GT 8 industrial-type gas turbine has proven itself a highly reliable, available and easily maintainable power source for the 50 and 60 Hz markets. The first two units installed in 1985 for Vulcan Chemicals in Geismar, LA, achieved an average reliability and availability of 99.6% and 96.9%, respectively.

1.1.4 Technology

ABB is a leader in industrial gas turbine technology. Areas of expertise in which ABB dominates the market include:

- Dry Emissions Control Technology
- Wet Emissions Control Technology
- Static Starting Technology and Starting Reliability
- Combustor Technology
- Air-Cooled Generator Efficiency and Technology
- Design Reliability
- On-site Maintenance

Compliance with strict environmental regulations is already required on many markets and the awareness of environmental issues is spreading to new regions. ABB has recognized the strategic importance of environmental issues and has taken a lead in the control of gas turbine emissions. In 1988, ABB introduced the first so-called EV burner on the market. To date, the total accumulated experience with this dry, low-emission (DLE) technology amounts to more than 1.6 million operating hours (as per August 1997).

1.1.5 Research and Development

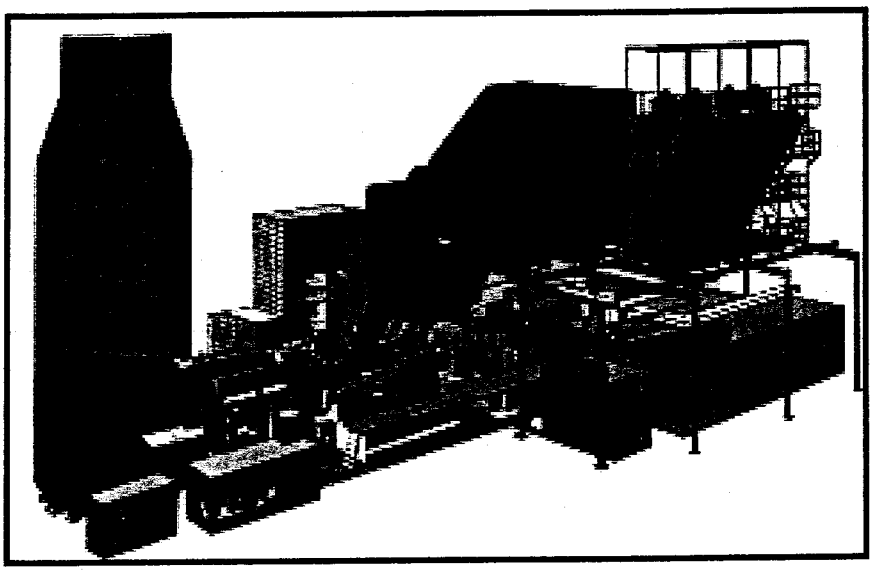
Remaining competitive in today's global economy and positioned for the future are significant goals for ABB. The result is a focused, concentrated approach toward research and development, long considered a key investment at ABB.

ABB has distinctly set itself apart as a leader in this area by more closely aligning R&D with business operations. Decentralized research and development, of which 90 percent takes place in business units rather than in an isolated central lab, has resulted in many early successes. Individual research centers form a strong network known as ABB Corporate Research which is responsible for central R&D for the entire ABB Group. Universities, institutes and venture capital are also core parts of the R&D strategy.

1.2 THE GT 8C

The GT 8C combustion gas turbine generator set adheres to the traditional gas turbine design goals of ABB; simplicity, durability, reliability and ease of maintenance. These goals are accomplished with the GT 8C's heavy-duty construction, single-welded shaft, top-mounted combustor, and dry low NOx EV burners capable of handling various fuel types as well as dual fuel operation. A product of ABB's experience and tradition of excellence, the GT 8C is a proven leader in the power generation industry.

The GT 8C is designed for use either as a simple cycle "peaker" or as the heart of a cogeneration or combined cycle application. It is nominally rated at a power output of 53 MW. During peak firing at low ambient temperatures with water injection, however, power output can be increased to 70 MW. The ABB Dry Low NOx EV Burners operating on natural gas can achieve 25 ppm (15% O_2 corrected) without water or steam injection.



The "cold end drive" unit is configured such that a shaft from the cool inlet section of the gas turbine is used to drive the electric generator. This eliminates thermal expansion and stress concerns that are typical of a "hot end drive" unit. In addition, this configuration allows for an axial exhaust system for simple connection to a waste heat recovery boiler, if required. This provides better flow distribution into the waste heat recovery boiler and lower flow induced vibrations than "hot end drive" units that utilize 90° exhaust diffuser turning vanes.

The GT 8C auxiliaries, control system and electrical equipment are consolidated in standardized modules enabling quick erection and trouble-free maintenance. The GT 8C and its associated modules are easily adaptable to any indoor or outdoor layout configuration for single or multiple units. In all cases, easy access to power plant components for inspection and maintenance is ensured.

The ABB GT 8C offers numerous features which contribute to its success. From rotor durability to combustor design to world class emission control technology, the GT 8C is an industry leader.

1.3 MAIN DESIGN FEATURES OF ABB GAS TURBINES

1.3.1 Rotor Design

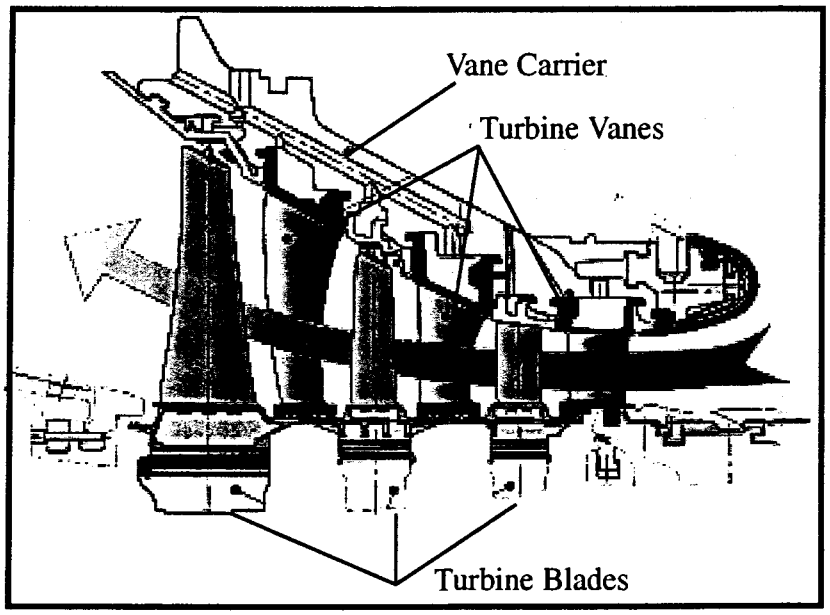
The ABB GT 8C features one integral compressor/turbine rotor formed by welding together forged discs. ABB began welding the rotors of steam turbines and later gas turbines and compressors as early as 1930. This design, continuously refined during the past 60 years, results today in highly successful and more reliable construction. Forged discs, made from low alloy steels, are welded together at their peripheries by an argon and submerged arc method, which is now being used for diameters up to 6 ft. 7 in. and weld thicknesses of up to 8 in. in large steam turbines. Superior quality is assured by means of advanced inspection techniques such as ultrasonic testing which detects surface as well as subsurface flaws.

The solid rotor design is reliable, long lasting and requires minimal maintenance. The absence of mechanical joints, shrink fits or through bolts eliminates the following concerns: stress corrosion cracking of bolts, tension and torque requirements, hub stress or the possibility of relative movements with any parts of the shaft. In addition, the rotor is machined with dovetail slots for the placement of balancing weights. This feature eliminates the need to remove the rotor for balancing even after a complete reblading.

The compressor/turbine rotor is supported by one journal bearing in the turbine end and one journal/thrust bearing in the compressor end. This highly reliable, two-bearing design allows access for service and inspection of the bearings without removing the gas turbine rotor or casing, in addition to eliminating cooling considerations, lube oil leaks and critical internal alignment that are associated with the "hot" bearing in a three-bearing design.

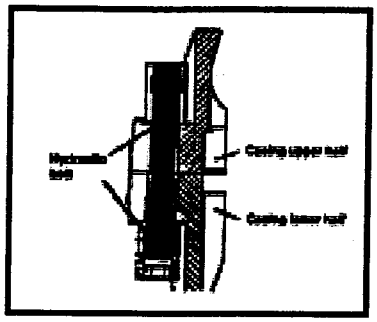
1.3.2 Blade Design

The blade and vane material used by ABB for the GT 8C 12-stage axial compressor is highly resistant to corrosion. ASTM A-504 and A-565 superior quality, high chromium content steels are employed in stages 1-5 and 6-12, respectively. These particular blade and vane materials require no coatings, demonstrate longer life than traditional coated materials, and offer significant savings in maintenance cost and time by eliminating the need to recoat.



The utilization of reaction blading produces a minimum distribution of losses. The first two stages of the GT 8C compressor are transonic with blading design based on low aspect ratio technology.

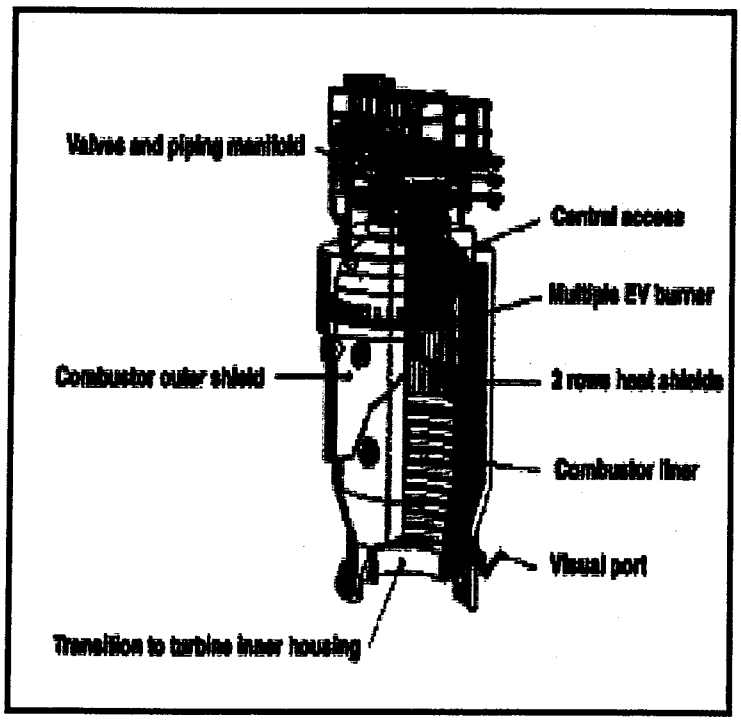
Variable compressor inlet guide vanes can be used for efficient part load operation in cogeneration and combined cycle plants. By closing the guide vanes, air flow through the gas turbine is reduced. During part load operation, this results in a consistently high exhaust gas temperature which is necessary for an effective steam cycle.



Inconel 738LC and 939, nickel alloys tolerant of extremely high temperatures, is the primary material used throughout the GT 8C turbine section. The first two turbine stages employ impingement, convective and film cooling utilizing compressor discharge air. This relatively cool compressor air, flows through intricately designed internal cooling passages, enabling the blades and vanes to withstand the extremely hot combustor exit gases.

1.3.3 Casings

The GT 8C uses a horizontally split compressor and turbine case. The casing halves are secured together with hydraulically stretched bolts. These bolts offer important advantages over conventional bolts in terms of both maintenance time and cost. A hydraulic stretcher is used to quickly and easily remove the bolts, reducing case separation time from as much as several days to as little as a few hours. In addition, this design eliminates the need for heating torches in bolt removal and offers the advantage of exact bolt torque throughout the case.



1.3.4 Combustor

The unique top-mounted, single-silo combustor used in ABB supplied gas turbines has proven itself as one of the most reliable, long lasting, and low maintenance combustors in the industry. This large volume design results in an even temperature distribution at the turbine inlet. In addition, the ability for personnel to physically enter and access the inside of the combustion chamber and turbine, up to the first row of vanes and blades, simplifies maintenance and inspection tasks. Nineteen (19) Low NOx

EV double-cone burners, fitted on the top of the combustor, are capable of operation on gaseous or liquid fuels both in single or dual configurations. Water injection is required for NOx control with liquid fuel operation.

1.3.5 Emission Control

ABB, one of the industry leaders in the field of dry emission control, began development of clean low emission burner technology in the late '70s and commissioned its first Dry Low NOx gas turbine in 1984 on a 100 MW GT 13B unit in Germany. At that time, the first generation "lean pre-mix" burner achieved a NOx level of 36 ppmvd (15% O_2 corrected). Currently, the GT 8C EV burners achieve a Dry Low NOx emission level of 25 ppmvd (15% O_2 corrected) when operating on natural gas. ABB's staging/piloting concept provides the capability to maintain low NOx levels over a wide operating range. Total ABB experience with Dry Low NOx combustors now exceeds 1.6 million hours (as of August 1997).

1.3.6 Reduction Gear

The MAAG reduction gear installed between the gas turbine and the generator is equipped with single-helical teeth. The Gas turbine and pinion are rigidly coupled by an intermediate shaft. The low-speed shaft of the gear and the generator are also connected by an intermediate shaft. This block-mounted, compact reduction gear also drives the main lube oil pump. Various components of the lube oil system are mounted on the base plate, which forms the lube oil tank.

1.3.7 Starting System

Through the use of a Static Frequency Converter (SFC), ABB utilizes the generator as a synchronous motor for starting. By varying the frequency input to the generator, the SFC accelerates the gas turbine to a self-sustaining speed. This starting system design was pioneered by ABB in 1974 and is currently a state-of-the-art starting device. With few mechanical components, the SFC is highly reliable, requires little maintenance and offers the advantage of having no limitation on the number or time interval of restarts. In addition, a single unit can be used to start several gas turbines. The ABB starting system has the ability to go from gas turbine ignition to generator synchronization speed in twenty minutes, or in as little as ten minutes, if required.

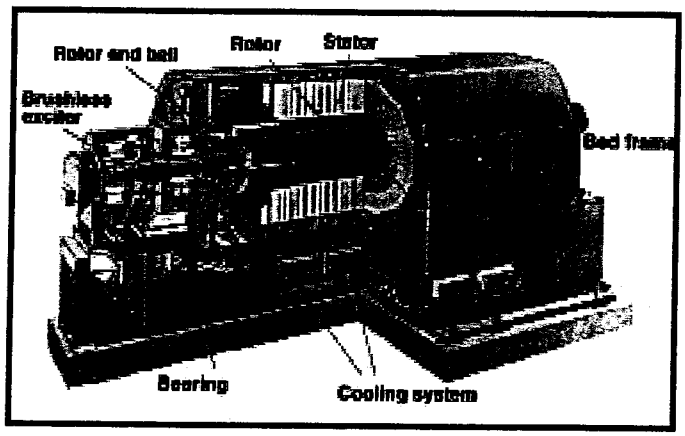
1.3.8 Generator

Standard equipment on the GT 8C is the 74.5 MVA TEWAC two-pole, three-phase synchronous Totally Enclosed Water-to-Air Cooled electric generator driven at 3600 RPM. The generator features a closed air circuit which performs all the necessary cooling for the stator and rotor. Class F, Micadurâ insulation is used throughout the generator. Axial fans move the air inside the stator, axially along the rotor, then return the air across a bank of water coolers located in the base of the generator. The TEWAC design eliminates the need for inlet air filters and silencers commonly found in open air-cooled units, offers long life, cleanliness and low maintenance costs.

Power Station Control proven plant control and monitoring system, is employed for signal processing and conversion, open loop and closed loop control, turbine protection, and annunciation

for the 8C gas turbine generator unit.

The standardized modular system is designed to meet all power station process requirements and provide coordination of all functional components. The overall control concept includes a redundant protection system which increases availability and operational safety of the gas turbine generator unit. *Egatrol*™ allows the unit to be operated automatically from standstill through start-up, run-up, loading, normal oeration, shut-down, cool down, and back to standstill.



1.4 MODES OF OPERATION

The GT 8C is designed for fully automatic start-up, operation and shut-down. The unit is suitable for daily starts to cover peak demands as well as for continuous base load operation. The power plant is designed for parallel operation with other generator units or as an isolated and independent station.

1.4.1 Starting

The gas turbines can be started using normal or fast starting modes. The starting option is selected at the initiation of an automatic start. Normal and fast start is a function of ramp rate from synchronization to full load.

1.4.2 Operation

Depending on the grid connection, the unit can be controlled by load, turbine inlet temperature or frequency. The unit can be loaded either automatically or manually to any preset point up to peak load. In addition, the operator can manually vary the load over the entire power range from the control panels located in the control enclosure. Load can be varied from a remote location by means of a remote control desk in cases where this equipment is supplied.

1.4.3 Shutdown

On normal controlled shutdown, the generator load is automatically reduced to zero. After coast down, the rotor barring system engages automatically for operation during cool down. The gas turbine can be restarted by the static frequency converter at any time during the cooling period.

GT8C - Proven Technology

Reference List

Plant	Customer	Country	Fuel	Application	No. of Units	In Oper.	Plant Size [MW]
MARTINLAAKSO	Vantaan Sähkölaitos OY	FI	NG, Light Oil	CCG	1	94	200
GTD DÖTTINGEN	NOK	CH	Light Oil	SC	1	95	53
WAPENVELD	Berghuizer Papierfabriek N.V.	NL	NG	CCG	1	95	71
ST. PETERSBURG	EVU Lenenergo	RU	NG	CG	1	96	53
NOVOGORKOVSKAYA 1	RAO EES/EVU Nishnovenergo	RU	NG, Light Oil	CG	1	96	53

GT8C - Proven Technology

Reference List

Plant	Customer	Coun-try	Fuel	Ap-pli-cation	No. of Units	In Oper.	Plant Size [MW]
ROW	Rheinische Olefinwerke	DE	NG, Light Oil	CG	1	96	53
GVK (Jegurupadu)	GVK Industries	IN	NG, Naphtha	CC	3	96	235
YAKUTSK	Yakutskenergo	RU	NG	CG	2	97	53
OMSK	Omskenergo	RU	NG	CG	3	98	53
IP COGEN	Industrial Power Company Ltd.	TH	NG	SSPT CCG	2	97	2 x 71

GT8C - Proven Technology

Reference List

Plant	Customer	Coun-try	Fuel	Ap-pli-cation	No. of Units	In Oper.	Plant Size [MW]
ZHANAZHOL	Zhanaturbo Gas	KAS	Flare gas	SC	3	97	3x53
GORZOW	EC Gorzów	PL	NG	CG	1	98	53
NIPPON DENRO	Nippon Denro Yspat	IN	Naphtha	Topping Cycle	2	98	354
SENGKANG	PT Energi	ID	NG	CC	2	97	156.2
Kladno	ECK Generating/ ABB Brno	CZ	NG / #2 oil	CG	1	98	53

GT8C - Proven Technology

Operating Experience

Plant	Customer	Ctry	Fuel	Use	1st Ignition	Fired Hours	Starts
Martinlaakso	Vantaan Sähkölaitos	FI	NG+ No2	CC-Distr.H.	11-94	13'754	134
GTD Döttingen	NOK	CH	Light Oil	SC reserve	10-95	269	81
Wapenveld	Berghuizer Papierfa.	NL	NG	CC-Cogen	07-95	11'833	59
Placerita 1 *	AES Placerita Inc.	US	NG	CC-Cogen	11-95	8'689	89
Chevron 1 *	Chevron Refinery	US	NG	Cogen	03-96	8'841	19
Chevron 2 *	Chevron Refinery	US	NG	Cogen	04-96	7'195	18
Massena *	Sithe Energies	US	NG	CC	05-96	8'730	31
Elmwood Park *	Prime Energy Ltd.	US	NG	CC-Cogen	05-96	7'703	23
ROW	Rheinische Olefinw.	DE	NG + No2	Cogen	05-96	5'219	88
GVK1 (Jegurupadu)	GVK Industries	IN	NG + Naph.	CC	06-96	5'801	68
GVK2 (Jegurupadu)	GVK Industries	IN	NG + Naph.	CC	10-96	3'701	38
GVK3 (Jegurupadu)	GVK Industries	IN	NG + Naph.	CC	12-96	2'967	34
Accumulated						**84'702**	**682**

* = *GT8 unit uprated with GT8C turbine blading / experience since uprating*

ABB

Series Experience

	Total No. of units	Fired Hours
GT8 Series Experience	**49**	**>1'100'000**
GT8 Simple Cycle Units	6	
GT8 Combined Cycle / Cogen Units	18	
GT8C Simple Cycle Units	4	
GT8C Combined Cycle / Cogen Units	21	
All Units	Total No. of Starts	>10'000

Fuel:	Application of cogeneration:		Remarks:
BFG = Blast furnace gas	PP = Pulp & paper, paper mill	MP = Metal production	DH = District heating
LNG = Liquefied natural gas	PC = Petro chemical	DES = Desalination	RP = Repowering
LPG = Liquefied petroleum gas	INP = Industrial park	CON = Consumables	SF = Supplementary firing
	SE = Steam extraction		

TOTAL				134 KA units	38205 KA MW	272 GT units				
Ref. No.	Plant Name	Country	n Operation	KA-series	P_{total} (MW)	P_{GT} (MW)	Fuel GT	Appl. of cogen.	Scope of supply	Remarks
126	Tung Hsiao	Taiwan	2000	1 x KA11N-2	335	2 x 115	Diesel / Natural gas	–	Turnkey	–
125	Dock Sud	Argentina	1999	1 x KA26-2	775	2 x 241	Natural gas / diesel	–	GT + ST + Eng.	–
124	Taranaki	New Zealand	1998	1 x KA26-1	360	1 x 241	Natural gas	–	Turnkey	–
123	RDK 4S	Germany	1998	1 x KA26-1	360	1 x 241	Natural gas	–	GT	RP
122	South Humber Bank	Great Britain	1998	1 x KA13E2-2	510	2 x 166	Natural gas	–	Turnkey	–
121	API IGCC	Italy	1998	1 x KA13E2-1	275	1 x 175	Syngas / diesel	PC	Power Island	–
120	Marmara	Turkey	1998	1 x KA13E2-2	470	2 x 160	Natural gas / diesel	–	Turnkey	–
119	Nippon Denro	India	1998	1 x KA8C-2	388	2 x 53	Naphtha	MP	Turnkey	SF
118	Rocksavage	Great Britain	1997	1 x KA26-2	730	2 x 241	Natural gas	–	GT + ST	–
117	Poryong	South Korea	1997	4 x KA24-2	2020	8 x 165	Natural gas / diesel	–	GT + ST + HRSG	–
116	Muara Tawar CC	Indonesia	1997	1 x KA13E2-3	1100	6 x 145	Natural gas / diesel	–	Turnkey	–
115	South Humber Bank	Great Britain	1997	1 x KA13E2-3	750	3 x 166	Natural gas	–	Turnkey	–
114	RWE / BASF	Germany	1997	1 x KA13E2-2	470	2 x 160	Natural gas / diesel	INP	Turnkey	–
113	Bao Shan LBtu	China	1997	1 x KA11N2-1	150	1 x 110	BFG	MP	GT + ST + Generato	–
112	Zhao Qing	China	1997	1 x KA13D-2	300	2 x 100	Heavy oil / diesel	–	Turnkey	
111	IP Cogen	Thailand	1997	2 x KA8C-1	151	2 x 53	Natural gas	INP	Turnkey	–
110	Sengkang	Indonesia	1997	1 x KA8C-2	149	2 x 53	Natural gas	–	Turnkey	–
109	Kotka	Finland	1997	1 x KA10-1	48	1 x 25	LNG / diesel	PP	GT + ST	–
108	Bergen op Zoom	The Netherlands	1997	1 x KA10-1	34	1 x 25	Natural gas	INP	Turnkey	–
107	Frankfurt Oder	Germany	1997	1 x KA10-1	53	1 x 25	LNG	–	Turnkey	DH
106	Meishi II	China	1996/97	1 x KA13E2-1	237	1 x 170	Diesel	–	Turnkey	–
105	Lumut A + B	Malaysia	1996/97	2 x KA13E2-3	1300	6 x 150	Natural gas / diesel	–	Turnkey	–
104	Berlin Mitte	Germany	1996	1 x KA13E2-2	380	2 x 136	Natural gas / diesel	–	Turnkey	DH
103	Termobarranquilla	Colombia	1996	1 x KA11N2-2/3	750	5 x 100	Natural gas	–	Turnkey	–
102	Jegurupadu / GVK	India	1996	1 x KA8C-3	235	3 x 53	Natural gas / naphtha	–	Turnkey	–
101	Neu Brandenburg	Germany	1996	2 x KA10-1	74	2 x 25	LNG	–	Turnkey	DH
100	Dessau	Germany	1996	1 x KA10-1	43	1 x 25	Natural gas	–	Turnkey	DH
99	Gera Nord I + II	Germany	1996	1 x KA10-2	78	2 x 25	LNG	–	Turnkey	DH
98	Klazinaveen I + II	The Netherlands	1996	1 x KA10-2	71	2 x 25	Natural gas	CON	Turnkey	–
97	Erica I + II	The Netherlands	1996	1 x KA10-2	71	2 x 25	Natural gas	CON	Turnkey	–
96	Rostock I-III	Germany	1996	3 x KA10-1	120	3 x 25	Natural gas / diesel	–	Turnkey	DH
95	Potsdam	Germany	1996	1 x KA10-2	84	2 x 25	Natural gas	–	GT + Eng.	DH
94	Naestved	Denmark	1996	1 x KA10-1	39	1 x 25	Natural gas	–	GT + Eng.	DH
93	Kuala Langat	Malaysia	1995	1 x KA13E2-3	670	3 x 140	Natural gas / diesel	–	Turnkey	–

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LPG = Liquefied petroleum gas	INP = Industrial park	CON = Consumables	SF = Supplementary firing
	SE = Steam extraction		

92	Diemen 33	The Netherlands	1995	1 x KA13E2-1	240	1 x 160	Natural gas	–	Turnkey	DH
91	West Windsor	Canada	1995	1 x KA11N-1	120	1 x 80	Natural gas	–	Power Train	SF
90	Bundang II	South Korea	1995	1 x KA11N-3	320	3 x 78	Natural gas / diesel	–	Turnkey	DH
89	Wapenveld	The Netherlands	1995	1 x KA8C-1	69	1 x 53	Natural gas	PP	GT + ST + Eng.	–
88	Martinlaakso	Finland	1995	1 x KA8C-1	192	1 x 53	Natural gas / diesel	SE	GT + Eng.	RP/SF/DH
87	Borculo I + II	The Netherlands	1995	1 x KA10-2	65	2 x 25	Natural gas	CON	Turnkey	–
86	Tanjung Priok	Indonesia	1994/95	2 x KA13E-3	1140	6 x 128	Natural gas / diesel	–	Turnkey	–
85	Linköping	Sweden	1994/95	1 x KA10-1	50	1 x 25	Diesel	SE	GT + ST + Eng.	DH
84	Lage Weide 6	The Netherlands	1994	1 x KA13E2-1	248	1 x 158	Natural gas	–	GT + ST + HRSG +	DH
83	Deeside	Great Britain	1994	1 x KA13E2-2	508	2 x 166	Natural gas / diesel	–	Turnkey	–
82	Gandhar	India	1994	1 x KA13E-3	657	3 x 144	Natural gas	–	Turnkey	–
81	Foshan	China	1994	1 x KA13D-2	280	2 x 94	Heavy oil / diesel	–	Turnkey	–
80	Shunde	China	1994	1 x KA13D-2	280	2 x 94	Heavy oil / diesel	–	Turnkey	–
79	Lakewood	New Jersey, USA	1994	1 x KA11N-2	236	2 x 79	Natural gas / diesel	–	GT + ST + HRSG +	–
78	Limay Bataan A/B	Philippines	1994	2 x KA11N-3	680	6 x 75	Heavy oil / diesel	–	Turnkey	–
77	Eerbeek I + II	The Netherlands	1994	1 x KA10-2	66	2 x 25	Natural gas	PP	GT + ST + Eng.	–
76	Pierre de Plan	Switzerland	1994	1 x KA10-1	33	1 x 25	Natural gas	–	GT + ST + HRSG +	DH
75	VKC3 Helmond	The Netherlands	1994	1 x KA10-1	37	1 x 25	Natural gas	CON	GT + ST + Eng.	–
74	Dobbestroom	The Netherlands	1994	1 x KA10-1	37	1 x 25	Natural gas	CON	Turnkey	–
73	Heineken	The Netherlands	1994	1 x KA10-1	37	1 x 25	Natural gas	CON	GT + ST + Eng.	–
72	Killingholme A	Great Britain	1993	1 x KA13E-3	652	3 x 145	Natural gas	–	Turnkey	–
71	Deep	Dubai	1993	1 x KA13D-1	135	1 x 86	Natural gas / diesel	MP	Turnkey	–
70	Orlando	Pennsylvania, US	1993	1 x KA11N-1	120	1 x 83	Natural gas	–	GT + ST + HRSG +	–
69	Farmington	New Mexico, US	1993	1 x KA10-1	37	1 x 83	Natural gas / diesel	–	GT + ST + HRSG +	DH
68	Oberschmitten	Germany	1993	1 x KAM-1	13	1 x 10	Natural gas	PP	GT	RP
67	Opel Eisenach	Germany	1993	1 x KAM-1	20	1 x 10	Natural gas / diesel	INP	GT + ST + Eng.	–
66	Alba	Bahrain	1992/93	2 x KA13D-3	700	6 x 81	Natural gas / diesel	MP	Turnkey	–
65	Bundang	South Korea	1992/93	1 x KA11N-5	565	5 x 73	LNG / diesel	–	GT + ST + HRSG +	DH
64	Anyang	South Korea	1992/93	1 x KA11N-4	462	4 x 73	LNG / diesel	–	GT + ST + HRSG +	DH
63	Chania	Greece	1992/93	1 x KA8-2	134	2 x 45	Diesel	–	Turnkey	–
62	Rabigh	Saudi Arabia	1992	2 x KA11-4	696	8 x 55	Crude oil	–	Turnkey	–
61	Tung Hsiao 4/5	Taiwan	1992	2 x KA11N-3	660	6 x 74	Heavy oil / diesel (LN	–	GT + ST + HRSG +	–
60	Massena	New York, USA	1992	1 x KA8-1	82	1 x 52	Natural gas / diesel	–	GT + ST + Eng.	SF
59	Roosecote	Great Britain	1991	1 x KA13E-1	224	1 x 150	Natural gas / diesel	–	Turnkey	–
58	RPE Commerce	Virginia, USA	1991	1 x KA11N-2	220	2 x 80	Natural gas / diesel	–	GT	–
57	Angelholm	Sweden	1991	1 x KA10-1	29	1 x 25	Natural gas	–	Turnkey	DH

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	SE = Steam extraction		

56	Karlskoga	Sweden	1991	1 x KA10-1	35	1 x 25	LPG / natural gas	–	Turnkey	DH
55	Biberist	Switzerland	1991	1 x KAM-1	23	1 x 9	Natural gas / diesel	PP	GT + Eng.	–
54	Anta	India	1990	1 x KA13D-3	414	3 x 88	Natural gas / naphtha	–	Turnkey	–
53	Hopewell	Virginia, USA	1990	1 x KA11N-3	356	3 x 87	Natural gas / diesel	–	Turnkey	–
52	Kalaeloa	Hawaii, USA	1990	1 x KA11N-2	200	2 x 74.5	Heavy oil / diesel	–	Turnkey	–
51	Midland	Michigan, USA	1990	1 x KA11N-12	1370	12 x 87	Natural gas	INP	GT + ST + Eng.	SF
50	Trakya 3/4	Turkey	1989/90	2 x KA13D-2	600	4 x 100	Natural gas	–	Turnkey	–
49	MK 12 (Pegus 12)	The Netherlands	1989	1 x KA13E-1	225	1 x 150	Natural gas	–	Turnkey	DH
48	Hazleton	Pennsylvania, US	1989	1 x KA11-1	135	1 x 72	Natural gas / diesel	INP	Turnkey	–
47	Purmerend	The Netherlands	1989	1 x KA8-1	69	1 x 48	Natural gas	–	Turnkey	DH
46	Elmwood Park	New Jersey, USA	1989	1 x KA8-1	68	1 x 50	Natural gas / diesel	PP	Turnkey	–
45	Galileistraat	The Netherlands	1989	1 x KA8-3	222	3 x 50	Natural gas	–	Turnkey	DH
44	Aspropyrgos I + II	Greece	1989	1 x KA10-2	50	2 x 17	Refinery gas	PC	GT + ST + Eng.	–
43	Hemweg 7/8	The Netherlands	1988	1 x KA13E-1	600	1 x 135	Natural gas	–	GT + ST + Eng.	DH/SF
42	AES Placerita	California, USA	1988	1 x KA8-2	106	2 x 45	Natural gas	INP	Turnkey	–
41	Kabul 3/4	Afghanistan	1988	1 x KA9-2	85	2 x 28	Diesel	–	Turnkey	–
40	Helmond 2	The Netherlands	1988	OEM	28	1 x 21	Natural gas	–	ST + Eng.	–
39	Trakya 1/2	Turkey	1987/88	2 x KA13D-2	600	4 x 100	Natural gas	–	Turnkey	–
38	Lage Weide 5	The Netherlands	1987	1 x KA11-1	270	1 x 65	Natural gas	–	GT + Eng.	DH
37	Almere	The Netherlands	1987	1 x KA8-1	69	1 x 48	Natural gas	–	Turnkey	DH
36	HKW Kassel	Germany	1987		30	2 x 10	Natural gas	–	ST	DH
35	El Ameriya	Egypt	1986	1 x KA9-1	46	1 x 28	Natural gas / diesel	–	Turnkey	–
34	Lujan de Cuyo	Argentina	1986	1 x KA9-2	81	2 x 26	Natural gas / diesel	–	Turnkey	–
33	El Sauz	Mexico	1985	1 x KA11-3	232	3 x 51	Natural gas / diesel	–	Turnkey	–
32	MK 11 (Pegus 11)	The Netherlands	1984	1 x KA9-2	112	2 x 36	Natural gas / diesel	–	Turnkey	DH
31	Helmond 1	The Netherlands	1984	OEM	28	1 x 21	Natural gas	–	ST + Eng.	–
30	Leiden	The Netherlands	1983	OEM	92	2 x 30	Natural gas	–	ST	–
29	Federal Paper	California, USA	1983	OEM	30	1 x 24	Natural gas	–	ST	–
28	Harculo 6	The Netherlands	1982	OEM	330	1 x 80	Natural gas / diesel	–	ST	–
27	Hagen Kabel	Germany	1982	1 x KA13D-2	230	2 x 75	Natural gas / diesel	SE	Turnkey	–
26	Tung Hsiao 3	Taiwan	1982	1 x KA11-3	273	3 x 60	Heavy oil / diesel	–	GT + ST + HRSG +	–
25	HKW Barmen	Germany	1982	OEM	108	2 x 35	Natural gas	–	ST	–
24	Korneuburg B	Austria	1980	1 x KA13D-1	128	1 x 81	Natural gas	–	Turnkey	–
23	Beluga	Alaska, USA	1980	1 x KA11-2	177	2 x 60	Natural gas	–	GT + ST + Eng.	–
22	MK 10 (Pegus 10)	The Netherlands	1979	1 x KA9-2	100	2 x 31	Natural gas / diesel	–	GT + ST + Eng.	–
21	Lausward E	Germany	1977	2 x KA13-1	445	2 x 72.5	Natural gas / diesel	–	GT + ST + Eng.	–

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20	Mainz 2	Germany	1977	1 x KA13D-1	335	1 x 65	Natural gas / diesel	–	GT + Eng.	–
19	Elverlingsen	Germany	1976	1 x KA13D-2	209	2 x 74	Diesel	–	GT + ST + Eng.	–
18	Braintree	Massachusetts, U	1976	1 x KA11-1	80	1 x 55	Diesel / heavy oil	–	GT + ST + Eng.	–
17	Monclova 5	Mexico	1976	1 x KA11-2	40	2 x 15	BFG	–	GT + ST + Eng.	–
16	Monclova 2	Mexico	1976	1 x KA11-2	38	2 x 14	Natural gas	–	GT + ST + Eng.	–
15	Donge	The Netherlands	1975	1 x KA13D-1	118	1 x 75.5	Natural gas	–	GT + ST + HRSG +	–
14	Timelkam	Austria	1975	1 x KA13D-1	107	1 x 72	Heavy oil	–	GT + ST + Eng.	–
13	Veltheim 4	Germany	1975	1 x KA13-1	366	1 x 51	Natural gas / diesel	–	GT + ST + Eng.	–
12	Long Beach	California, USA	1974/75	1 x KA11-7	581	7 x 62	Natural gas / diesel	–	GT + Eng.	–
11	Emsland	Germany	1974/75	OEM	2 x 455	1 x 55	Natural gas	–	ST	–
10	Theiss A/B	Austria	1974	1 x KA120	232	2 x 70	Natural gas	–	GT + Eng.	–
9	Marbach	Germany	1974	1 x KA13-1	315	1 x 55	Diesel	–	GT + ST	–
8	Robert Frank	Germany	1973	1 x KA13-1	510	1 x 55	Natural gas	–	Turnkey	–
7	Gersteinwerk	Germany	1973	OEM	4 x 455	1 x 55	Natural gas	–	ST + Eng.	–
6	Hüls KW 3	Germany	1973	1 x KA13-2	165	2 x 55	Natural gas	–	Turnkey	–
5	Vitry s. Seine	France	1970/71	1 x KA13-2	2 x 322	2 x 42	Natural gas	–	GT + ST	–
4	Brownsville	Texas, USA	1968	1 x KA11-1	22	1 x 15	Natural gas / diesel	–	GT + Eng.	–
3	Cornigliano	Italy	1963	1 x KA12	28	1 x 16	BFG	–	GT + ST + Eng.	–
2	Korneuburg A	Austria	1961	2 x KA12	75	2 x 25	Natural gas	–	GT + ST + Eng.	–
1	Dudelange	Luxembourg	1956	1 x KA12	19	1 x 5.5	BFG	–	GT + ST + Eng.	–

3.

TECHNICAL DATA

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3.1. MAIN MACHINE SET

GAS TURBINE BLOCK

General	
Manufacturer	ABB
Type	GT8C
Number / type of rotors	1 / welded integral comp/turbine
Operating speed	Turbine 6212 / Gen 3600 rpm
Trip speed	Turbine 6833 / Gen 3960 rpm
Critical speeds	
Gas turbine (1st/2nd)	1700 / 2600 rpm
Generator (1st/2nd)	1700 / 2600 rpm
Moment of inertia (J)	
Turbine, gear, generator	34,884 lb ft^2
Design ambient temperature range	- 49°F to 131°F
Number of compressor stages	12
Compressor ISO pressure rating	15.7
Compressor bleed stages	3, 6, 10
Number of turbine stages	3
Number of cooled turbine stages	2

Materials	
Turbine casing	A 356 Grade G
Turbine vane carrier	A 356 Grade 10
Inner casing	IN 617
Forged pieces for the rotor	A 418
Turbine blades, rows 1-3	IN 738 LC
Turbine vanes, rows 1-3	IN 939
Compressor casing	A 536 Grade 60-40-18
Compressor vane carrier	A 536 Grade 60-40-18
Compressor blades, row 1	Titanium aluminide
Compressor blades, rows 2-5	A 705
Compressor blades, rows 6-12	A 565
Compressor variable inlet guide vanes	Titanium aluminide
Compressor vanes, rows 1-5	A 504
Compressor vanes, rows 6-12	A 565
Compressor outlet guide vane row	A 565

Combustor Block with EV Burners	
Manufacturer	ABB
Combustor Type / Number	silo, top-mounted / 1
Number of combustors	1
Number of EV burners	19
Type of burners	conical premix

Gear Block	
Manufacturer	MAAG
Type	G - 725
Type of gearing	single helical
Speed of the main shaft, turbine side	6212 rpm
Speed of the main shaft, generator side	3600 rpm
Speed of the main lube oil pump	1367 rpm
Gear ratio	2.07
Mechanical limit (gearbox base load)	70 MW
Casing design	horizontally split

Generator	
Series / size of generator	WY 16Z-068LL
Apparent power*	87 MVA / 74.5 MVA
Power factor	0.85
Voltage at terminals	13.8 kV ± 5 %
Current*	3640 A / 3117 A
Operating speed	3600 rpm
Standards standard model	ANSI C50.10, C50.13, C50.14
Standards, if desired	IEC, BS, VDE, SEV
Insulation class	F
Degree of protection	NEMA 12
Type of cooling	TEWAC
Coolers	Closed-circuit air / water heat exchangers; coolers integrated into the bottom section of the stator casing
Material of coolers, Pipes	Cu Ni 10 Fe
Material of coolers, Fins	Al
Material of coolers, pipe floor	Cu Zn 38 Sn Al
Material of cooler, Water Chamber	GGG40
Terminal outlets	6 terminals, on top of casing at non-driving end
Excitation	Brushless AC exciter (WBF6-4K) with rotating diodes, mounted overhung on the generator shaft

* According to ANSI temperature rise for: Class F / Class B

Exciter	
Manufacturer	ABB
Type	WBF6-4K
Rating continuous	437 kW
Rating for 10 sec	812 kW
Voltage continuous	372 V
Voltage for 10 sec	507 V
Current continuous	1175 A
Current for 10 sec	1602 A
Temperature of cooling air	104° F
Standards	IEC, ANSI
Speed	3600 rpm

3.2. MECHANICAL SYSTEMS

Air Intake System	
Type of air filter	pulse / self cleaning or two stage
Volume of air intake	approx. 388 lb/s
Air pressure for cleaning the filter	87 - 117 psig
Silencer	Baffle, absorber

Exhaust System	
Stack height (stack optional)	70 ft
Diameter at stack opening	131.5"
Thickness of insulation bottom half	approx. 7"
Thickness of insulation top half	approx. 2"
Material in stack inner liner	SS-409
Insulation	Mineral wool
Cladding	AlMg 3

Lube and Power Oil System	
First lube oil filling	approx. 5000 gal

Lube Oil Tank	
Capacity main tank	3300 gal
Capacity auxiliary tank	1700 gal

Lube Oil Heater in Main Tank	
Number of heating elements	5
Type	Submerged electrodes
Power supply (AC)	480 V
Total rated output	25 kW

Lube Oil Heater in the Auxiliary Tank	
Number of heating elements	2
Type	Submerged electrodes
Power supply (AC)	480 V
Total rated output	8.7 kW

Oil Vapor Exhaust Fan	
Power supply (AC)	480 V
Total rated output	1.7 kW

Main Lube Oil Pump	
Type	Gear pump
Drive	Direct (mounted on gear block)
Speed	1367 rpm
Nominal absolute pressure	100 psi
Pump capacity at 87 psi	14 gal/s

Lube Oil Cooler	
Type	Plates
Cooling medium	Water

Auxiliary Lube Oil Pump	
Type	Centrifugal pump
Power supply (AC)	480 V
Speed (motor)	3550 rpm
Rated power (motor)	86.25 kW
Nominal absolute pressure	71.1 psi
Pump capacity at 71.1 psi	12.48 gal/s

Lube Oil Filter	
Type	Twin filter
Max. throughflow	13.33 gal/s
Min. extraction fineness	10 micron

Emergency Cooling Oil Pump	
Type	Screw pump
Power supply (DC)	125 V
Speed	2900 rpm
Rated power (motor)	1.13 kW
Nominal absolute pressure	8.7 psi
Pump capacity	0.48 gal/s

Jacking Oil Pump	
Type	Reciprocating pump
Power supply (DC)	125 V
Speed	1000 rpm
Rated power (motor)	2.2 kW
Nominal absolute pressure	11,600 psi

Power Oil Tank	
Capacity	264 gal

Power Oil Heater	
Number of heating elements	4
Type	Submerged electrodes
Power supply (AC)	480 V
Total nominal output	11 kW

Power Oil Pump	
Type	Screw pump
Power supply (AC)	480 V
Speed	3480 rpm
Rated power (motor)	17.25 kW
Nominal pressure	360 psi
Pump capacity	0.91 gal/s

Power Oil Filter	
Type	Twin filter
Max. throughflow	2008 US gal/h
Min. extraction fineness	10 micron

Power Oil Cooler	
Type	Tube cooler
Cooling medium	Lube oil
Coolant system absolute pressure:	approx. 87 psi
Power oil system absolute pressure:	approx. 360 psi

Cooling System - Air Cooling Recoolers	
Voltage (AC)	480 V
Output	88 kW
Speed	250 rpm
Diameter of fan	156"

Cooling System - Air Cooling Circulating Pump	
Type	Centrifugal
Voltage (AC)	480 V
Power	22 kW
Speed	3555 rpm

Fuel System: EV-Burners Design	
Min. fuel gauge pressure before the main shut-off valve (gas / diesel)	356/29 psig
Max. fuel gauge pressure before the main shut-off valve (gas / diesel)	420/116 psig
Min. fuel temperature before the main shut-off valve (gas / diesel)	20/41° F
Max. fuel temperature before the main shut-off valve (gas / diesel)	302/140° F
Max. permissible fuel oil viscosity before the main shut-off valve	6 cSt
Max. permissible fuel oil viscosity with fuel preheating	60 cSt
Fuel oil pressure after the fuel pump	1190 psi

Fuel oil pressure at the control valves, at full load, ISO	1160 psi

Fuel Filter	
Type	Self-cleaning filter
Material in filter elements	Steel
Fineness	35 μm

Fuel Meter in Measurement of Throughflow	
Type	Oval wheel rotameter
Accuracy	to within 0.2 %

Weights for Erection and Maintenance	
Erection: generator block	approx. 107.0 tons
Normal maintenance, hot gas path inspection: Combustor manhole cover	approx. 11.0 tons
Overhaul: gas turbine rotor	approx. 18.9 tons

3.3. ELECTRICAL SYSTEMS AND EQUIPMENT

Generator Circuit Breaker	
Type	Vacuum
Rated voltage	17.5 kV
Operating voltage	13.8 kV

Low Voltage DC Distribution Board

DC Distribution System 125 V Ungrounded	
Nominal (DC) voltage	125 V
Maximum (DC) voltage	140 V
Minimum (DC) voltage	105 V

DC Distribution Systems 24 V Two independent systems with common ground, negative pole grounded	
Nominal (DC) voltage	24 V
Maximum (DC) voltage	28.2 V
Minimum (DC) voltage	22.7 V

Battery Chargers and Inverter AC Input	
Nominal voltage 3 phase, at **Error! Reference source not found.** Hz ± 5%	480 V ± 10%,

DC Output DC Battery Charger 125 V	
Nominal voltage (DC)	125 V
Nominal current (DC)	60 A
Floating voltage (DC)	125.0 V
Equalizing voltage (DC)	131.6 V
DC ground fault	Supervision
Equalizing timer	0 ... 72 hrs

DC Output DC Battery Chargers 24 V	
Nominal voltage (DC)	24 V
Nominal current (DC)	60 A
Floating voltage (DC)	26.8 V
Equalizing voltage (DC)	28.2 V
Equalizing timer	0 ... 72 hrs

Inverter (UPS)	
Nominal input voltage (DC)	125 V
Nominal output voltage (AC)	230 V, 1 phase
Nominal output power	250 Ah

Enclosure	
Type of enclosure	NEMA

Batteries DC Battery 125 V	
Type	Lead - acid
Nominal voltage (DC)	125 V
Number of cells	62
Rating	250 Ah
Open discharge voltage	2.05 V/Cell
Final discharge voltage	1.75 V/Cell
Floating voltage	2.24 V/Cell
Equalizing voltage	2.33 V/Cell

Batteries DC Battery 24 V	
Type	Lead - acid
Nominal voltage (DC)	24 V
Number of cells	12
Rating	250 Ah
Open discharge voltage	2.05 V/Cell
Final discharge voltage	1.89 V/Cell
Floating voltage	2.24 V/Cell
Equalizing voltage	2.33 V/Cell

Generator Protection Generator Protection System Cubicle	
Auxiliary power supply (2 Circuits) DC	125 V
PT secondary voltage	120 V
CT secondary current	5 A
Degree of protection	NEMA 1

Generator Voltage Regulator Voltage Regulator	
System	Unitrol UNK 4807

Generator Voltage Regulator Auxiliary voltages	
Control voltage (DC)	125 V, 15 A
Signalization & synchronization (DC)	24 V, 15 A
Auxiliary power (AC)	230 V, 20 A
PT Secondary voltage	120 V
CT Secondary current	5 A
Degree of protection	NEMA 1

Generator Voltage Regulator Synchronization Equipment	
Auxiliary voltage (DC)	125 V
Control voltage (DC)	24 V
System	*Synchrotact/ Synchrocheck*
Synchronization across	Generator circuit breaker or HV main circuit breaker
Synchronization modes	Manual/Automatic/Test
PT secondary voltage	120 V

Generator Voltage Regulator Generator Output Metering	
Auxiliary voltage (DC)	125 V, 15 A
PT secondary voltage	120 V
CT secondary current	5 A
Transducer output (DC)	4 ... 20 mA
Accuracy class	0.5

Static Frequency Converter Input	
Voltage (sec. side of unit aux. transformer)	1.4 kV
Max. current	570 A
Rated power	1350 kVA
Voltage tolerance	± 10 %

Static Frequency Converter DC Intermediate Circuit	
DC current I*d*	700 A
Voltage U*d*	1.47 kV

Static Frequency Converter Output	
Rated power	1.0 MW
Max. voltage	1.25 kV
Max. current	600 A
Frequency	0 ... 40 Hz

Static Frequency Converter Starting Excitation	
Max. voltage (DC)	160 V
Max. current (DC)	130 A

Static Frequency Converter Values at Point of Connection	
Short circuit power	≥ 100 MVA
Voltage supply to converter	1.35 kV
Auxiliary power supply (AC) (excitation, auxiliaries)	480 V ± 10%
Control voltage (DC)	125 V

3.4. UNIT AUXILIARIES POWER CONSUMPTION

Auxiliary Loads	Starting Gas Fuel kW	Starting Liquid Fuel kW	Operation Gas Fuel kW	Operation Liquid Fuel kW	Standby
Gas turbine bearing support cooling	3.9	3.9	3.9	3.9	3.9
Main gas shut-off valve	0.4	-	-	-	-
Gas relief valve	0.2	-	0.2	-	-
Gas exhaust fan	0.2	-	0.2	-	-
Oil vapor exhaust fan	1.7	1.7	1.7	1.7	1.7
Auxiliary lube oil pump	86	86	-	-	86
Lube oil heating	-	-	-	-	33.7
Jacking oil pump	2.2	2.2	-	-	2.2
Power oil pump	17.25	17.25	17.25	17.25	-
Rotor barring device	-	-	-	-	0.3
Static frequency converter	1000	1000	-	-	-
Battery rectifiers	3	3	3	3	3
Electric control	10	10	10	10	10
Electric control enclosure	20	20	20	20	20
Main shut-off valve*	-	0.25	-	-	-
Fuel oil pump*	-	135	-	135	-
Sump pump*	-	1.2	-	1.2	-
Air coolers for lube oil and generator cooling water*	-	-	88	88	-
Water circulating pump*	-	-	22	22	-
Acoustical enclosure ventilation and lighting (outdoor)*	20	20	20	20	20
NOx water injection pump*	-	140	-	140	-

*) If applicable. Depends on Scope of Supply for unit offered.

Total Auxiliary Power Consumption

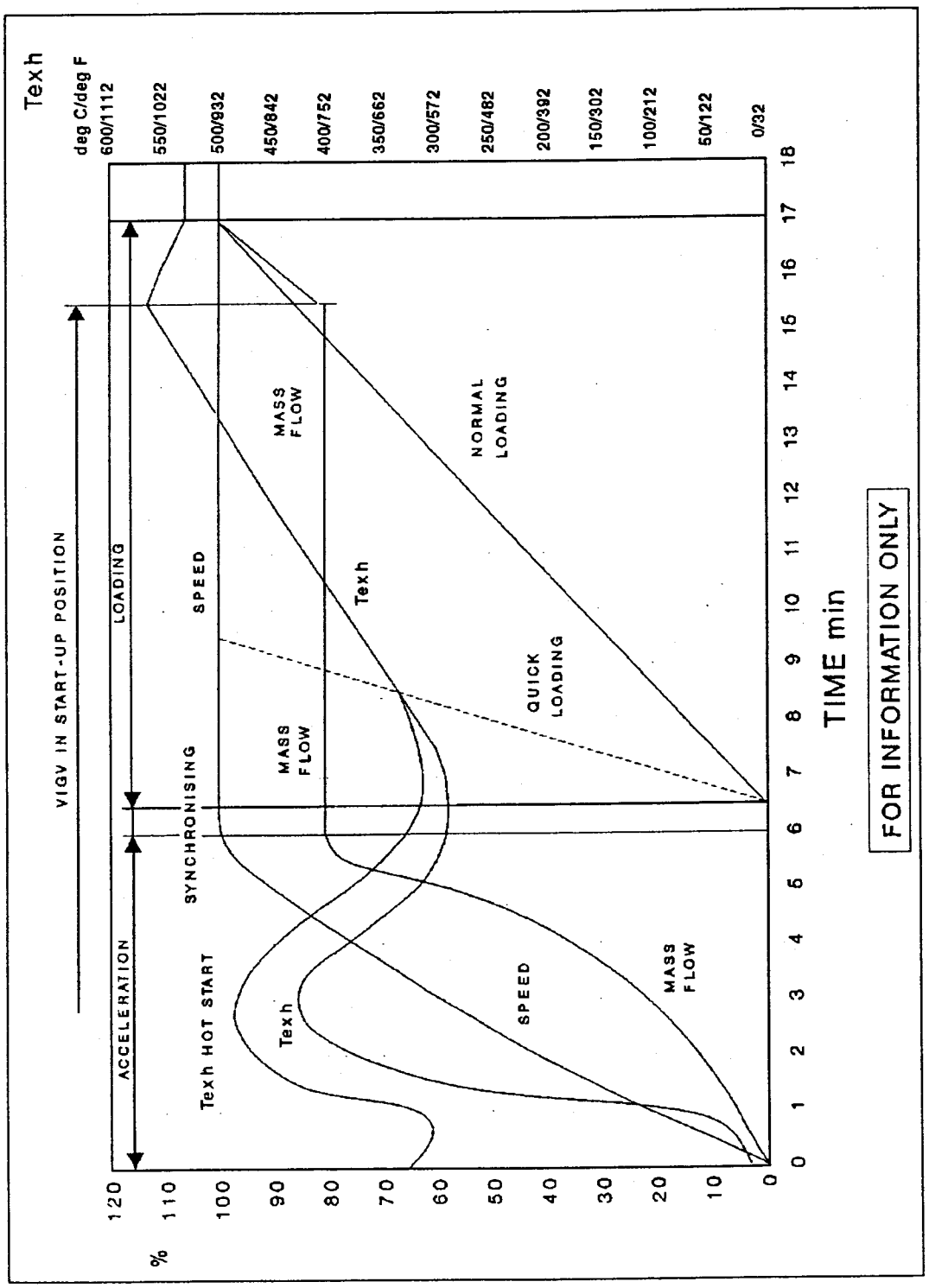
The total consumption of auxiliaries necessary for operation of a dual fuel unit amounts to approximately:

Air cooling Gas fuel kW	Air cooling Liquid fuel kW	Water cooling *) Gas fuel kW	Water cooling *) Liquid fuel kW	Standby kW
166	442	56	332	161

Consumption of air filter, fuel preheater, NOx water injection pump, fuel oil forwarding system, cooling water pumps, and acoustical enclosure ventilation and lighting not included (NOx water injection pump included in liquid fuel auxiliary consumption).

*) Based on treated cooling water.

3.5. GT 8C-EV START-UP OF GAS TURBINE

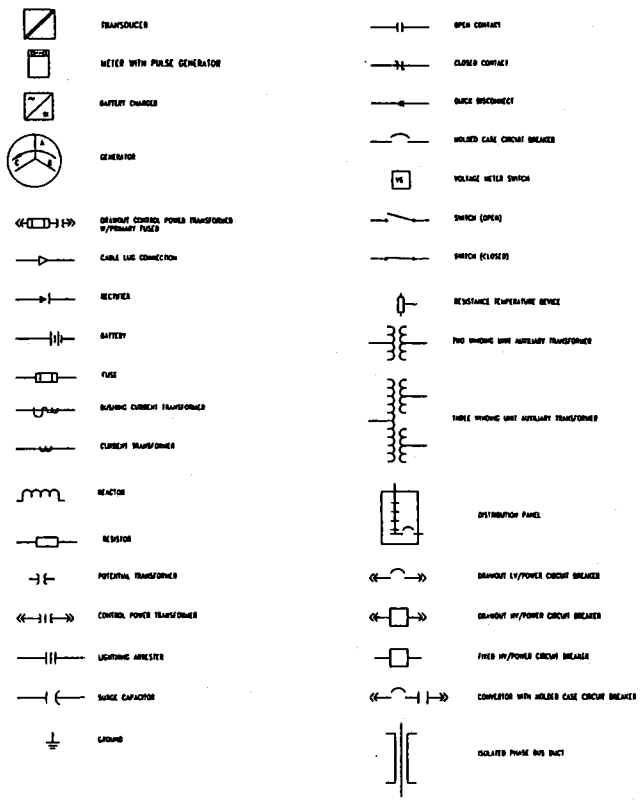


6.

SINGLE-LINE ELECTRICAL DIAGRAM

1.	SINGLE-LINE DIAGRAM STANDARD SYMBOL LIST	1AUE 100 082
2.	SINGLE-LINE DIAGRAM	1AUE 100 083

SYMBOLS



DEVICES IDENTIFICATION & DESCRIPTION

23	OIL TEMPERATURE SWITCH
24	VOLTS PER HERTZ RELAY
25	SYNCHRONIZING DEVICE
26	TRANSFORMER WINDING TEMP. SWITCH
27	UNDERVOLTAGE RELAY
32	REVERSE POWER RELAY
40	LOSS OF EXCITATION RELAY
41	FIELD CONTACTOR
42	MECHANICAL INTERLOCK DEVICE
46	NEGATIVE SEQUENCE RELAY
49	EQUIPMENT THERMAL RELAY
50/51	INSTANTANEOUS/TIME OVERCURRENT RELAY
51	TIME OVERCURRENT RELAY
51NT	TRANSFORMER NEUTRAL OVERCURRENT RELAY
51V	TIME OVERCURRENT UNDERVOLTAGE RELAY
52GT	GENERATOR TRANSFORMER CIRCUIT BREAKER
52S	STARTING UNIT SWITCHGEAR CIRCUIT BREAKER
52U	HIGH VOLTAGE CIRCUIT BREAKER
58	DIODE FAILURE RELAY
59	OVERVOLTAGE RELAY
59GN	GEN. STATOR GROUND PROTECTIVE RELAY
59NB	BUS GROUND PROTECTIVE RELAY
60	VOLTAGE BALANCE RELAY
63	TRANSFORMER SUDDEN PRESSURE RELAY
64F	ROTOR GROUND PROTECTIVE RELAY
67	GENERATOR DEAD MACHINE RELAY
71	TRANSFORMER OIL LEVEL SWITCH
79	RECLOSING DEVICE
81	FREQUENCY RELAY
87G	GEN. DIF. PROTECTIVE RELAY
87T	TRANSFORMER DIF. PROTECTIVE RELAY
87UAT	UNIT AUX. TRANS DIF. PROTECTIVE RELAY
BF	GENERATOR BREAKER FAILURE RELAY
VS	VOLTMETER SWITCH
AM	AMMETER SWITCH
MWH	MEGA WATT. HOUR
MVARH	MEGA VAR HOUR
KWH	KILO WATT. HOUR
MCC	MOTOR CONTROL CENTER
CPT	CONTROL POWER TRANSFORMER
UAT	UNIT AUXILIARY TRANSFORMER

LOCATION CODE

- • GENERATOR PROTECTION CUBICLE
- ○ GENERATOR BREAKER SWITCHGEAR
- △ 480V MOTOR CONTROL CENTER INSTRUMENT COMPARTMENT
- Ø VOLTAGE REGULATOR CUBICLE
- Ø EGATROL
- ▲ RELAYS THAT TRIP THE SWITCHYARD CIRCUIT BREAKER VIA GENERATOR PROTECTION CUBICLE
- ⊠ 480V MAIN DISCONNECT DEVICE UAT SECONDARY SWITCHGEAR
- □ 5KV MAIN DISCONNECT DEVICE UAT SECONDARY SWITCHGEAR

STANDARD

DRAWN: JB 10/26/93 CHECKED: GJP 10-26-93 STD. CHECKER: 10-26-93 APPROVED: 10/27/93

DERIVED FROM: 1AUE100028C1 SUPERSEDES: SUPERSEDED BY:

Revisions: Drawn / Revisions/Approved

Scale: 100082-1

Format: B

Language: 8C

Parts List: Yes / No

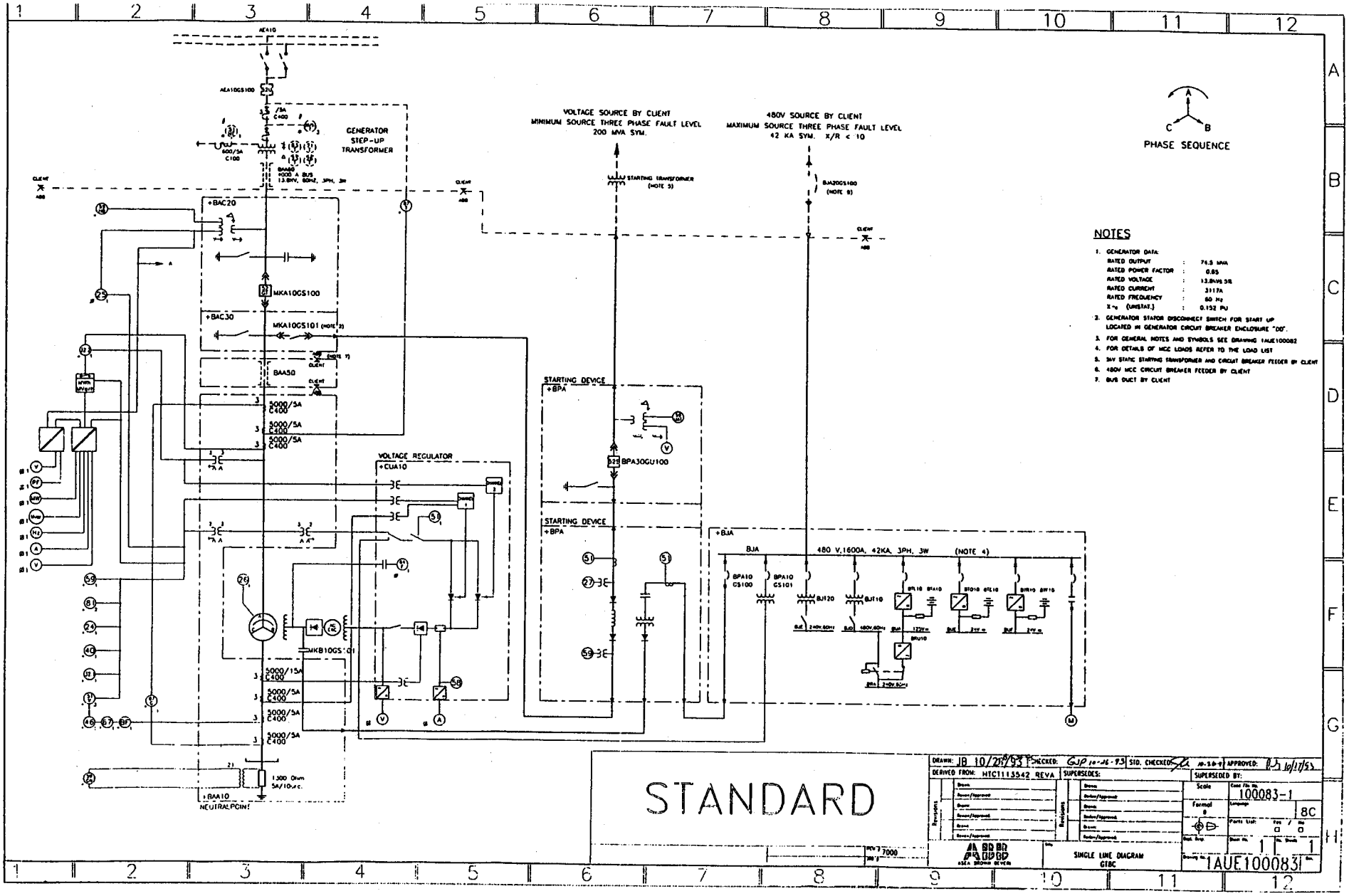
Dwg. No. 1 Sheet No. 1

Drawing No. 1AUE100082

ASEA BROWN BOVERI

SINGLE LINE DIAGRAM
STANDARD SYMBOL LIST
GT8C

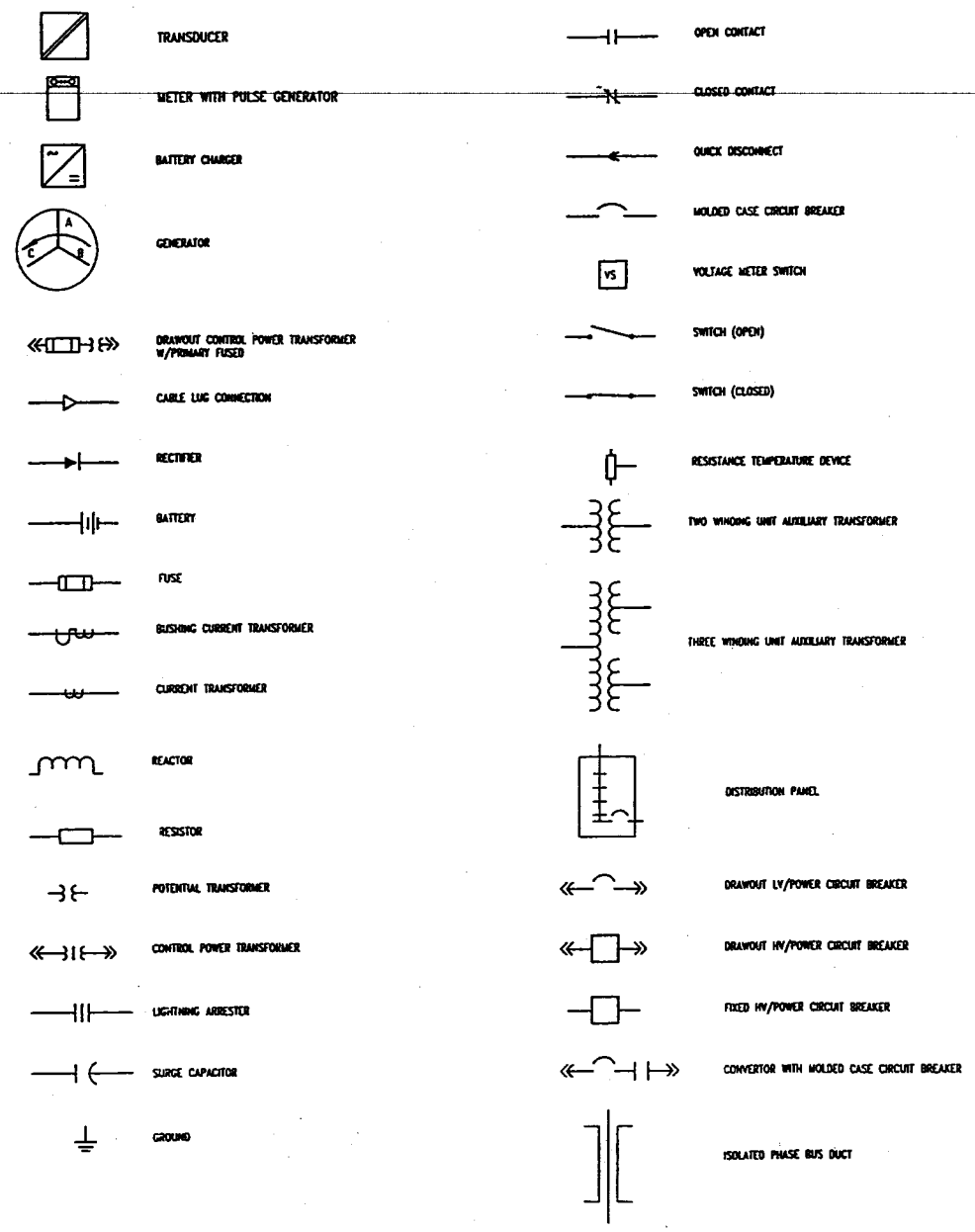
REV 7000



NOTES

1. GENERATOR DATA:
   - RATED OUTPUT : 76.5 MVA
   - RATED POWER FACTOR : 0.85
   - RATED VOLTAGE : 13.8kV±5%
   - RATED CURRENT : 3117A
   - RATED FREQUENCY : 60 Hz
   - X_{d} (UNSAT.) : 0.152 PU
2. GENERATOR STATOR DISCONNECT SWITCH FOR START UP LOCATED IN GENERATOR CIRCUIT BREAKER ENCLOSURE "DD".
3. FOR GENERAL NOTES AND SYMBOLS SEE DRAWING 1AUE100082
4. FOR DETAILS OF MCC LOADS REFER TO THE LOAD LIST
5. 34V STATIC STARTING TRANSFORMER AND CIRCUIT BREAKER FEEDER BY CLIENT
6. 480V MCC CIRCUIT BREAKER FEEDER BY CLIENT
7. BUS DUCT BY CLIENT

SYMBOLS



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VS	VOLTMETER SWITCH
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MCC	MOTOR CONTROL CENTER
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LOCATION CODE

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- ○ GENERATOR BREAKER SWITCHGEAR
- △ 480V MOTOR CONTROL CENTER INSTRUMENT COMPARTMENT
- Ø VOLTAGE REGULATOR CUBICLE
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- □ 5KV MAIN DISCONECT DEVICE UAT SECONDARY SWITCHGEAR

STANDARD

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DERIVED FROM: 1AUE100028C1 SUPERSEDES: SUPERSEDED BY:

Revisions: Drawn: Review/Approved: Drawn: Review/Approved: Drawn: Review/Approved:

Revisions: Drawn: Review/Approved: Drawn: Review/Approved: Drawn: Review/Approved:

Scale | Cadd File No. 100082-1

Format D | Language 8C

Parts List: Yes / No

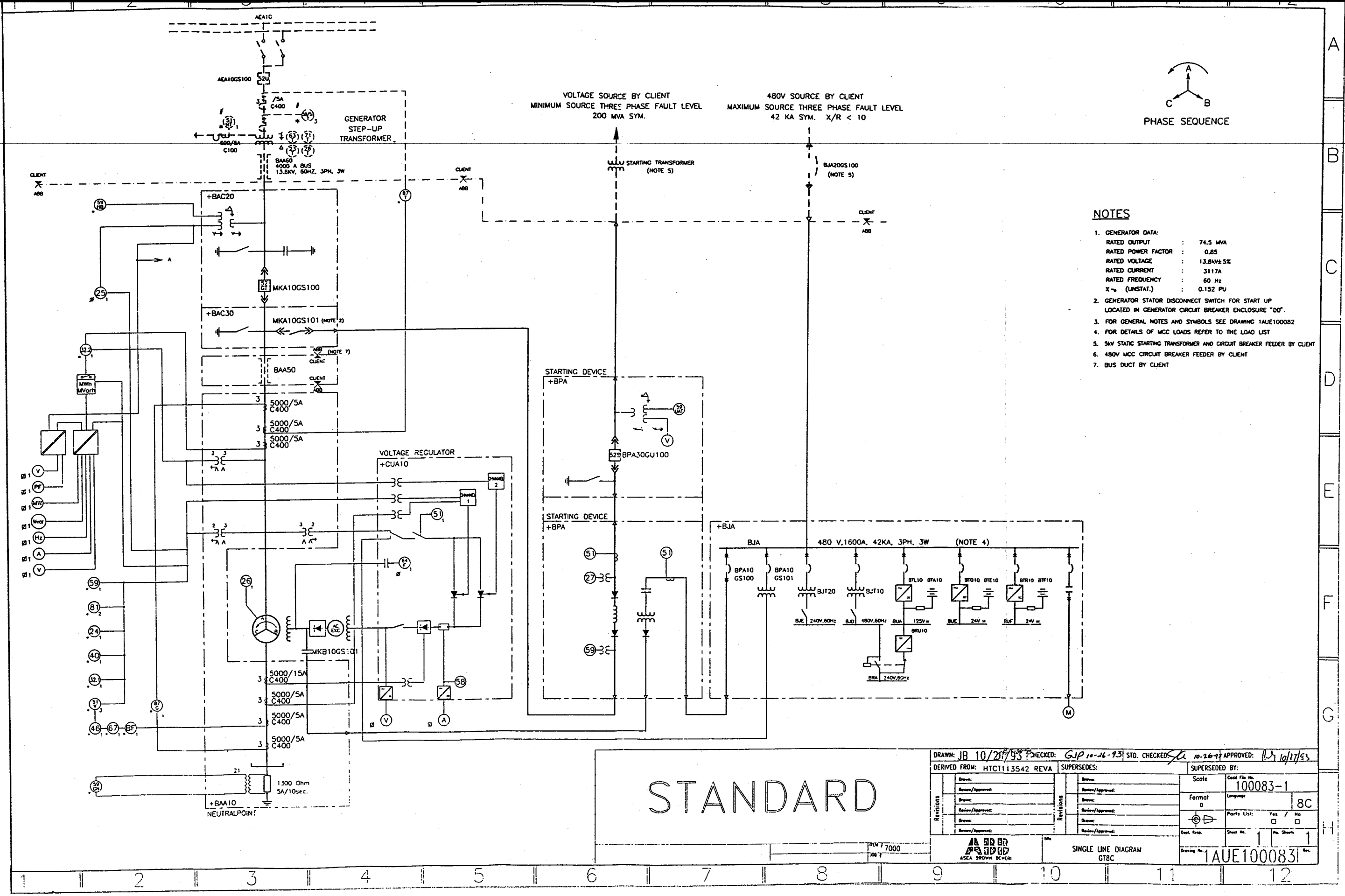
Dept. Resp. | Sheet No. 1 | No. Sheets 1

ASEA BROWN BOVERI

Title: SINGLE LINE DIAGRAM STANDARD SYMBOL LIST GT8C

Drawing No. 1AUE100082 Rev.

REV 7000 JOB



NOTES

1. GENERATOR DATA:

RATED OUTPUT	:	74.5 MVA
RATED POWER FACTOR	:	0.85
RATED VOLTAGE	:	13.8kV±5%
RATED CURRENT	:	3117A
RATED FREQUENCY	:	60 Hz
$X_{\sim 6}$ (UNSTAT.)	:	0.152 PU

2. GENERATOR STATOR DISCONNECT SWITCH FOR START UP LOCATED IN GENERATOR CIRCUIT BREAKER ENCLOSURE "DO".
3. FOR GENERAL NOTES AND SYMBOLS SEE DRAWING 1AUE100082
4. FOR DETAILS OF MCC LOADS REFER TO THE LOAD LIST
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6. 480V MCC CIRCUIT BREAKER FEEDER BY CLIENT
7. BUS DUCT BY CLIENT

STANDARD

DRAWN: JB 10/27/93 CHECKED: GJP 10-26-93 STD. CHECKED: 10-26-93 APPROVED: 10/27/93

DERIVED FROM: HTCT113542 REVA SUPERSEDES: SUPERSEDED BY:

Scale | Format D | Cadd File No. 100083-1 | Language 8C | Parts List: Yes / No | Sheet No. 1 | No. Sheets 1

ITEM 7000

ASEA BROWN BOVERI

SINGLE LINE DIAGRAM GT8C

Drawing No. 1AUE100083

7.

INSPECTION AND MAINTENANCE RECOMMENDATIONS

TABLE OF CONTENTS

7.1. RECOMMENDED INSPECTION SCHEDULE 2

7.1 RECOMMENDED INSPECTION SCHEDULE

INSPECTION INTERVAL	TYPE OF INSPECTION	TIME REQUIRED		PERSONNEL REQUIRED	
		Outage Time of Unit Days	Man-Hours	ABB	USER
6,000 HRS	A	2	80	1	3
12,000 HRS	B	3	210	3	6
18,000 HRS	A	2	80	1	3
24,000 HRS	C	13.5	2485	9	23

NOTES

1) Hours are defined as Equivalent Operating Hours (EOH)

   EOH = OH + ($S*W_1$)
   OH = Effective Operating Hours
   S = Number of Starts
   W_1 = Start Weighing Factor (one start = 20 hrs for normal start)

2) The calculation of EOH will vary with mode of operation and the type of fuel.

3) Frequency of inspection or calculation of EOH does not increase for water or steam injection operation.

4) The above information is provided for estimating purposes only.

TYPE "A" INSPECTION

THIS INSPECTION INCLUDES:

- Perform visual inspection just before shutdown and during coastdown and barring gear operation. Inspect for leaks, noises, high vibration and unusual conditions.
- Remove air inlet hatches and inspect filters, silencers, ducts, compressor bellmouth/bearing area, inlet guide vanes and compressor blading.
- Remove exhaust duct inspection hatches and inspect silencers, turning vanes, duct thermocouples and turbine blading.
- Remove combustor lid and inspect burner fuel nozzle, tiles, trunnions, inner housing, turbine blades and vanes.
- Boroscope turbine components.
- Check turbine controls, protection and monitoring systems.
- Perform additional services in accordance with the applicable ABB Service Manual.
- While some inspection tasks can be performed during cooldown, it is not recommended to boroscope the unit while on barring gear.

Type "A" Inspection is used for:

- Early identification of changes in the condition of parts in the hot gas path
- Initiation of rectification action as may be required
- Checking on operation settings important for availability
- Obtaining an overall impression of the condition of the gas turbine unit

The unit is not disassembled for this purpose. See Table 1, attached, for specific checks performed during the Type "A" inspection.

The minimum length of time in which this inspection can be completed is 48 hours from shutdown to startup.

TYPE "B" INSPECTION

THIS INTERMEDIATE INSPECTION INCLUDES:

Complete "A" inspection tasks, on more components. It includes checking of:

- The safety equipment of the gas turbine set
- Hydraulic and electronic closed-loop control systems
- The open-loop controls and annunciation systems

Perform additional services in accordance with the ABB Service Manual.

See attached Table 1 for specific checks performed during Type "B" inspection.

The minimum length of time in which this inspection can be completed is 64 hours. If you plan to complete some "B" tasks during the "A" inspection you can complete this inspection in 48 hours also.

TYPE "C" INSPECTION

THIS MAJOR INSPECTION INCLUDES:

- Complete Type "A" and "B" inspection tasks.
- Remove acoustic enclosure and turbine combustor.
- Remove turbine casing and rotor.
- Visual inspection of turbine blading and vanes. This scope assumes no defects are found and only normal cleanup is performed.
- Remove generator end shield and perform visual inspections.

See attached Table 1 for specific checks performed during the Type "C" inspection.

This scope assumes a gas fired unit undergoing it's first "C" inspection. Subsequent inspections will require that some turbine blading and vanes will either be replaced or repaired at a qualified facility.

This inspection will typically be completed in 13 to 15 days.

Attachment 2

Table 1: Short Description of Inspection Program

Inspection Type		A		B		C
Object / system		specific checks		specific checks in addition to A		specific checks in addition to B
Gas turbine						Open turbine
air inlet system	x		x		x	
bleed valve system					x	
compressor	x	inlet	x	inlet	x	blading
burner	x	flame	x	burner/nozzle	x	burner/nozzle
ignition system	x	function	x	igniter	x	igniter
combustion chamber	x		x		x	combustion
turbine	x	hot section	x	hot section	x	blading/vane
exhaust gas system	x		x	boroscope	x	carrier cooling channels
Generator + accessories						
Generator			x		x	
generator aux. system					x	
excitation			x		x	
starting device					x	
Bearing						
gearing/aux. gearing					x	
bearing, thrust bearing					x	
Auxiliary systems						
lube oil	x		x	coolers	x	checking of pumps
cooling water	x	leakage	x	system	x	motors
cooling/sealing air	x		x	function check	x	coolers
AC/DC supply					x	
batteries					x	
Fuel systems						
fuel oil	x		x		x	checking
fuel gas	x	leakage	x	system check	x	pumps
additive	x		x		x	motors, actuators
Controls						
temperature control	x		x		x	
other turbine controls			x		x	
Protection/Monitoring						
temperature protection	x		x			
overspeed protection	x		x			
flame monitor	x		x			
turbine protection					x	
generator protection					x	
indicator, meas. instr.					x	
recorder					x	
Fire protection systems			x		x	
Fire fighting systems					x	

Appendix F:
Conceptual Design Equipment List

The conceptual design equipment list is presented here for the conceptual design presented in Section 8 for the land based design at Kayar.

ABB GT8C Combustion Turbine Based Combined Cycle
MECHANICAL EQUIPMENT LIST

ITEM	EQUIPMENT SCOPE	QTY	CAPACITY BASIS/DATA	DESCRIPTION
0101.00	STEAM TURBINE AND GENERATOR	1	**THROTTLE:**157,320 #/hr at 862 psia and 923F **LOW PRESSURE INPUT:** 36,000 #/hr at 79.6 psia and 512F **EXHAUST:** 193,320 #/hr at 1.5 psia **OUTPUT:** 23,168 kw **GENERATOR:** ____ MVA @ 11 kV, 50 Hz, 0.85 pf.	Condensing turbine with one controlled admission port. TEWAC generator.
0102.00	COMBUSTION TURBINE AND GENERATOR	1	**OUTPUT:** 47,374 kw @ 77 F (28 C) **HEAT RATE:** 10,370 Btu/kWh (LHV) **NO_x EMISSIONS:** 25 ppmVd @ 15% O_2 **GENERATOR:** __ MVA @ 22 kV, 50 Hz, 0.80 pf.	ABB GT8C Dual Fuel, Dry low Nox: Water injection for Nox control when firing distillate oil. Open air-cooled generator
0905.01	NITROGEN STORAGE SYSTEM	1		
1203.01	HRSG BLOWDOWN VESSELS	2	**CAPACITY:** 750 gal. (2.84 m³) (Nom.) **DESIGN PRESS:** 400 psig (2.86 MPa)	Design vertical, carbon steel vessel per ASME Section VIII and National Board requirements
1203.02	HRSG BLOWOFF TANKS	2	**CAPACITY:** 750 gal. (2.84 m³) (Nom.) **DESIGN PRESS:** 50 psig (446 kPa)	Design vertical, carbon steel vessel per ASME Section VIII and National Board requirements
1204.00	NATURAL GAS COMPRESSOR	NR	**CAPACITY:** **DISCHARGE PRESSURE:**	Unit required only if natural gas supply pressure is below minimum for CTG.
1204.01	NATURAL GAS KNOCKOUT VESSEL	1	**DESIGN FLOW:** 25,000 lb/hr **DESIGN PRESS:** 700 psig	Design vertical, carbon steel vessel per ASME Section VIII with stainless steel mesh pad, removal to 1µ.
1301.01	BLOWOFF COOLER	1 - 100%		Shell-and-tube type
1302.00	STEAM SURFACE CONDENSER	1	**DUTY:** 185 x 10^6 Btu/h **TEMPERATURE RISE:** 15 F **WATER FLOW:** 27,000 gpm **WATER T:** 70 F	Two-pass, divided waterbox, shell-and-tube unit. Carbon steel shell, stainless steel tubes. Condenser shall be designed to deaerate condensate.
	CONDENSER AIR REMOVAL SYSTEM	2 - 100%	**FLOW:** 20 scfm **TDH:** 14 psi	Skid-mounted liquid ring vacuum pumps with accessories, instrumentation and controls. Holding and Hogging service
1304.01	AUXILIARY COOLING WATER HEAT EXCHANGERS	2 - 100%	**DUTY:** 20 x 10^6 Btu/hr **ACW FLOW:** 2500 gpm **ACW T:** 70F **CCW FLOW:** 2500 gpm **CCW T:** 95	Plate-and-frame type
1305.00	DESUPERHEATERS	1 Lot		
1311.00	SAMPLE COOLERS	1 Lot		
1313.00	CTG AIR INLET COOLING COIL	NR	**AIR FLOW:** Not Required **INLET:** **OUTLET:**	
1501.00	BOILER FEEDWATER PUMPS	3 - 50%	**FLOW:** 250 gpm **TDH:** 3000 ft	Centrifugal, ring-section, multi-stage, motor-driven
1502.03	CLOSED COOLING WATER PUMPS	2 - 100%	**FLOW:** 2500 gpm **TDH:** 170 ft	Centrifugal, Horizontally split , single-stage, double suction, cast iron constr.
1502.04	ARU CIRCULATION PUMPS	NR	**FLOW:** Not Required **TDH:**	Centrifugal, Horizontally split , single-stage, double suction, cast iron constr.
1502.05	CHILLED WATER DISTRIBUTION PUMPS	NR	**FLOW:** Not Required **TDH:**	Centrifugal, Horizontally split , single-stage, double suction, cast iron constr.

1502.06	DISTILLATE OIL TRUCK UNLOADING PUMP	2 - 100%	Unload 10,000 gal truck in 30 min. **FLOW:** 333 gpm (75.7 m³/h, 17.8 kg/s) **TDH:** 170 ft (51.8 m, 517 kPa)	Centrifugal, horizontal, motor- driven
1502.07	DISTILLATE OIL FORWARDING PUMP	2 - 100%	**FLOW:** 100 gpm (22.7 m³/h, 5.5 kg/s) **TDH:** 170 ft (51.8 m, 517 kPa)	Centrifugal, horizontal, motor- driven
1503.00	CONDENSATE PUMPS	3 - 50%	**FLOW:** 250 gpm **TDH:** 230 ft	Centrifugal, vertical turbine can-type, motor-driven
1507.00	MAIN CIRCULATING WATER PUMPS	2 - 50 %	Two pumps required for normal condenser duty **FLOW:** 14,000 gpm **TDH:** 30 ft	Multi-stage vertical turbine diffuser type pump. Cast Iron construction.
1507.01	TRAVELING WATER SCREENS	2-50%		Face velocity limited to 0.75 fps.
1508.00	FIRE WATER PUMPS	2 - 100% plus 1 jockey	**FLOW:** 2500 gpm **TDH:** 150 psi	Horizontal centrifugal-type One Diesel, one motor, one jockey
1510.00	WASTEWATER SUMP PUMPS	1 Lot	**FLOW:** 200 gpm **TDH:** 100 ft	Vertical, centrifugal, motor-driven, single-stage
1608.00	HEAT RECOVERY STEAM GENERATOR	1	**HP:** 157,320 lb/hr @ 887 psig, 928 F **LP:** 36,000 lb/hr @ 85 psig & 525 F	Natural circulation boiler with two pressures of steam generation Complete with main stack, bypass stack and associated dampers. Provided with duct burners for natural gas.
1701.00	COOLING TOWER	NR		
1801.01	NATURAL GAS BOOSTER COMPRESSOR	NR	**FLOW:** Not Required **SUCTION:** **DISCHARGE:**	Reciprocating compressor, non-API
1801.02	AIR COMPRESSOR SKID	2 - 100%	**FLOW:** 200 scfm **SUCTION:** 0 psig **DISCHARGE:** 125 psig	Rotary screw air compressor, two desiccant dryers, and one receiver mounted on a common skid with control panel.
1803.01	ABSORPTION REFRIGERATION UNITS	NR	**CAPACITY:** Not Required	
1921.01	RAW WATER/FIRE WATER STORAGE TANK	1	Allows for 2 hour storage capacity Fire Water and for 24 hours normal water supply using natural gas fuel. **CAPACITY:** 400,000 gal	Field-erected carbon steel per AWWA standards. 49.3 ft x 29 ft H (15 m D x 8 m H)
1921.02	DISTILLATE OIL STORAGE TANK	1	Three Days storage capacity total **CAPACITY:** 250,000 gal Total	Carbon steel tank per API 650 with secondary containment.
1922.01	KNOCKOUT VESSEL DRAINS TANK	1	**CAPACITY**: 400 gal **DESIGN PRESS:** 15 psig	Carbon steel, above ground.
1922.02	GAS TURBINE DRAINS TANKS	1	**CAPACITY:** 530 gal	Horizontal, cylindrical, carbon steel tanks
1922.03	GAS TURBINE WATER WASH TANK	1	**CAPACITY:** 2640 gal	Horizontal, cylindrical, carbon steel tanks
1922.04	COOLING WATER HEAD TANK	1	**CAPACITY:** 500 gal **DESIGN PRESS** 15 psig	Carbon steel, above ground.
1931.01	DEMINERALIZED WATER STORAGE TANK	1	**CAPACITY:** 150,000 gal	Field-erected, epoxy-lined carbon steel 82 ft x 25.3 ft H (25 m x 7.7 m H)
1931.02	NEUTRALIZATION WASTE STORAGE TANK	1	**CAPACITY:** 150,000 gal.	Field-erected, epoxy-lined carbon steel, suitable for a buffer storage of 24 hours.
	WASTEWATER TREATMENT SYSTEM	1	**CAPACITY:** 100 gpm	System consists of calrifier, sludge dewatering system two stages of pH adjustment and finishing sand filter.
	STORM WATER POND		**SIZE:** Assume pond size to be 0.3 acres, dredged to 6 feet deep.	Lined Collection Pond for storm runoff from contaminated areas of site. Suitable for 25 year storm (24 hours): assumed to be 6" total rainfall.
2212.00	OIL/WATER SEPARATOR	2	**CAPACITY:** 3000 gal	Horizontal, cylindrical, carbon steel, static separator located in a below-grade concrete vault

2306.01	RAW WATER FEED PUMPS	2 - 100%	**CAPACITY:** 500 GPM @ 200 Ft. TDH	Sized to fill Raw Water/Fire Water Tank in 12 hours with plant not running and 24 hours with plant running.
2306.02	PLANT SERVICE WATER PUMPS	2 - 100%	**CAPACITY:** 250 GPM @ 250 Ft. TDH	Sized to deliver water sufficient for operation with distillate oil firing in CTG while supporting normal plant operation.
2307.01	WATER TREATMENT SYSTEM - DEMINERALIZER SYSTEM	2 - 100%	**CAPACITY:** Peak capacity is 100 gpm, sufficient to allow for operation of combustion turbine on distillate oil fuel, maximum cycle blowdown and 20 gpm of "catch-up".	Consists of pretreatment system (sand filter and/or carbon filter), cation, anion, and mixed bed chemical demineralizers, acid and caustic feed system for "on-site" regeneration and all required transfer and forwarding pumps. System will be arranged in two trains to allow for "on-line regeneration.
2307.01 A	SULPHURIC ACID STORAGE TANK	1	**CAPACITY:** Estimate 6000 Gallons capacity	Sufficient capacity to accept one truck load (4000 gal) while still having sufficient operating reserve.
2307.01 B	CAUSTIC SODA STORAGE TANK	1	**CAPACITY:** Estimate 6000 Gallons capacity	Sufficient capacity to accept one truck load (4000 gal) while still having sufficient operating reserve.
2307.04	LUBE OIL PURIFICATION SYSTEM	N/R	**CAPACITY:** _____ gpm (_____ m^3/h)	
2307.05	WATER SUPPLY PREFILTER	1 - 100%	**CAPACITY:** 500 GPM	Sized to support flow through raw water feed pumps
2307.05 A	PREFILTER UNDERFLOW PUMPS	2 - 100%	**CAPACITY:** 10 GPM	Sized to remove underflow from filter and deliver it to waste treatment system
2310.01	STEAM CYCLE CHEMICAL FEED SYSTEM	1	Phosphate (corrosion inhibitor) to drums Hydrazine (oxygen scavenger) to FW Neutralizing amine to condensate	Packaged unit mounted on a common skid with metering pumps, SS tamks and agitators.
2310.02	CIRCULATING WATER CHEMICAL FEED SYSTEM	1	As required	
4190.01	CIRCULATING WATER BUTTERFLY VALVES	9		
4190..0 2	CIRCULATING WATER EXPANSION JOINTS	9		
4190.03	SAFETY AND RELIEF VALVES	1 Lot	As required by the piping system.	
	FIRE PROTECTION SYSTEM	1 Lot	Per NFPA Standards	Foam system for fuel oil storage tanks. Deluge system for transformers and ST lube oil systems. Hose racks, portable extinguishers, etc.
	HVAC EQUIPMENT	1 Lot	Per ASHRAE Standards Design WB Temp = 72 F Design DB Temp = 90 F	Fans, louvers, air-conditioning units, Packaged Roof-top DX units, etc as required by Code and detailed designs.
	STANDARD AND SPECIALTY VALVES	1 Lot	As required by the piping system	
	PIPING	1 Lot	As required by the piping system	
	PIPE HANGERS	1 Lot		Prefabricated pipe supports, hangers, restraints, supplemental steel, rods, washers, nuts, clevises, platen, saddles, guides, anchors, supports, and accessories for the installation of piping.
	THERMAL INSULATION AND LAGGING	1 Lot		The insulation systems are designed and rated in accordance with the service application and location.
	LUBRICANTS, CHEMICALS, AND MISCELLANEOUS	1 Lot		Lubricants, chemicals, greases, etc. for initial start-up.
	SPECIALTY ITEMS	1 Lot		Strainers, temporary strainers, traps, expansion joints, expansion couplings, spray nozzles, and orifices as required for the piping systems.

ELECTRICAL & CONTROLS EQUIPMENT LIST

ITEM	EQUIPMENT SCOPE	QTY	CAPACITY BASIS/DATA	DESCRIPTION
211.01	STG GENERATOR CIRCUIT BREAKER	1	15 kV, 6000 A, 63 Ka	Metal clad vacuum type power circuit breaker.
211.02	CTG GENERATOR CIRCUIT BREAKER	1	24 kV, 2000 A	Metal clad vacuum type power circuit breaker.
212.01	4.16 kV STATION SERVICE SWITCHGEAR	1	6.6 kV, 3000 A, 250 MVA	Indoor, metalclad switchgear w/vacuum circuit breakers and motor controllers
212.03	480 V STATION SERVICE SUBSTATION	1	480 V, 3000 A Switchgear with 2000/2500 kVA AA/FA transformer 6.6-480 V, 2-Winding	Indoor, dry-type,double-ended switchgear and air breakers, close coupled to 6.6/0.48 kV transformer.
213.02	UNIT AUXILIARY TRANSFORMER	1	12/16 MVA OA/FA, 65 C Rise 13.8 kV - 4.16 kV, 2-Winding	Outdoor, oil-filled, delta-wye resistance grounding. Off-load tap changing.
216.31	25 kV BUS DUCT	1 Lot	25 kV, 7000 A, 125 kV Impulse Withstand 100 kA Short-circuit	CTG Generator Leads. Aluminum bus with aluminum enclosure, isolated phase bus duct.
216.31	15 kV BUS DUCT	1 Lot	15 kV, 6000 A, 110 kV Impulse Withstand 100 kA Short Circuit	STG Generator Leads. Aluminum bus with aluminum enclosure, isolated phase bus duct.
216.31	15 kV Bus Duct	1 Lot	15 kV, 1200 A, 110 kV Impuse Withstand 100 kA Short Circuit	Aux Transformer Leads. Aluminum bus with aluminum enclosure, isolated phase bus duct.
216.32	6.6 kV BUS DUCT	1 Lot	5 kV, 2000 A, 40 kA Short-circuit	Copper bus with steel enclosure, non-segregated phase bus duct.
221.01	HV CIRCUIT BREAKERS	3	225 kV, 2000 A, 1050 kV BIL, 40 kA Short-Circuit	
221.02	HV 1PH DISCONNECT SWITCHES	6	225 kV, 2000 A, 40 kA Short-circuit	outdoor, insulated, horizontal center break type, 3 pole - single throw, motor operated.
221.03	HV LIGHTNING ARRESTORS	12	276 kV	Zinc-oxide, station type - 276kV RMS, 224kV MCOV.
221.04	HV COUPLING CAPACITOR VOLTAGE TRANSFORMER	13	225 kV Line-to-Line primary with Dual secondary @ 115/69 V	Single phase, oil immersed.
221.06	HV CURRENT TRANSFORMER	9	Multi-ratio, 1200-5 A	Oil immersed, post type.
225.00	REVENUE METERING PANEL	1		Solid state microprocessor type meters to record energy in and out, voltage, current and frequency
226.01	SWITCHYARD PROTECTION PANEL	1		Protective relay panels for two transmission line, switchyard and transformer protection.
226.02	SWITCHYARD SCADA SYSTEM	1		RTU with necessary input transducers and remote transmitting capability to monitor station operations.
226.03	SWITCHYARD CONTROL PANEL	1		Control panel for breaker contol, synchronizing, monitoring and alarms.
227.01	CTG MAIN STEP-UP TRANSFORMER	1	150/200/250 MVA OA/FA/FA, 65 C Rise 225/22 kV, 2-Winding, BIL: HV - 1050 kV LV - 150 kV	Outdoor, oil-filled with fan cooling and , LV Delta- HV wye solid grounding, Off-load tap changing.
227.02	STG MAIN STEP-UP TRANSFORMER	1	75/100/125 MVA OA/FA/FA, 65 C Rise 225/13.8 kV, 2-Winding, BIL: HV - 1050 kV LV - 110 kV	
230.00	TRANSMISSION LINE	1	**VOLTAGE:** 225 kV **CAPACITY:** **LENGTH:**	

242.00	480 V MOTOR CONTROL CENTERS (MCC)	5	480 V, 800 A, 50 kA	Indoor Type, NEMA Class 1B
251.00	UNINTERRUPTIBLE POWER SUPPLY SYSTEMS	1	20 kVA, Indoor inverter, static switch, accessories 20 kVA, sine wave output 225A, 30 Circuit Distribution Panel	120 V AC, 1-phase. Each with inverter, static switch, manual bypass switch Regulated bypass transformer Distribution panel, 1 PH, 2-Wire With Stand-alone Battery
252.01	125 V STATION DC SYSTEMS	1	125 V DC Battery, 1800 Amp-Hours with, 1200 A Main panel & 200A Subdistribution Panel.	Gel-cell indoor-type battery with rack Self-cooled battery charger. Indoor Distribution Panel Indoor Distribution Panel
252.03	125 V SWITCHYARD DC SYSTEMS	1	125 V DC Battery, 250 Amp-Hours 400 A, 125 V DC Distribution Panel, ____ A Main Bus Subdistribution Panel, ____ A Main Bus	Gel-cell indoor-type battery with rack Self-cooled battery charger. Indoor Distribution Panel Indoor Distribution Panel
271.00	TELECOMMUNICATIONS SYSTEM	1	4 Trunk Lines, 40 extensions	PABX System with main switchboard.
272.00	PLANT PAGING AND SECURITY SYSTEM	1		
273.00	FIRE ALARM AND DETECTION SYSTEM	1 Lot	Per NFPA 70, 72 and 72E	Fire Control Panel, Detectors and Pullboxes
274.00	CATHODIC PROTECTION SYSTEM	1 Lot		As required for tank bottoms, underground piping and condenser
275.00	LIGHTNING PROTECTION SYSTEM	1 Lot		Design per NFPA 78
	LOW VOLTAGE AC PANELBOARD	1 Lot	460 V, 3-phase, 4-wire	Indoor, surface mount
	ELECTRICAL CABLE	1 Lot	5 kV and 600 V, as required	Copper conductor, EPR insulation
	ELECTRICAL CONDUIT AND TRAY	1 Lot	As required	Steel cable tray. RGS or PVC conduit
	STATION GROUNDING MATERIAL	1 Lot	As required	#4/0 AWG bare copper cable with 10 ft. Ground Rods
	RELAY TESTING AND SETTING	1 Lot		
301.00	DISTRIBUTED CONTROL SYSTEM	1	As required Digital I/O As required Analog I/O	Process computer with one (1) operator s station. Color CRT with keyboard.
302.00	SAMPLING AND ANALYSIS PANEL	N/R	Manual grab samples	
303.00	CONTINUOUS EMISSIONS MONITORING SYSTEM	1		Extractive sampling and monitoring for NO_X, CO, and O_2
304.00	ANALYZERS	1 Lot	As required	Conductivity, CEM analyzers, gas calorimeter, etc.
305.00	CONTROL VALVES	1 Lot	As required	
4170.00	FIELD INSTRUMENTATION	1 Lot	Pressure guages, switches and transmitter; Temperature elements and transmitters Level guages, switches and transmitters Flow elements, switches and transmitters P guages, switches and tranmitters	As required for control and monitoring of power station

CIVIL/STRUCTURAL

ITEM	EQUIPMENT SCOPE	QTY	CAPACITY BASIS/DATA	DESCRIPTION
	CLEARING AND GRUBBING	1 Lot		
	EXCAVATION AND BACKFILL	1 Lot		
	CONCRETE	1 Lot		
	EMBEDMENTS	1 Lot		
	FOUNDATIONS	1 Lot		
	STRUCTURAL STEEL	1 Lot		
	MASONRY	1 Lot		
	MISCELLANEOUS STEEL AND METAL WORK	1 Lot		
1001.01	TURBINE BUILDING CRANE	1	CAPACITY = 50 tons	
1002.00	HOISTS	1 Lot		
	BUILDINGS	As required		Steam Turbine Building Fuel Oil Pump House Cooling Water Pump House Fire Pump House Administration Building Maintenance Shops

Appendix G:
Select Site Background Documents

Select documents providing information relevant to site consideration, particularly the Kayar site, are presented here.

January 26, 1998

Dear Mr. Rubow

Please find attached a report on Kayar. The information indicated allows us to comment that Kayar is a good possibility for the 90 MW plant.

Please accept our salutations

Signed Mr. Fall
Director of Innovation, Planning and Equipment

Mission Report

Introduction: On Friday, January 9, 1998 a team of DIPE went to Kayar for the purpose of giving an opinion on that site and that was done for the feasibility study of the 90 MW plant. We are providing here the information collected.

Accessibility: The site of Kayar is situated about 70 kilometers from Dakar. It is accessible by road and is about 21 kilometers from the railroad

Terrain: The terrain is flat.

Transmission Line: The 90 kV line is approximately 11 kilometers from the site on the road.

Wind: The wind direction that day was north-south. For emission reporting, the south of Kayar, would be more appropriate.

Cooling: The depth of the sea must be determined. At high tide, the sea covers two-thirds of the beach which is surrounded by "filaos." (sic - meaning unknown).

Gas: The new Petrosen gas wells located at GADIAGA are 10 kilometer (in a straight line) from Kayar (per Petrosen).

Ground: A study of the ground must be done.

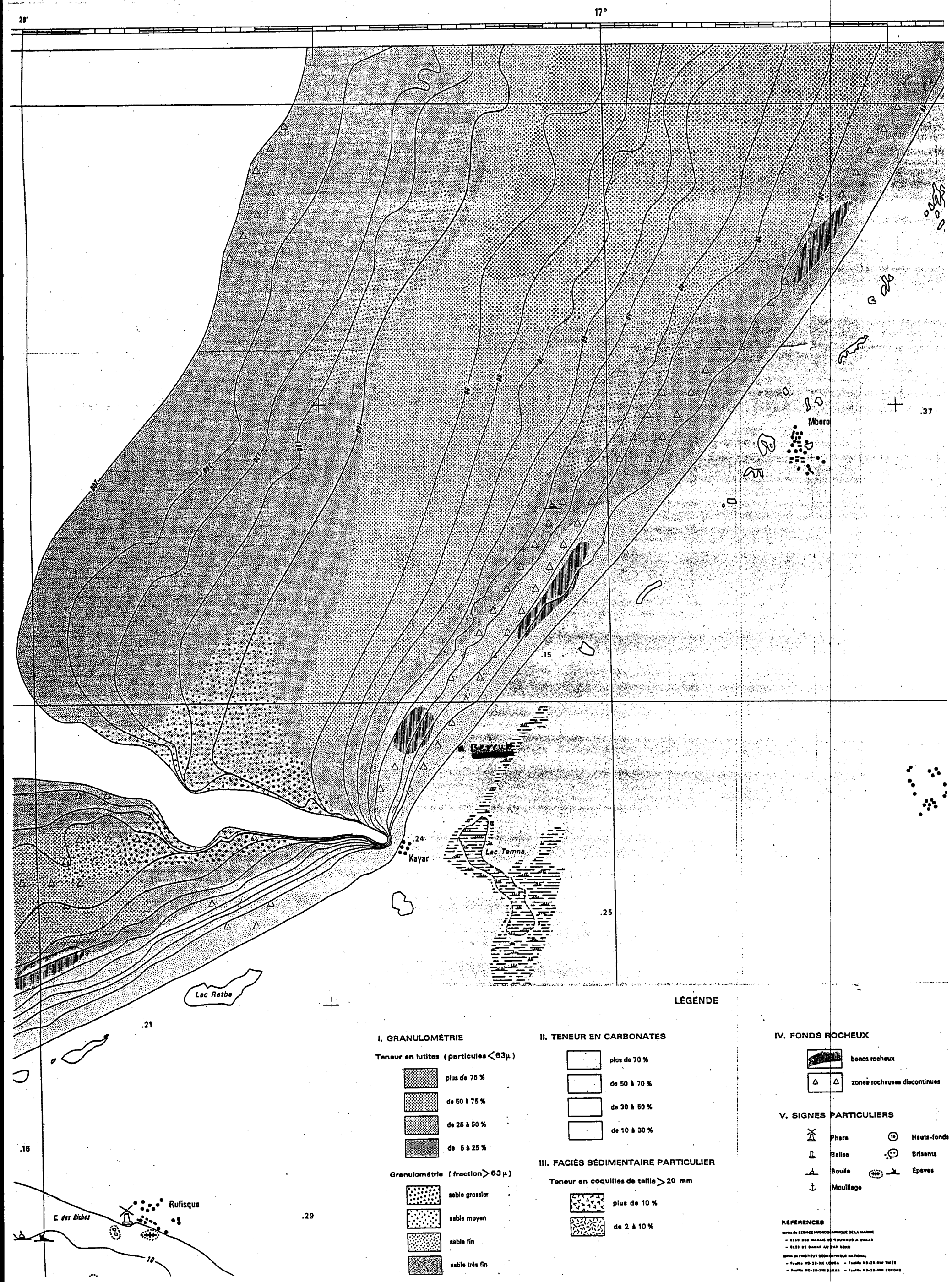
Taking into account the preceding information, Kayar seems to be a good site and it would be appropriate to make a more detailed evaluation of the parameters indicated above.

Signed by the Missionnaries
Mamadou C. NDIANE"
Diombass DIAW

CARTE SEDIMENTOLOGIQUE DU PLATEAU CONTINENTAL SENEGAMBIEN

ECHELLE : 1/200 000

PAR FRANÇOIS DOMAIN (ORSTOM/CRODT, 1977)



GEOTECHNICAL MAP OF DAKAR

SOIL APTITUDE ON DIFFERENT TYPES OF FOUNDATIONS

Soil aptitude on foundations has been mapped out on a purely quantitative way, but has been defined from quantitative data extracted from files of Building and Public Work Laboratory of Dakar, summed up in the recapitulative tables of geotechnic characteristics of different soil formations, and from the indications furnished by geologic map and substratum morphology maps.

The mapped out aptitude of soils on foundations has been essentially based on the quality of superficial soils and on their density, on the nature and the substratum depth, in order to define the more or less favorable zones for constructions on superficial foundations and required zones for profound foundations.

I. SUPERFICIAL FOUNDATIONS

1) Favorable zones for implantation of all types of constructions, even heavy, on superficial foundations

a) - basalts :
These zones corresponds to bevelling the basalt habe or overlapping by an altered superficial fringe where the density does not pass but exceptionally three meters.
In all cases, it is necessary to carefully clean the deteriorating horizon where the swollen properties are particularly noxious and to sit the foundations on the basalt habe which authorizes the amount of elevated work, at times limited by the resistance concrete (45 kg/cm2 on average)

b) - laterite cuirass :
When its density is sufficient (between 4 meters), and when it homogeneity can be assured, the laterite cuirass (and at one degree less, the gravel from of laterite), can constitute a good foundation level.
It is used like that in the table-land zone and of superficial foundations solutions (general strike off in most cases) has been adopted for certain big tenements in the Center of the capital (Building Administrative, National Theatre...).

Always, for very heavy tenements, the foundation on general strike-off should be difficult to retain, taking into account the nature of the lands under vacancy.

The residual constraints imposed on profound soil, risks to affect in particular the horizon of clay alteration, compressing and subject to swelling, which is generally found under the laterite cuirass.

For this reason, the central table-land zone is considered, in the aptitude map on foundation soils, like a favorable zone at the construction of heavy building, but with reserve.

At this, and that this zone is particularly complex by the rapide lateral changes observed in nature of clay formations, these added lateral changes are complicated by the effects of the tectonic.

2 - Favorable zones at implantation of average important constructions

a) The sand dunes

These sand constitute a good soil foundation for the constructions of average importance, hamely in enriched clay levels.

The amount of work allowed varies from 1 to 3 bars and the settling are generally immediate and of weak vastness.

The presence of a hydrostatic level situated at weak depth (2 to 4 meters on average) may sometimes drive to certain disorders if a minimum of elementary precautions are not respected.

b) Clay sand and super-basaltic clay sand

The amount of work applicable to these soils are in function to their susceptibility and weakness, and overall to swelling, and could be varied at 1 to 6 bars as per the case.

We must therefore consider that these terrain are particularly more fitted to support the constructions of average importance printed on soil of sufficient constraints to counteract the effects of swelling.

3 - Zones favorable only for the implantation of light construction

These zones are distinguished essentially by their topography.

It matters, in effect, in every case, the more or less accented slope, turns toward the ocean and situated all along the coast between the beach of Rebeuss on the west corniche and the Point E of Dakar on the east.

The nature of terrains, flows, favors the superficial alteration phenomenon. An analogic situation, but more favorable nevertheless because of the best holding of grounds (volcanic breaches consolidated and relatively analtered) is found in the Ouakam bay. So in these zones, the major problems are linked to the sloped stability and only light constructions are likely to be superficially built.

For heavier constructions, we should necessarily have recourse at the foundation depth.

II - FOUNDATIONS DEPTH

The problems of foundations' depth are always delicate and it is impossible to study here the in detail the solutions of depth foundations could be retained on the whole of the closer island of Dakar.

Very schematically, two types of principal zones have been defined in function to the depth of rocky sound substratum.

1) Zones in which the substratum is found at a depth inferior to 20 meters

In these zones, the solution of drilled or marshed turbular pile (when the collection is essentially sandy or clay and sand) used in the foreground could be planned, on condition however, that the work load allowed by the supporting ground justifies deep foundations.

2) Zones in which the substratum is found at a superior depth of 20 meters

In these zones, the collection is essentially sandy or clay with sand. The solution of marshed turbular pile working essentially in the general rubbing movement could be retained.

The same restriction as in the former case, concerning the compatibility between the allowed workload and the depth of the foundation, should be appropriated, taking into account the turbular pile dimension and of their anchorage plugs.

ETUDE DE FAISABILITE RELATIVE A UNE CENTRALE ELECTRIQUE DE 90 MW AU SENEGAL

DOCUMENT N° 4

DONNEES HYDROGEOLOGIQUES

COMPRENANT : 1 TEXTE DE 20 PAGES
6 FIGURES
1 EXTRAIT DE CARTE

MB. THIAM
CONSULTANT
54 04 63 - DAKAR

SOURCE : BRGM N° 38 AGE 013

I - IDENTIFICATION ET RESSOURCES DES DIFFERENTS AQUIFERES

La zone de l'étude est constituée par les formations sédimentaires suivantes dessinées sur la carte géologique de la Fig. 1 avec, de la base au sommet :

- Les grès calcaires et sables plus ou moins argileux du Maestrichtien, épais de 200 à 400 m et perméables.

- Les calcaires plus ou moins karstifiés du Paléocène, très perméables, d'une centaine de mètres d'épaisseur.

- Les marnes de l'Eocène, peu perméables, dont l'épaisseur varie de 100 à plus de 200 m.

- L'ensemble du Lutétien, représenté de manière discontinue ; on retiendra essentiellement les calcaires du Lutétien moyen et supérieur qui se développent à l'Est et au Nord-Est du secteur étudié, ils sont karstifiés et donc perméables.

- Les formations sableuses, perméables du Quaternaire , dont l'épaisseur varie d'une dizaine de mètres à plus de 60 m.

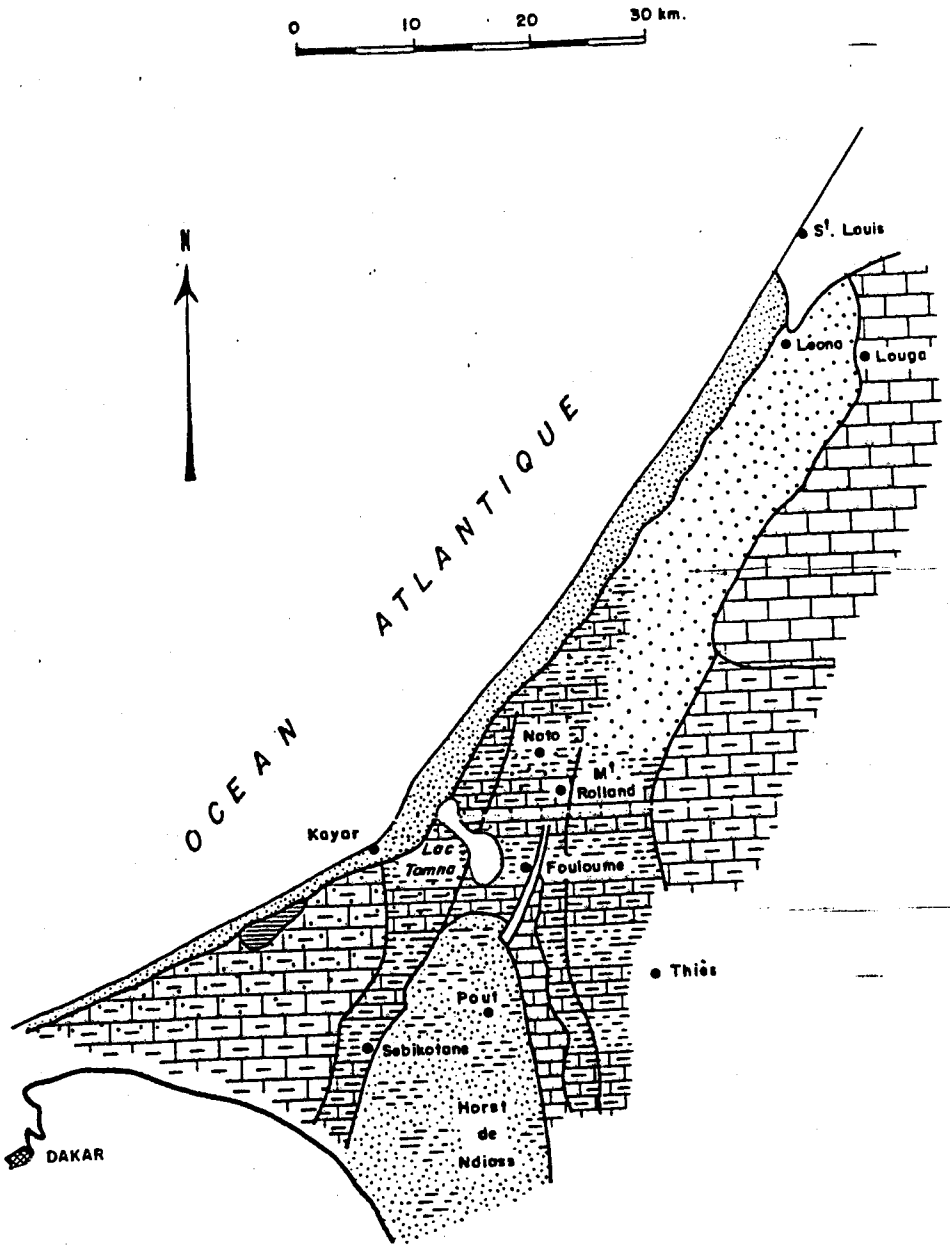
Bien que ces dernières formations soient les seules à intéresser la zone des Niayes, nous considérerons brièvement, à la demande des partenaires chargés des problèmes miniers, les autres formations aquifères présentés dans le soubassement de notre zone d'études.

I.1 FORMATION AQUIFERE DU MAESTRICHTIEN

Le Maestrichtien présente des variations de faciès et d'épaisseur. Ainsi, dans la zone comprise entre la route Thiès-Louga et la côte, il passe de sables grossiers vers le Nord (Léona) à un faciès plus argileux et plus fin vers le Sud, tout en augmentant d'épaisseur (de 200 m au Nord à 500 m et plus au Sud).

Fig. 1

CARTE GEOLOGIQUE SCHEMATIQUE DU LITTORAL NORD DU SENEGAL



LEGENDE

- Dunes récentes (vives et semi-fixées)
- Dunes rouges
- Eocène moyen:
  - Lutétien moyen et supérieur calcaire
  - Lutétien inférieur marnes et marno-calcaires
- Eocène inférieur - Ypresien argiles, marnes, marno-calcaires
- Paléocène calcaire
- Moestrichtien sables ± argileux

Le Maestrichtien est alimenté au Sud par la nappe phréatique du horst de N'Diass et indirectement par un effet de drainage du Paléocène sous-jacent.

Un abaissement important et général de la nappe est perceptible dans la région de Taïba et Tivaouane. Dans le secteur Mt Rolland-Noto, la baisse annuelle est de 0,40 m.

Les possibilités de cette formation aquifère sont donc très limitées, dans le secteur Lac Tamna-Taïba en raison de cet abaissement très accentué, abaissement qui pourrait entraîner une remontée du sel à partir du Campanien sous-jacent.

La nappe du Maestrichtien est saumâtre au Nord (13 g/l à Léona) mais cette minéralisation diminue rapidement vers le Sud. Ainsi, à une dizaine de km au Sud de Louga, l'eau douce commence à être décelable par sondages électriques, et au-delà d'une ligne Kébémer-~~Lompoul, elle se perçoit~~ assez nettement.

1.2 FORMATION AQUIFERE DU PALEOCENE

Le Paléocène forme un ensemble épais d'une centaine de mètres composé de calcaires karstifiés et de marnes. Ces calcaires, très perméables, peuvent servir de drain à la nappe Maestrichtienne sous-jacente.

Dans la partie sud, le Paléocène se trouve dans le prolongement de l'anticlinal de N'Diass, faillé selon des directions N.S délimitant de ce fait trois compartiments avec d'Ouest en Est, celui de Sébikotane puis celui de Pout-Noto et enfin le plateau de Thiès. De plus, son épaisseur varie: alors qu'il n'existe pas sous le lac Tamna, il atteint 100 m à Noto puis 200 m à l'aplomb de la côte.

D'un point de vue hydrochimique, la nappe du Paléocène est de bonne qualité dans la partie Nord (résidu sec de 0,3 à 0,5 g/l) et de qualité médiocre au Sud (0,7 g/l à 3 g/l). Ses possibilités sont très faibles du fait d'une exploitation intensive, au moins dans la partie sud.

1.3 FORMATION AQUIFERE DU LUTETIEN

Les calcaires lutétiens, bien développés à l'Est d'une ligne Thiès-Louga, ne se rencontrent dans notre secteur que ~~sous une forme plus ou moins~~ démantelée.

Les aquifères des sables quaternaires et des calcaires lutétiens constituent un même système hydraulique.

En effet, aucune barrière de perméabilité vraiment marquée et continue ne sépare les deux formations.

1.4 FORMATION AQUIFERE DES SABLES QUATERNAIRES ET DU CONTINENTAL TERMINAL

Il est difficile de différencier, de manière certaine, les deux étapes. Ils sont en effet tous deux constitués de dépôts argilo-sableux, d'origine essentiellement éolienne.

La nappe phréatique existe partout dans ces sables éoliens et affleure dans les dépressions interdunaires dénommées "niayes".

Cette nappe est plus couramment dénommée "nappe des sables".

II - LA "NAPPE DES SABLES" DE DAKAR A ST LOUIS

2.1 PRESENTATION GENERALE

En bordure de la côte, entre Dakar et St Louis, la formation des sables quaternaires couvre une superficie de 2 300 km2 et apparaît comme un ensemble assez homogène.

Elle s'étire sur plus de 150 km de long et 10 à 15 km de large.

Son épaisseur est variable, résultant du comblement d'un ancien réseau hydrographique, de moins en moins marqué en allant du Sud vers le Nord.

Le fond des niayes a une cote voisine de + 5 à + 7 m et la surface des eaux souterraines, de salinité excédant rarement 1 g/l, se trouve à une profondeur généralement inférieure à 1 m. Certaines niayes, comme celle de M'Boro sont en communication avec la mer.

2.2 HISTORIQUE DES ETUDES

La région des niayes a fait l'objet de nombreuses études essentiellement dans un but d'aménagement hydro-agricole.

Une première étude a été effectuée pour l'alimentation en eau des exploitations de phosphates de Taïba.

(R. Degallier, 1956, hydrogéologie de la région de Taïba).

La même année, P. MICHEL, pour le compte de la mission d'aménagement du Sénégal, apportait une première synthèse des connaissances générales sur la région.

Toujours la même année, R. Degallier étendait à la totalité de la feuille de Louga (1/200 000) les résultats des diverses connaissances géologiques et hydrogéologiques récoltées lors de l'inventaire des points d'eau et de la recherche des phosphates. En même temps, était effectuée une étude géophysique par sondages électriques pour le Service de la Géologie et Prospection Minière mettant en évidence l'absence d'invasions salées le long de la côte, sauf au Nord et présentant une hypothèse sur la structure géologique du substratum des sables aquifères.

En 1962, J. Putallaz effectuait une synthèse de la documentation antérieure, complétée par des travaux géomorphologiques et géologiques sur le terrain et sur photos aériennes.

De 1962 à 1965, la S.C.E.T. entreprenait une étude hydrogéologique de la zone des niayes et concentrait sur une niaye "type" un réseau de mesures hydrologiques afin d'effectuer un essai de bilan "apports-exutoires" et de comprendre ainsi le fonctionnement du système hydraulique des niayes.

En 1968, ces mesures étaient analysées dans un rapport sur la mise en valeur par irrigation d'une surface de 120 ha, complétées par un essai de reconstitution par analogie électrique des écoulements dans le système Niaye-Dune côtière-Océan.

En 1974, dans le cadre d'un projet O.M.S. destiné à évaluer les ressources en eau souterraine dans un rayon de 250 km autour de Dakar, un réseau piézométrique était implanté et le BRGM effectuait un modèle mathématique de la nappe des sables quaternaires entre Dakar et St Louis.

En 1978, Y. Noël (BRGM) dans son étude hydrogéologique des calcaires lutétiens entre Bambey et Louga, étudiait la bordure orientale de la nappe des sables en contact avec les calcaires lutétiens qui se développent à l'Est de la route Thiès-St Louis.

Enfin, on citera les études plus ponctuelles, de S. Solages et D. Thiery, effectuées en 1980, dans le secteur de Darou-Ndoye pour l'irrigation d'une plantation d'agrumes, qui amenèrent à l'exécution de quatre forages d'exploitation.

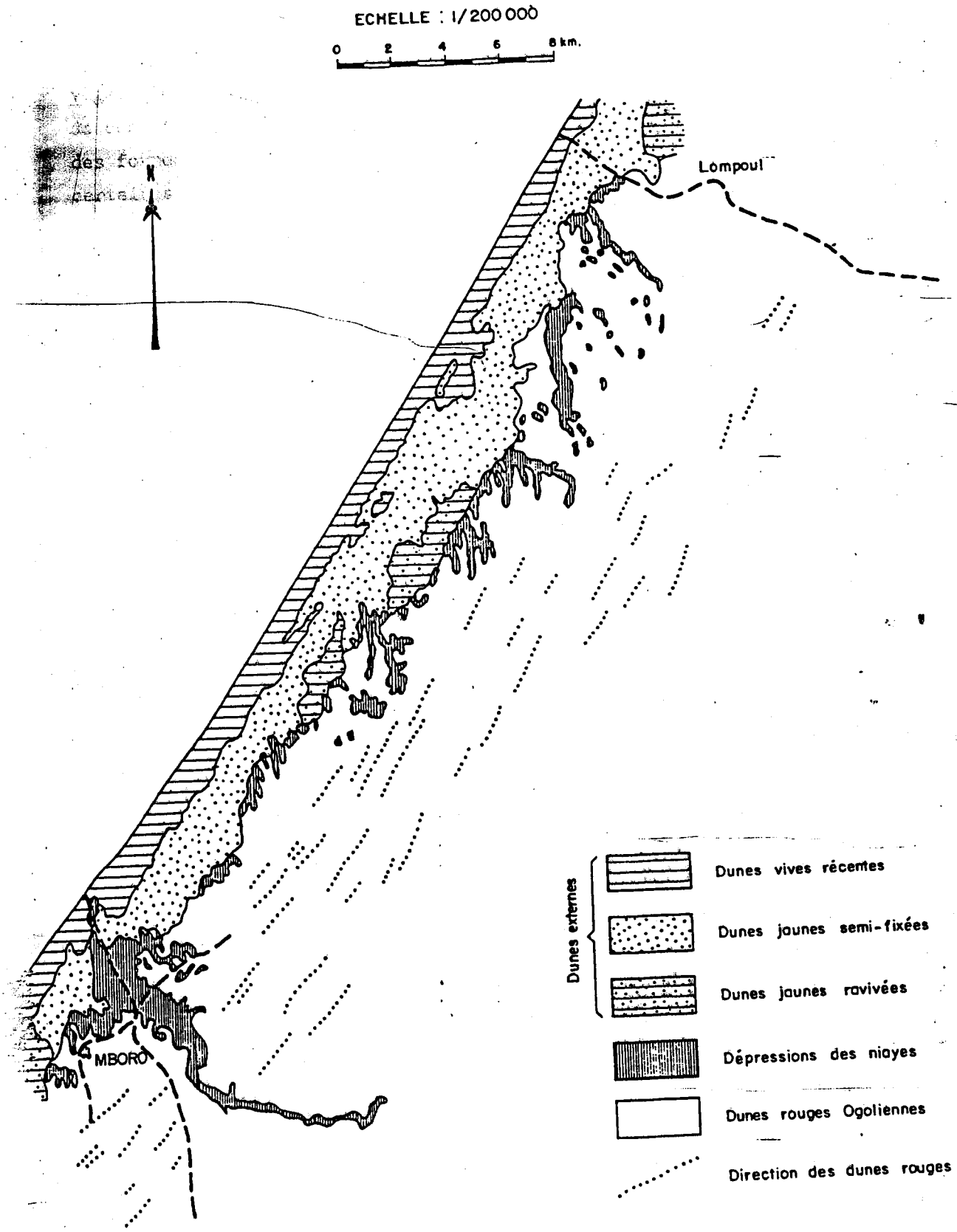
2.3 *GEOMORPHOLOGIE ET PALEOGEOGRAPHIE*

D'un point de vue géomorphologique, cette formation aquifère est caractérisée par deux ensembles de sables dunaires distincts. D'Est en Ouest on distingue des dunes internes et des dunes externes comme indiqué sur la Figure 2.

On notera l'absence de réseau hydrographique actuel. Par contre, on retrouve dans les dépressions interdunaires des témoins d'un ancien réseau (les niayes) plus ou moins oblitéré par l'avancée des dunes externes.

Fig. 2

GEOMORPHOLOGIE DE LA ZONE DES NIAYES



2.3.1. - *Les dunes internes ou dunes rouges*

Elles ont un modelé peu prononcé et sont actuellement fixées par la végétation. D'âge Ogolien, elles ont une direction NE.SW. Les changements de conditions climatiques ont provoqué un effacement et un émoussé général des formes et des directions, bien que le relief reste parfois assez vigoureux, certaines dunes atteignant encore une hauteur de 20 mètres.

A une dizaine de kms de la côte, l'altitude moyenne au-dessus du niveau de la mer varie entre 20 et 50 mètres. Vers l'Ouest, en bordure des dunes jeunes et au Nord, en bordure du delta du Sénégal, cette altitude diminue. Elle varie entre 1 et 10 mètres dans les points bas où affleure la nappe. Au Nord, où les dunes empiètent sur le delta, les bas-fonds sont voisins du niveau de la mer et au Sud, dans le lac Tamna, ils ont même des cotes négatives.

A la limite occidentale des dunes rouges se trouvent les niayes. Celles-ci ont tendance à être plus ou moins empâtées par le sable des dunes externes.

2.3.2. - *Les dunes externes*

Les dunes jaunes, au relief émoussé, de direction NW-SE sont en partie fixées par la végétation. Parfois, elles ont tendance à être remaniées et reprises en dunes vives, notamment le long de leur bordure avec les niayes qu'elles ensevelissent alors peu à peu. Leur altitude dépasse généralement 10 m et peut atteindre une quarantaine de mètres. Leur avancée est importante sur les niayes qui se trouvent à leurs pieds, sous le vent dominant, c'est-à-dire les alizés du secteur Nord. On enregistre ainsi parfois une avancée d'une centaine de mètres en 30 ans. On distingue trois types de formations:

- les dunes jaunes ravivées : les plus à l'intérieur des terres donc les plus anciennes

- les dunes jaunes semi-fixées : situées à l'Ouest des précédentes donc plus jeunes

- les dunes vives récentes ou dunes blanches : en formation actuellement le long du rivage.

Remarque: Certaines dunes rouges sont également ravivées, peut-être consécutivement à la sécheresse. Par exemple, le forage K7 de la S.C.E.T. implanté en juin 62 en amont de la niaye de N'Denn, au Sud de M'Boro, a été retrouvé enfoui sous 20 à 30 cm de sable, ce qui, compte tenu de la hauteur probable du tubage, représente un recouvrement de 60 à 70 cm en 20 ans.

2.3.3. - *Origine et évolution de la zone littorale actuelle*

Pour comprendre l'origine et l'évolution des niayes, il est nécessaire de suivre l'évolution climatique du pays depuis la formation des dunes rouges jusqu'à la fin de la transgression Flandrienne. L'échelle géologique du Tableau 1 explicite les différentes phases paléogéographiques.

A l'Ogolien, dans une période de régression marine, un climat extrêmement aride provoque l'extension du désert sur la basse Mauritanie, le Nord et l'Ouest du Sénégal.

Des dunes hautes et régulières, de direction NE-SW se forment et recouvrent un ancien relief, modelé au cours du Tertiaire supérieur et du Quaternaire ancien. La mer est en régression.

Puis règne un climat plus humide et se produit une transgression du niveau marin. C'est le début de l'Ouljien. Les sables se rubéfient et le ruissellement forme un réseau hydrographique de direction perpendiculaire à la mer.

Vers la fin de l'Ouljien, un climat aride s'installe avec une régression marine au cours du Préflandrien.

La sécheresse s'accentuant, des dunes de direction NW-SE se forment et comblent la base du réseau hydrographique. A l'intérieur, certaines dunes rouges se ravivent, provoquant la naissance de nouvelles dunes et l'ensablement partiel du réseau hydrographique.

Au début du Flandrien, le climat redevient plus humide, une légère rubéfaction se produit et la mer transgresse une nouvelle fois. Le maximum de la transgression est marqué par des dépôts de plages marins à 1 m-1,5 m au-dessus du niveau actuel de la mer.

Tableau 1 - SEQUENCE LITHOSTRATIGRAPHIQUE LOCALE DU QUATERNAIRE

LITHOLOGIE	VARIATIONS LATERALES POSSIBLES	EPAISSEUR	ETAGE	AGI B.P.
Sable fin dunaire blanc (dunes vives externes)	sable éolien gris	99 mètres	SUB ACTUEL (oscillations)	
				2 000
Sable dunaire fin jaune (dunes jaunes externes)	cordons littoraux emboités liés à la transgression flandrienne	0 à 15 m	FLANDRIEN (transgression)	
Vase argileuse noire à paletuviers		0 à 2 m		
				5 000
Sable argileux gris consolidé à fins débris de coquilles	sables argileux gris consolidés sans coquilles	0 à 8 m	NOUAKCHOTTIEN (transgression)	
Sable argileux gris consolidé à grosses coquilles (Arca Senilis)		0 à 4 m		
				8 000
Sables humifers Tourbe ligneuse	faciès transgressifs sous climat humide	?	TCHADIEN OULDJIEN	
				18 000
Sable dunaire fin orange à rouge (dunes rouges internes)		0 à 50 m	OGOLIEN (régression)	
				20 000
Coquilles cimentées en lumachelles et grès de plages	sables à coquilles marines		INCHIRIEN (transgression puis régression)	
				30 000
Argile sableuse jaunâtre à silex et blocs marno-calcaire	lacune stratigraphique		CONTINENTAL TERMINAL	

B.P. = Before present : échelle des temps en milliers d'années à partir de l'année 1957 (datation C 14)

Puis, le climat devenant plus sec, jusqu'à nos jours, les dunes vives se développent, les dunes jaunes se ravivent et le processus de comblement du réseau hydrographique se poursuit, laissant des témoins que l'on nomme aujourd'hui les niayes.

Au sud de Léona les niayes sont allongées NW-SE, et sont donc plus ou moins perpendiculaires aux directions des dunes rouges et à la côte.

Par contre, au nord de Léona, les niayes sont de direction parallèle à la côte et font partie du système du delta du fleuve Sénégal, comblé par les dunes dans sa partie sud.

2.4 GEOLOGIE DES FORMATIONS

Les Niayes constituent des dépressions localisées le long et en arrière du cordon dunaire entre St Louis et Dakar sur près de 150 km. Elles sont associées à des zones de lacs ou d'anciens lacs très souvent assèchées ou en cours d'assèchement.

2.4.1. - Les formations quaternaires

Les sédiments tourbeux ou sableux rencontrés dans ces niayes sont encadrés à la base et vers l'intérieur par les sables fauves ogoliens, au sommet et vers la côte actuelle par les sables à Arca et les dunes subactuelles ou actuelles.

Les conditions de gisement de la tourbe dépendent à la fois de la forme de la niaye et du réseau hydrographique mis en place postérieurement au dépôt de la tourbe et qui a pu raviver ou éroder une partie de ces sédiments organiques. Les gisement sont en outre barrés très souvent par des sables dunaires coquilliers propres. Les dépôts tourbeux se présentent en général auréolés dans un système de méandres de la niaye, associés à des sables humifères, à des sables tourbeux, plus rarement à des argiles. Certaines zones basses, en eau actuellement, ont continué à fonctionner comme tourbières et la tourbe à carex s'y accumule au-dessus des dépôts organiques anciens.

En dessus de ces formations récentes, on rencontre de haut en bas schématiquement les terrains suivants:

- sable fin dunaire : il peut constituer un aquifère intéressant dans la frange littorale

- sable fin plus ou moins argileux avec niveaux latéritiques et couches de grès limonitiques

- sable fin à moyen éolien ; il constitue le principal aquifère sableux de cette zone

- sable argileux à argile sableux, bariolé, marin plus ou moins fortement éolisé, incluant parfois des formations éocènes remaniées

La série sablo-argileuse présente une épaisseur de l'ordre de 60 m.

2.4.2. - *Le substratum tertiaire*

Nature

A l'Ouest d'une ligne Pire Goureye - Ndande-Guéoul, les sables quaternaires reposent sur les marnes lutétiennes. A l'Est de cette même ligne, le bed-rock rencontré est le calcaire du Lutétien supérieur. Au Sud, à l'approche de Kayar et du lac Tamna où existe une tectonique plus compliquée caractérisée par un important jeu de failles, on peut voir apparaître comme substratum des sables, des calcaires Paléocène, les marnes et calcaires marneux de l'Ypresien ou du Lutétien inférieur et les formations argileuses et latéritiques du Mio-Pliocène.

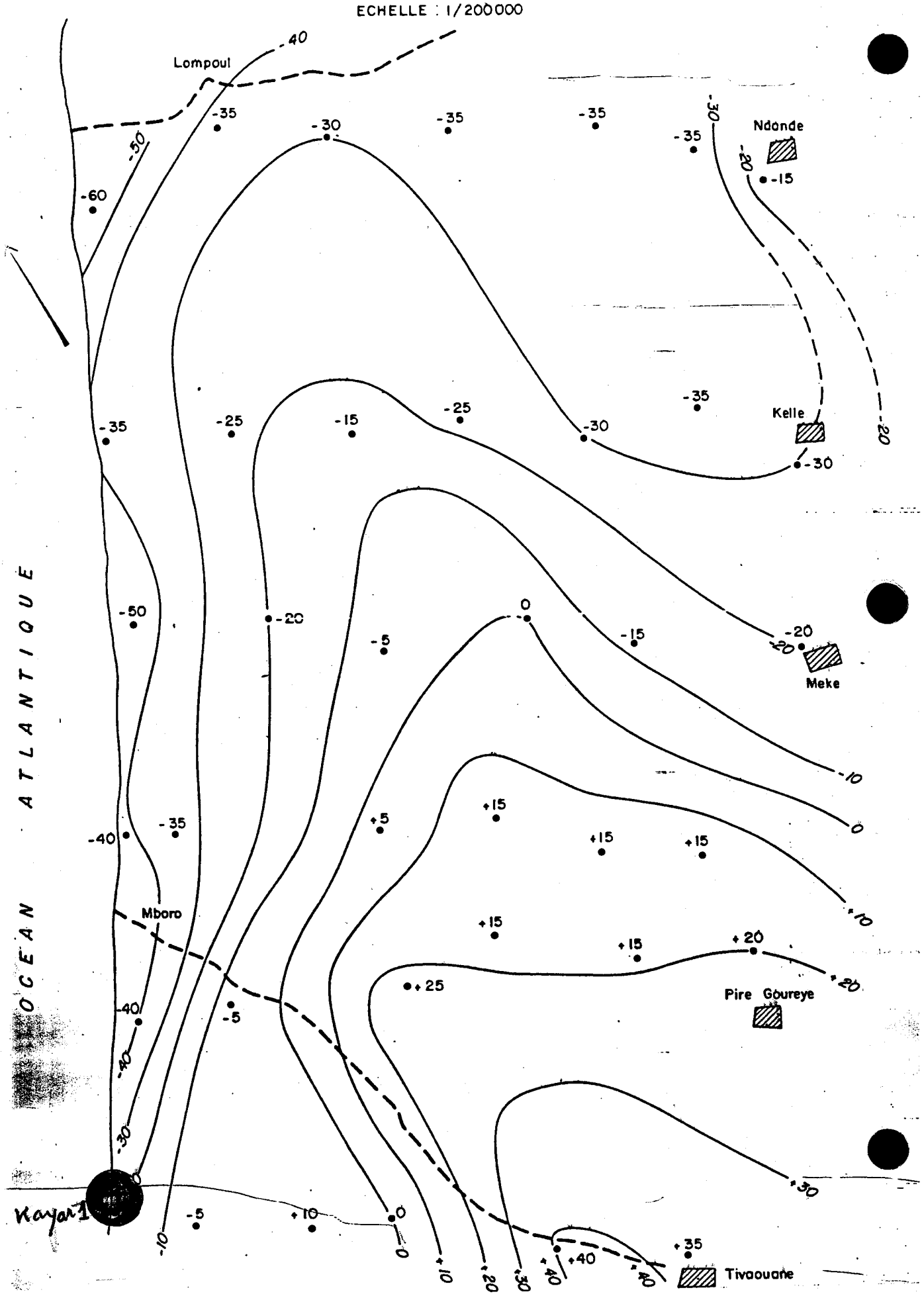
Structure du substratum

La structure générale est assez simple, les quelques ondulations existantes sont des bombements à grands rayons de courbure. La géophysique a montré un bombement à l'Ouest d'une ligne Pire-Goureye-Lompoul et un autre à l'Est de Louga. Un troisième bombement plus intense, celui de Léona, a été confirmé par les forages pétroliers.

ISOBATHES DU TOIT DU SUBSTRATUM

Fig. 3

ECHELLE : 1/200000



Au Sud, l'anticlinal affleurant du massif de N'Diass se prolonge vers le Nord par la structure de Mont Rolland et vers l'Ouest par un système de failles de direction générale NS.

2.5 LA CLIMATOLOGIE ET SES FLUCTUATIONS

La principale alimentation de la nappe étant due aux précipitations, les facteurs climatiques vont jouer un rôle essentiel dans le bilan apports-pertes par évapotranspiration et sous écoulement vers la mer.

Le climat de type tropical subcanarien comporte une saison des pluies de quatre mois (juillet à octobre) et une saison sèche de huit mois.

2.5.1. - *Les précipitations*

- Les données pluviométriques (tab. 2)

On dispose des données pluviométriques des 7 stations situées sur le pourtour de la zone occupée par la nappe des sables, à savoir du Nord au Sud: St Louis, Pal, Louga, Kébémer, Tivaouane, Thiès et Dakar.

La carte de la Fig. 4 résume les données recueillies pendant la période 1963-1975.

De plus, quatre autres stations se trouvent sur le périmètre de la zone concernée, à savoir du Nord au Sud: Lompoul, Diogo, Mboro et Mont Rolland.

Malheureusement, les données pluviométriques de ces stations sont souvent incomplètes et les mesures n'ont parfois été effectuées que pendant quelques années.

Tableau 2 - DONNEES PLUVIOMETRIQUES

Station	Lat.	Long.	Périodes	Années manq.	Nombre	Moyenne mm
St Louis	16°3'	16°27'	47-49			307,6
			01-30	02,14,15,28,30	25	390,4
			63-75		13	309,3
Pal	15°55'	16°16'	66-75	73	9	357,8
Louga	15°37'	16°13'	31-75	58-59-60	38	439,4
Kébémer	15°22'	16°27'	63-75		13	381,4
Tivouane	14°57'	16°49'	63-75		13	494,6
			31-75			575,4
Thiès	14°48'	16°57'	63-75	67	12	509,5
Dakar	14°44'	17°30'	47-79			503,5
			63-75			447,0
Lompoul	15°26'	16°43'	63-75	67,68,69	10	361,4
Diogo	15°18'	16°49'	63-75	65,68,71,72,75	8	443,8
M Boro	15°8'	16°53'	37-81		45	440,
			63-75		13	408,
Mr Rolland	14°56'	16°59'	51-71	64,69	19	599,8
			63-71		7	492,7

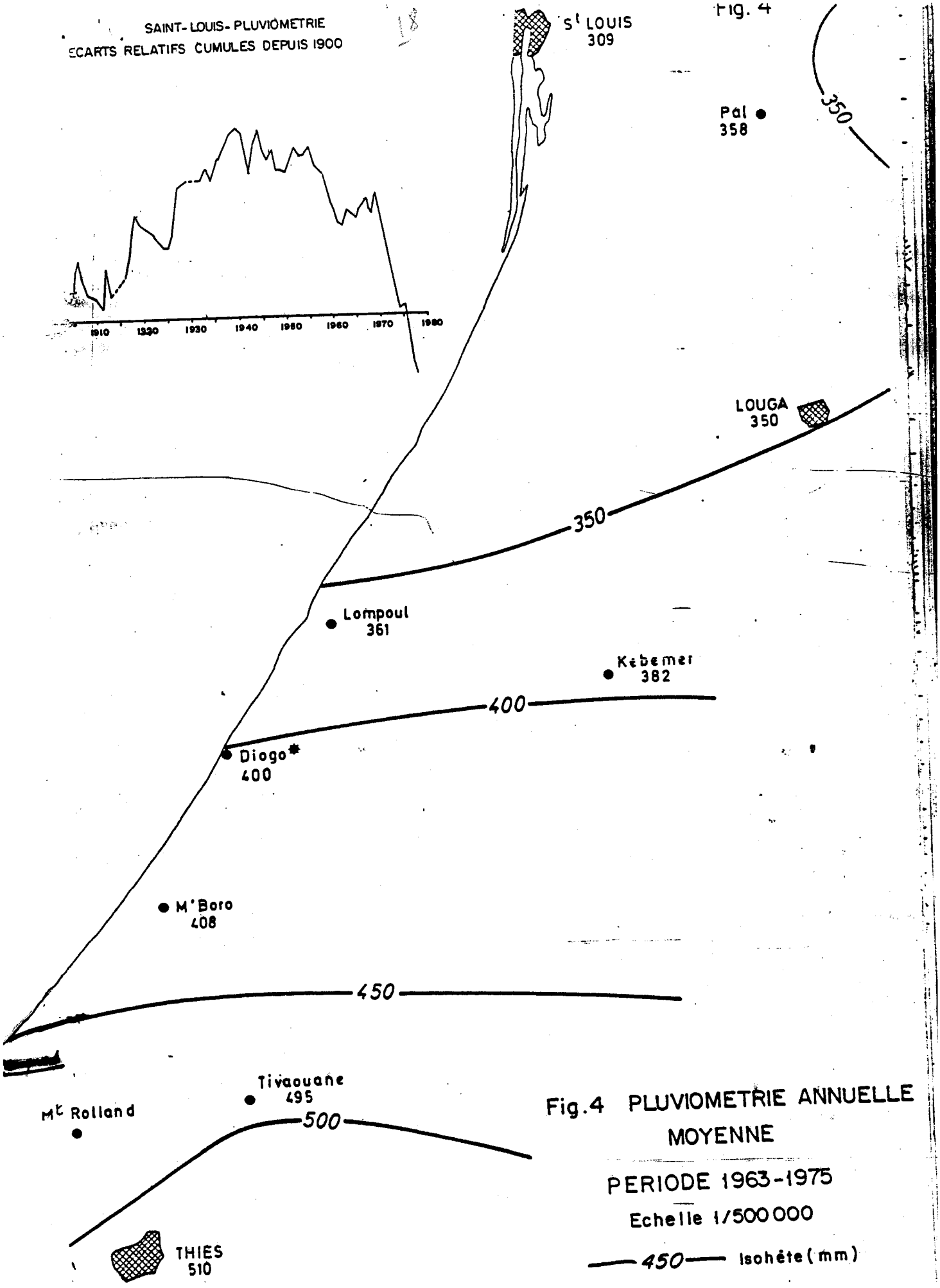


Fig.4 PLUVIOMETRIE ANNUELLE MOYENNE

PERIODE 1963-1975

Echelle 1/500000

450 Isohète (mm)

- Analyse des pluviométries annuelles

Les précipitations diminuent du Sud vers le Nord et augmentent à mesure que l'on s'éloigne du littoral (Fig. N° 4).

D'autre part, la courbe de variation de la pluviométrie à M'Boro de 1937 à 1981 montre une diminution très sensible depuis 1970 (Figure N° 5).

M'BORO : moyenne 70-81 : 325 mm
37-81 : 440 mm

De même, la courbe des écarts relatifs cumulés effectuée pour la station de St Louis montre un processus de dégradation continu depuis 1955 avec une stabilisation entre les années 1960 à 1970.

- Le régime des précipitations et leur intensité

Les pluies d'hiver sont très rares et de faible intensité. De juillet à septembre, il tombe en moyenne de 85 à 90 % des précipitations annuelles, sous forme d'averses courtes et violentes . Ainsi, les années fortement excédentaires sont généralement dues à la somme de quelques pluies violentes.

Ces années sont des périodes privilégiées pour la recharge de la nappe.

Même lors des années déficitaires, l'on observe des pluies de forte intensité. Ainsi à Lompoul ces dernières années, le maximum de précipitation journalière représente 20 à 40 % du total annuel:

Station de Lompoul	Nombre de jours de précipitations	Total annuel en mm	Maximum journalier mm
1975	23	439	91
1976	24	275,1	77,6
1979	27	177,1	41
1980	17	229,5	85,4
1981	24	256,8	86,5

Tableau 2a - PRECIPITATIONS JOURNALIERES ET ANNUELLES

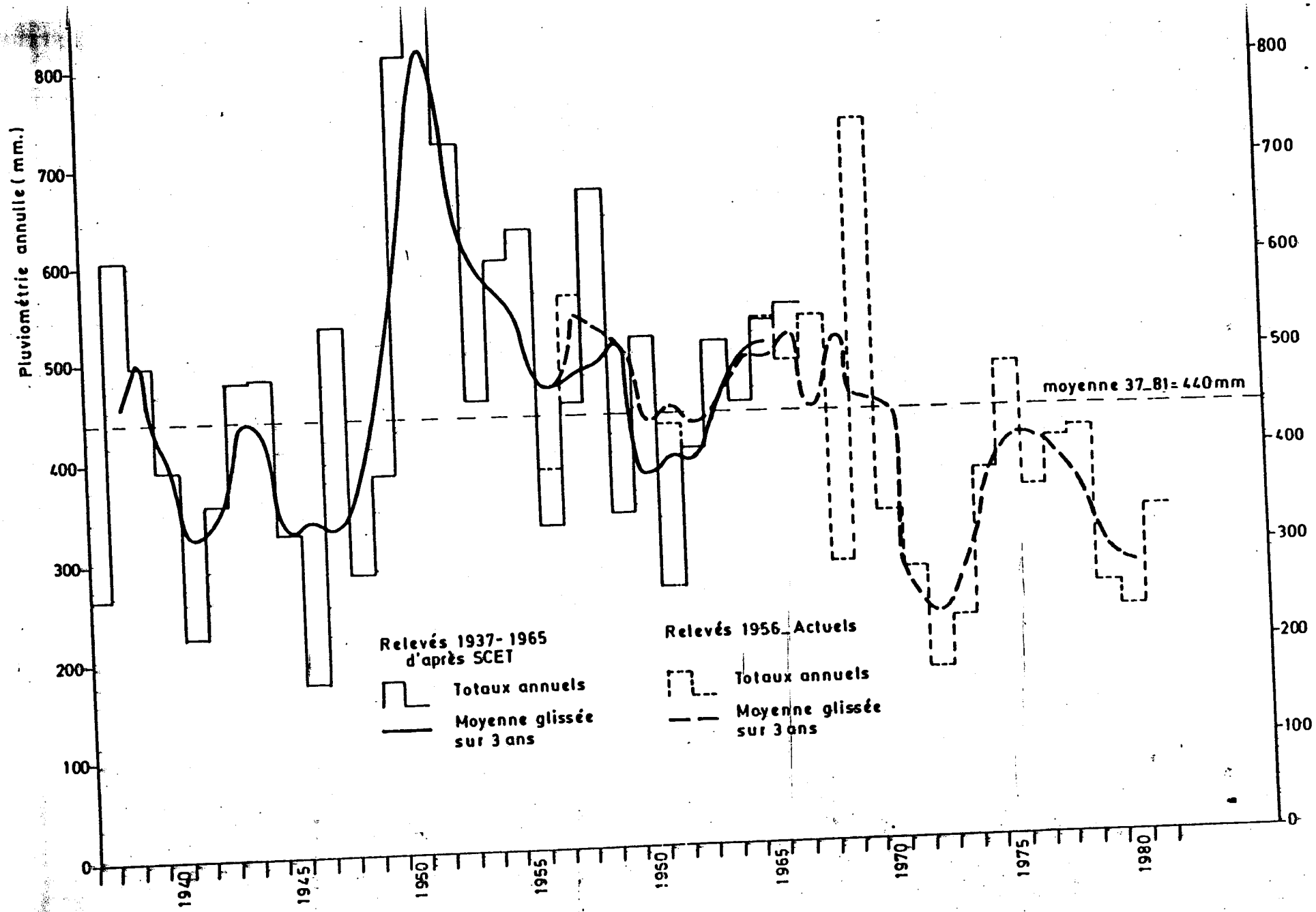

Pluviométrie annuelle (mm.)
800
700
600
500
400
300
200
100
0
1940
1945
1950
1955
1960
1965
1970
1975
1980
moyenne 37_81 = 440 mm
Relevés 1937-1965
d'après SCET
Totaux annuels
Moyenne glissée
sur 3 ans
Relevés 1956_Actuels
Totaux annuels
Moyenne glissée
sur 3 ans

Fig. 3

2.6 HYDROGEOLOGIE DES ZONES SABLEUSES

L'aquifère sableux couvre une superficie d'environ 2 300 km2 entre Tivaouane et Louga ; mais il présente des qualités hydrodynamiques inégales liées à la proportion des éléments argileux. Il comble une structure en chenal qui s'approfondit vers le Nord. Parmi les différents faciès décrits au paragraphe 2.4, seuls les sables fins à moyens éoliens présentent de bonnes caractéristiques de réservoir. Localement, ces sables peuvent être entrecoupés par des niveaux argileux (Carte des aquifères de la Fig. 7).

2.6.1. - *La piézométrie*

Les mesures concernent le système hydraulique constitué par les aquifères continus des sables quaternaires et des calcaires lutétiens.

- Historique des mesures

Une première carte piézométrique a été tracée en 1962 par J. Putallaz dans son rapport sur l'hydrogéologie des niayes. Les relevés de niveau du plan d'eau ont été étalés sur une période de 3 années consécutives, si bien que l'on n'aura pas une piézométrie indépendante des fluctuations temporelles de la nappe.

Ces fluctuations sont de deux ordres : fluctuations annuelles dues à l'alternance saison sèche, saison humide et inter-annuelles dues aux variations pluviométriques. De plus, les mesures ayant été effectuées dans des puits ne reflètent pas toujours la piézométrie exacte, du fait du puisage.

A partir de 1963, la S.C.E.T. a mis en place des piézomètres et échelles limnimétriques et a suivi jusqu'en 1965 les fluctuations de la nappe.

En 1974, l'OMS a mis en place un réseau de piézomètres qui a fait l'objet de mesures régulières jusqu'à nos jours.

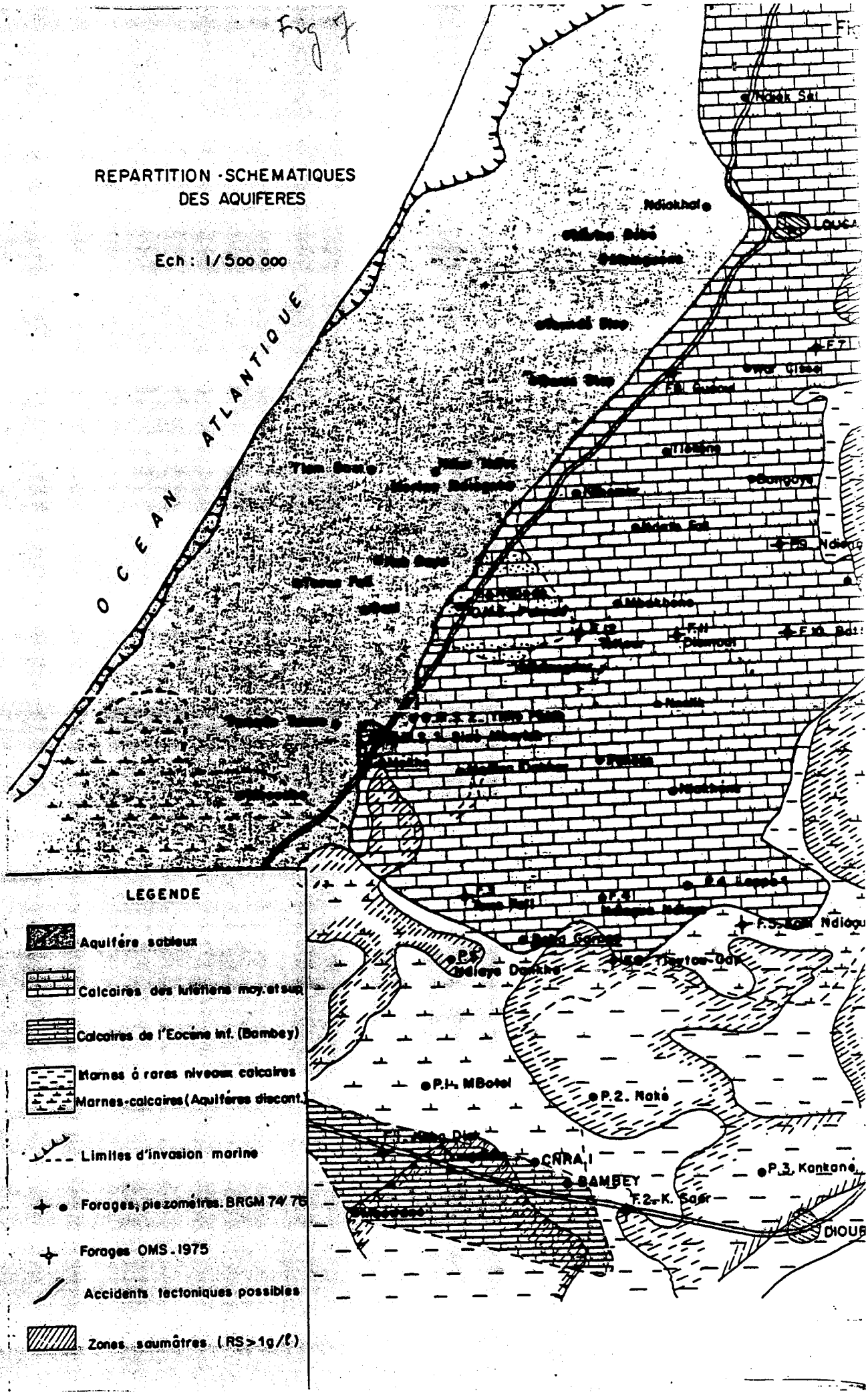
- Ecoulement de la nappe

On considérera la carte piézométrique établie par Y. Noël et concernant la situation de la nappe en juillet 1975 donnée en Annexe II avec des coupes géologiques détaillées à l'appui.

Fig 7

REPARTITION · SCHEMATIQUES DES AQUIFERES

Ech : 1/500 000



Elle est estimée à 50 mm pour les types de sols qui existent sur les dunes.

Les bilans obtenus sont les suivants pour les années 1954 et 1955 (Tableau 3) (d'après S.C.E.T., 1968).

Tableau 3 - Bilan hydrique

Mois	Juin	Juillet	Août	Septembre	Octobre	Total
E.T.M. mm	153	138	120	136	136	783 mm
Pluie 54	37,8	96,9	336,0	118,8	9,6	600,6 mm
Réserve du sol	0	0	50	32,8	0	
Excédent	0	0	166,0	0	0	166,0 mm
Pluie 55	96	115,0	282,8	134,2	-	632,0 mm
Réserve sol	0	0	50	48,2	0	
Excédent	0	0	112	0	0	112,0 mm

A défaut de mesures suffisantes, un bilan hydrique mensuel a été établi en considérant comme valeur d'évapotranspiration, celle calculée par la formule de Turc et en prenant comme réserve temporaire du sol celle utilisée par les agronomes, dénommée "réserve facilement utilisable". Cette réserve sature les premiers mètres du sol et elle est consommée après les pluies par l'évapotranspiration de la végétation temporaire qui suit les pluies.

On constate que les excédents disponibles pour l'infiltration ne sont pas forcément proportionnels à la pluie totale de l'année ; ils sont liés à la distribution de la pluie au cours de la saison des pluies et sont d'autant plus importants que celle-ci a été plus concentrée sur un mois.

La moyenne des excédents calculée sur 30 ans (de 1937 à 1966) s'établit à 89,1 mm/an, soit 20 % de la pluie moyenne. Elle peut atteindre 316 mm et 47 % de la pluie. Sur 30 ans, le calcul a donné 9 années avec un excédent nul.

On remarque qu'un bombement piézométrique très accusé et allongé parallèlement au littoral est axé sur l'aquifère. Il s'affaisse progressivement vers le Nord (gradient moyen : 0,4 ‰). Il correspond à une zone d'infiltration privilégiée due à la pluviométrie sur le "plateau" de Taïba, à l'Est de Tivaouane.

Vers le Nord, on remarque une piézométrie plane couvrant l'aquifère calcaire fortement perméable. Aucun axe de drainage n'est vraiment perceptible.

Vers l'Est, un écoulement s'effectue en direction des calcaires lutétiens à partir du bombement des sables, la pente de la nappe s'annulant très rapidement à l'Est de la route Thiès-St Louis.

Pour juillet 1975, Y. Noël a calculé un apport de 0,35 m3/s soit 30 000 m3/j en direction des calcaires.

Vers l'Ouest, la nappe s'écoule vers l'océan et vers le Sud, l'allure mouvementée des courbes s'explique par l'existence d'un substratum à relief prononcé résultant d'un ancien réseau hydrographique, et par l'existence de zones préférentielles d'écoulement dues à des différences de perméabilité.

2.6.2. - *Hydrochimie*

- La conductivité

L'aquifère des sables quaternaires se caractérise par une conductivité faible à très faible, le plus souvent inférieure à 500 micromhos/cm, sauf dans les zones littorales, notamment autour de M'Boro, un peu au Nord de Lompoul et surtout à l'approche du delta du Sénégal et au Sud, à l'approche de la région du lac Tamna.

On remarquera que la zone de plus faible conductivité (inférieure à 200 mhos/cm à 25° c) peut se superposer à l'axe du bombement piézométrique, indiquant donc une alimentation préférentielle de la nappe par les précipitations dans cette zone.

En ce qui concerne les variations annuelles, on remarquera que, pour les mesures effectuées dans le Sud, en général, les plus faibles teneurs correspondent au maximum de remontée des puits.

- Les faciès hydrochimiques

Le faciès dominant est le faciès chloruré sodique dans lequel prédomine le type chloruré calco-sodique.

En bordure du littoral, on rencontre des eaux à faciès mixte essentiellement du type sulfaté calcique-chloruré sodique.

Enfin, à l'Ouest de Kébemer on notera la présence d'eaux de faciès bicarbonaté calcique.

On relève parfois de fortes teneurs en nitrates, essentiellement à l'Est de M'Boro, jusqu'à Méouane (parfois supérieures à 45 mg/l de $NO3^{-}$ = teneur maximale OMS pour la potabilité) et sur une zone plus réduite, au Nord Ouest de Louga.

Ces fortes teneurs sont à mettre en relation avec la monoculture des arachides provoquant une concentration des nitrates dans le sol.

Quelques fortes teneurs en fluor ont été enregistrées notamment entre Kébémer et Lompoul (4 à 8 mg/l).

De même, de fortes teneurs en fer se trouvent dans les eaux des forages du périmètre agricole de Diogo (5 à 15 mg/l), et dans les céanes de certaines niayes on remarque des dépôts d'oxyde de fer.

REPUBLIQUE DU SENEGAL
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DIRECTION DE LA
METEOROLOGIE NATIONALE

CLIMATOLOGIE

PLUVIOMETRIE

Imp. GUT. - Dakar

KAYAR	Janv.	Févr.	Mars	Avril	Mai	Juin	Juillet	Août	Sept.	Oct.	Nov.	Déc.	An
1981						40.2	52.0	143.9	103.2	0.3			339.6
1982							63.1	143.0	41.5	12.1			259.7
1983								73.1	21.4				94.5
1984													
1985						22.1	34.1	114.1	84.9	0.3			255.5
1986							30.2	101.1	188.9	1.2			321.4
1987													
1988													
1989						31.5	142.5	418.1	89.1	14.0			695.2
1990							75.0	111.0	121.4				307.4
1991						13.5	8.0	50.5	35.5				107.5
1992		5.0					15.5	141.0	37.0				198.[illegible]
1993							89.0	78.0	115.0				232.[illegible]
1994						18.0	18.0	101.0	60.0				197.0
1995							35.0	80.0	104.0	9.0			228.0
1996							21.0	40.0	85.0	8.0			154.0

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CLIMATOLOGIE

PLUVIOMETRIE

Imp. GUT. - Dakar

THIES	Janv.	Févr.	Mars	Avril	Mai	Juin	Juillet	Août	Sept.	Oct.	Nov.	Déc.	An
Années	Hauteur			Nombre de Jours									Hauteurs
1976	407	6		33	jours								407,6
1977	288	1		21									288,1
1978	605	6		51									605.6
1979	626	5		47									626.5
1980	409	1		36									409.1
1981	482	7		42									482.7
1982	461	6		36									461.6
1983	240	8		24									240.8
1984	320	0		31									320.0
1985	404	3		47									404.3
1986	367	9		36									367.9
1987	416	7		38									416.7
1988	509	1		45									509.1
1989	606	8		43									606.8
1990	408	7		37									408.7
1991	335	1		36									335.1
1992	304	3		38									304.3
1993	305	9		34									305.9
1994	423	9		43									423.9
1995	515	1		49									515.1
1996	389	4		32									389.4
1997													

FORAGES EXISTANTS

DANS LA ZONE DE KAYAR

	MBIRDIAM	DIENDER NDAM	BER TIALANE
Année de Réalisation	1970	1982	1996
Profondeur	180 m	247	240
Débit	300m3/h	49m3/h	300m3/h
Niveau statistique	27m, 60	50	48m

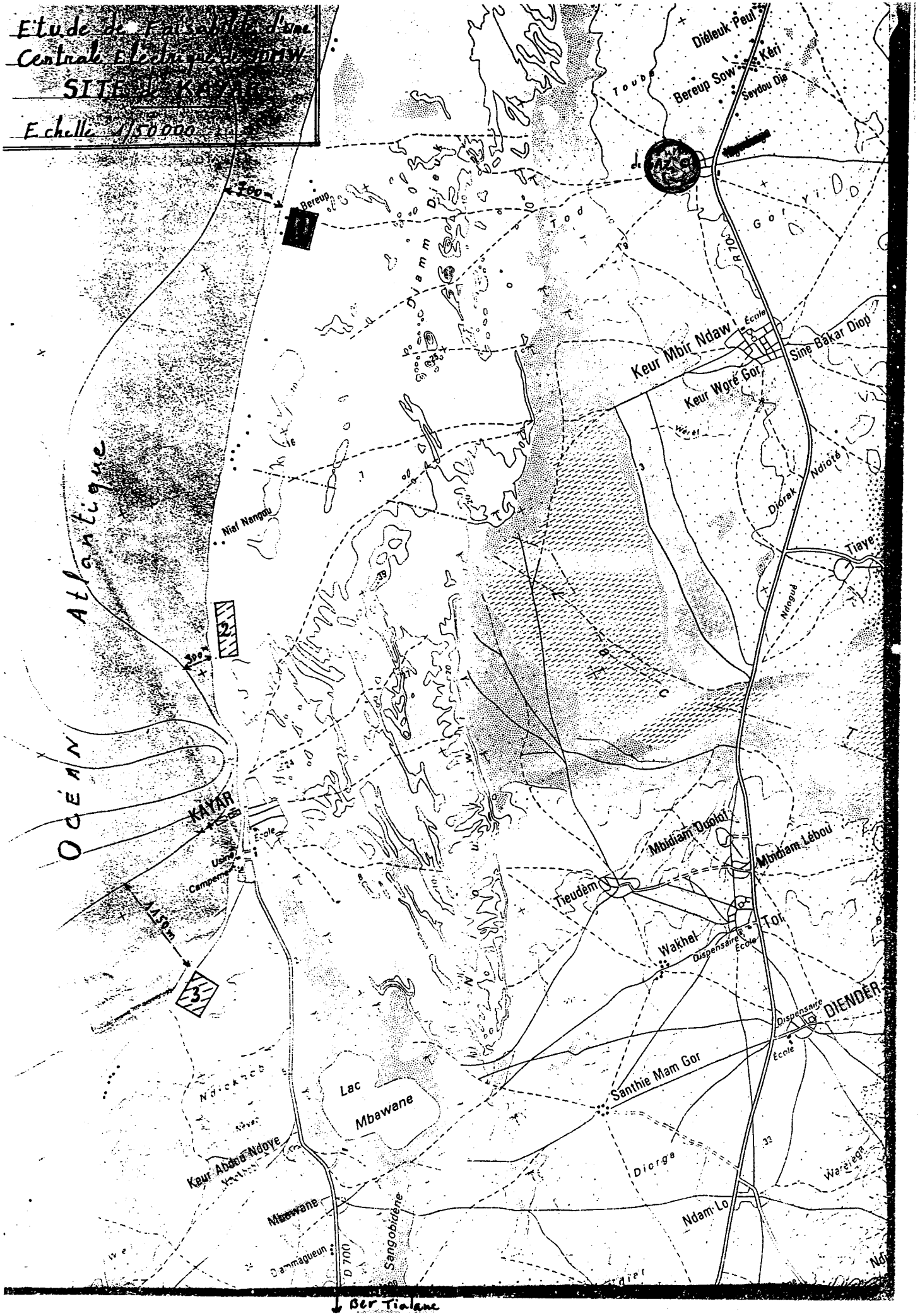
FORAGE ET CHATEAU D'EAU PREVUS

	Entre Keur Abdou Ndoye et MBAWANE FORAGE	A KAYAR Château d'eau de 300 m3
Année de Réalisation	1999	
Profondeur	250m	
Débit	100m3/H	
Niveau statique	50m	

Etude de Faisabilité d'une Centrale Electrique de 5MW

SITE de KAYAR

Echelle 1/50000



Appendix H:
Selected Barge Mounted Power Plant Articles

Select Barge-Mounted Power Plant Articles which are either not copyrighted or are reprinted with permission are presented here for the interested reader. Numerous other articles can be found in the open literature.

Turnkey Contracting

The Power Barge Option

By Christopher Kane and H. Clayton Cook Jr., Bastianelli, Brown, Touhey & Kelley

International power development offers vast opportunities for turnkey delivery of barge-mounted power plants. Such projects are going forward in all parts of Asia, Africa the Middle East and the Americas, providing developing nations quick delivery of much needed power.

A few years ago, barge projects were in the 5 MW to 25 MW range. Today's projects are being offered in the 40 MW to 450 MW range using advanced, efficient and clean gas-turbine combined-cycle technology. For example, Westinghouse Electric Corp., in a variety of roles, has 1,200 MW of power barges under contract, in construction or in operation worldwide. Westinghouse is also supporting the development of numerous other projects around the world. A current project involves supplying design support and equipment for the Wing Tiek combined-cycle facility, a 288 MW power barge under construction in Pakistan. The Parsons Power Group is acting as the engineer on this project and other projects for Westinghouse.

There are several advantages to building these power generation projects in a shipyard for a developing country. One is that favorable project financing opportunities sometimes become available. Another advantages is the ability to achieve faster deliveries than with land-based construction projects. To a large extent this is due to the controlled environment of the shipyard where the majority of the fabrication, assembly, outfitting and testing takes place. Delivery times in the range of 12 to 14 months are readily achievable, and deliveries as low as six months are possible for standardized designs where advanced procurement has been undertaken. In addition, some firms are building power barges on speculation which can further accelerate delivery.

In addition to quick delivery, power barge projects open the door to shipyard-based financing opportunities as well as the traditional project finance and export credit agreement resources. In the United States, projects become eligible for financing by U.S. Maritime Administration (MARAD) under Title XI. Projects using U.S. equipment might also qualify for involvement by the Export-Import Bank of the United States (U.S. Ex-Im). Some non-U.S. shipyards also can offer attractive financing arrangements in order to obtain the shipbuilding contracts.

Banks and other lending institutions are more comfortable in providing loans to an emerging market project, when secured assets can be retrieved in the event of a default on the loan. The shorter lead time in delivering these projects and generating electricity also greatly reduces carrying costs during construction.

Besides the financial advantages, the shipyard environment allows greater quality control than a traditional construction site. Furthermore, the ability to perform pre-testing of the components and systems can reduce construction cost and reduce the risk in start-up and turnover. The exposure of the project to political risk during construction can also be minimized by having the majority of the construction take place at a shipyard in a developed country.

In Ghana, Westinghouse is acting as turnkey contractor, with Parsons Power serving as engineer on a simple-cycle barge project. This 120 MW project is about to begin construction at a U.S. Gulf Coast shipyard with government guaranteed financing. Parsons Power is the overall designer, and there is a subcontract with a marine engineer to design the barge platform. By building the plant in modularized units using multiple barges, projects like this one can be delivered and started up in stages.

Turnkey Contracting

Under a turnkey contract, the builder undertakes to furnish all the components of a project. This includes performing design and construction to complete the plant; providing testing and start-up; and placing the plant in production. Power barge projects are well-suited for turnkey contracting. Turnkey places all design, construction, ship building and performance responsibilities under a single entity. The primary advantage to turnkey work is this single point of responsibility.

While the ultimate form of the turnkey venture varies, it can be done by a lead company, which subcontracts out the different aspects of the project. Another approach is having the principal participants join in a consortium or joint venture arrangement. The goal under either framework is to appropriately allocate and assign the risks to the party best able to control that risk. Schedule, performance and price guarantees can thus be provided with a maximum amount of risk sharing and a minimum opportunity for disputes.

Construction of the on-shore facilities—switchyard, fuel supply and storage, and mooring facilities—could either be owner-provided or part of the turnkey contract. For the Ghana project, the developer is undertaking the on-shore work as part of a larger project including a port development, pipeline and transmission line construction. The on-shore interfaces must in all cases be carefully coordinated with the turnkey contractor and responsibilities clearly defined among the parties. Otherwise the owner will quickly lose the main advantage of its turnkey contract.

Shipbuilding and Delivery

In power barge projects, contracting for the required shipyard construction and barge delivery are critical issues. In many cases the choice of shipyard can determine the financing. In the United States, for example, shipyards can offer

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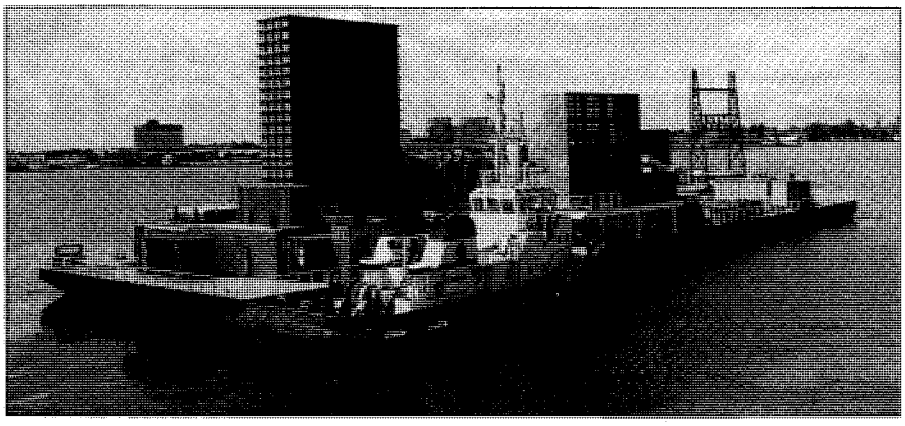

Turnkey construction on barge-mounted power projects is proving to be an ideal way to quickly meet capacity needs in emerging markets. Westinghouse Electric Corp. supplied a 103 MW combined-cycle project in Manila, the Philippines, for Sabah Shipyard of Malaysia.

access to financing from MARAD and U.S. Ex-Im Bank. Shipyard construction in other developed countries also offers similar advantages.

The turnkey contractor subcontracts separately with a shipyard and an engineering firm to act as project engineer. Either the project engineer or the shipyard then subcontract with a marine engineering firm to sign off on the barge design. Under MARAD-financed projects, MARAD will want the maximum amount of work performed by the shipyard since the purpose in providing Title XI financing is to encourage increased production at U.S. shipyards.

The shipyard has principal responsibility for the barge platform. The project engineer however provides input to the barge design including loading requirements, tolerance and alignment criteria. The power plant superstructure will normally be built as a separate package, and the project engineer provides the superstructure design. Separate construction contractors will be used since the shipyard normally would not have the required expertise.

Another critical aspect of the barge project is delivery of the barge from the shipyard to the point of use. The turnkey contractor would presumably bear risk of loss until the barges are turned over to the developer at the site. Thus the contractor must work with a responsible ocean-going tug operator or heavy ocean transportation company to deliver the barges and ensure that there is adequate insurance coverage to insure risk of loss or damage during transport.

Financing Options

A project that can be financed will require long-term, creditworthy contracts for the power purchase and other key elements like fuels and operations and maintenance (O&M). In many cases in today's market, the lender will require that the power purchase agreement have some form of sovereign guarantees. The project should also contain an appropriate allocation of risk to the parties best suited to manage those risks.

All the major contracts, such as the turnkey contract, power purchase agreement, fuel supply contract and the O&M agreement will be reviewed by the lender, who frequently uses an outside consultant. The lender attempts to insure the capability of the contracting parties and the viability of the guarantees offered for cost, schedule and performance. Total project cost should be comparable to projects of similar type and size for a particular market. Pricing and cost should reflect market-based pricing.

A sensitivity analysis typically will be done to determine a sufficient debt service coverage ratio to ensure uninterrupted debt servicing for the term of the debt. Often a debt reserve of six months to one year is required to cover debt service during disruptions to the project to avoid triggering a default.

In the United States, MARAD has been providing financial guarantees for ship construction since the early 1970s as a stimulant to commercial production. MARAD will provide debt guarantees for up to 87.5 percent of the actual cost of the power barge. Terms for MARAD guarantees are up to 25 years, and the interest rate is a market-determined rate with MARAD paper selling at 60 to 70 basis points above comparable U.S. Treasury bonds. There is a MARAD guarantee fee which will vary between 0.5 percent and 1 percent based on project risk. In combination, these terms are substantially more advantageous than most any other commercially available financing.

MARAD financial guarantees have been approved for what will be the largest power barge project ever built. The WAK Orient Power and Light Project has received approval for more than $400 million in MARAD guarantees on its six-barge combined-cycle project being built by a consortium of Westinghouse and Raytheon Engineers and Constructors in Pakistan. Pakistan provided guarantees for the power purchase agreement, while the prime shipyard for construction of this project is expected to be in the United States. Since 1994 MARAD has approved guarantees on 13 power barges totaling more than $550 million.

U.S. Ex-Im has direct loan, guarantee and insurance programs which assist the export of U.S.-sourced capital equipment, projects and services. Eligible exports include engineering and design services, power generation and transmission installations, such as power barges. This includes financing of up to 85 percent of the U.S. contract price, interest accrued during construction and an allowance of up to 15 percent foreign content, typically made up of local construction costs.

The interest rates on U.S. Ex-Im financing are 100 basis points above U.S. Treasury rates plus an exposure fee based on project risk. The term of the financing support is a maximum of 12 years. Again the application process is relatively quick and should not be cause for scheduling delays on a project. However, getting a U.S. Ex-Im loan to closing is similar to any bank and requires due diligence, legal fees and transaction fees.

Considering the faster delivery schedules, easier access to financing sources and the ability to perform construction in a more stable environment, the benefits to power barges are numerous. As well, the turnkey approach to barges also puts performance responsibility under a single entity, which should reduce disputes and thus further improve project delivery. As the industry continues its expansion worldwide, the power barge option is one that must be given serious consideration when the circumstances warrant. ■

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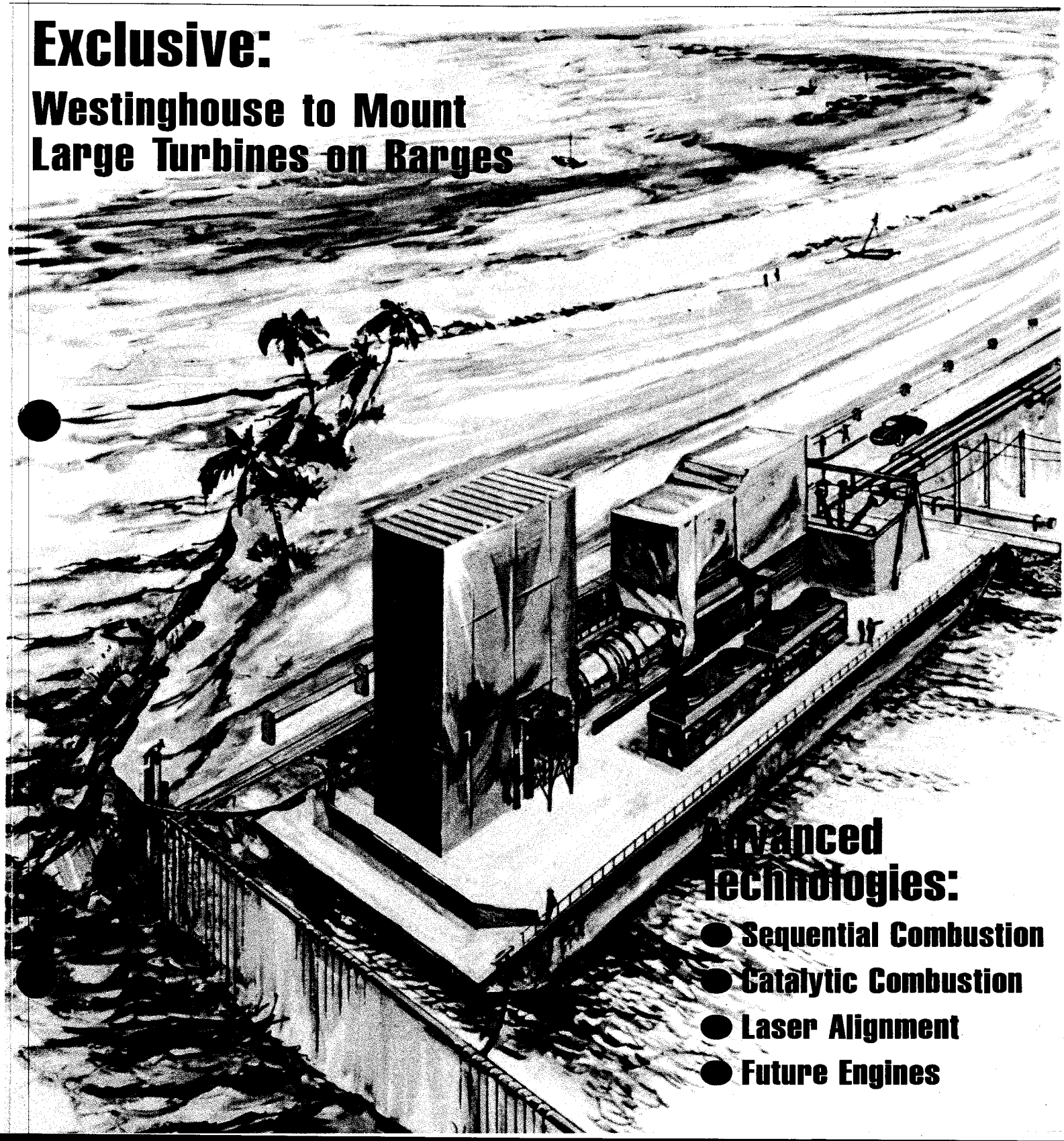
January/February 1994 Vol.35 No.1

Turbomachinery INTERNATIONAL

Covering the selection, operation, maintenance and overhaul of rotating equipment.

Exclusive:

Westinghouse to Mount Large Turbines on Barges



Advanced Technologies:

- Sequential Combustion
- Catalytic Combustion
- Laser Alignment
- Future Engines

can be assembled and tested on site. Transportation strategies have been developed to move approximately 1400 tons, and the engineers have designed each module to weigh under 1400 tons.

Production Network

Westinghouse is now in the process of setting up a global network of shipyards which can construct the barges and package assemblies. General Dynamics' manufacturing facility in Charleston, South Carolina is one facility under consideration. **Turbomachinery International** has learned that negotiations are underway to form a new company in Charleston, Marine Energy Systems Corporation, which would handle construction of the platform and assembly of the power plant modules, as part of a Westinghouse turnkey power plant project.

Working in parallel, the Sabah Shipyards in Labuan, Malaysia is now constructing their own barge-mounted package using the Westinghouse 501D5 Econopac. This Sabah Energy Barge was designed by the Sabah Shipyard with assistance from Westinghouse. The design is different from the Westinghouse concept in that it is not modular.

Sabah's is a simple-cycle system with a Brush-Westinghouse generator, two small diesel-powered generators for black starts, and a Westinghouse Power-Logic II control system. The 60-Hz, 110-MW gas turbine will burn naphtha, with distillate used for start-up and as an alternative fuel. When completed this spring, it will be the largest barge-mounted powerplant to date (although some of the Westinghouse-designed units are to be larger). It will go to a client in the Pacific for base load power.

Aside from the additional turbine sales, the major importance of the barge project is what it says about Westinghouse power system development. The company is now seeking greater modularity in all of their power system projects, with the attendant benefits of quality, reduced construction time, and savings.

Westinghouse's Turbine Factory (Among Other Things)

The Westinghouse plant in Pensacola, Florida is the final assembly point for the 501 gas turbines. They also manufacture electric generators and build/rebuild steam path components for steam turbine and nuclear plants. But these are only the latest in a series of state-of-the-art products from this 261,000-square foot facility.

When the plant was dedicated in 1968, they constructed internal components for nuclear reactor vessles. They began a few years in the defense business in 1982, building, among other things, submarine hulls, missile radio dishes and missile launchers. In 1987 they built their first electric generator. When the Westinghouse management decided to build gas turbines in the US in 1990 (after not doing so for five years), it was the Florida facility which got the assignment. (The first engine was shipped on January 30, 1991.) Steam chests and valves for controlling the flow of steam into steam turbines were added in 1993.

The key to such versatility is of course the work force. According to Len Miniszak, Area Manager, Combustion Turbines at Pensacola, it takes three years on the job to properly train an employee, but then that worker can do whatever needs to be done. 'One person might be installing fuel nozzles (today). Tomorrow he might be doing piping, and the day after that installing insulation blankets.'

The gas turbine assembly area can handle up to three engines currently. Working three shifts, their maximum output is eighteen units per year. (If orders require more than this, they would need to set up additional work stations.) Components for the gas turbines come from other Westinghouse branches and from a network of suppliers. Rotors, for instance, arrive fully-assembled from plants in Hamilton, Ontario and Charlotte, North Carolina.

It is difficult to say what Westinghouse will need in five or ten years, but it seems likely that Pensacola will be able to build it.

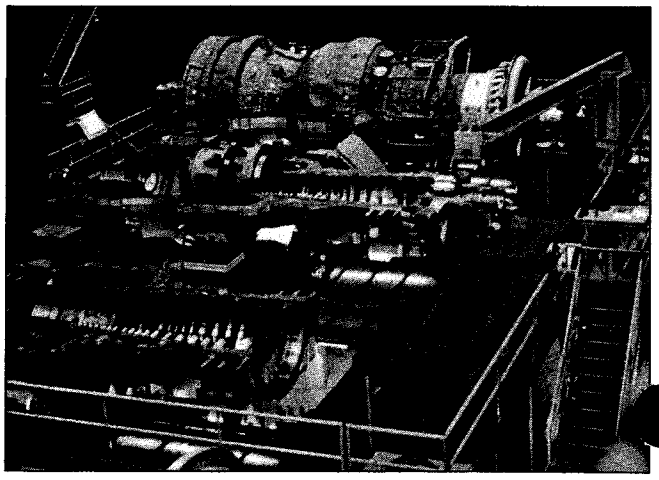
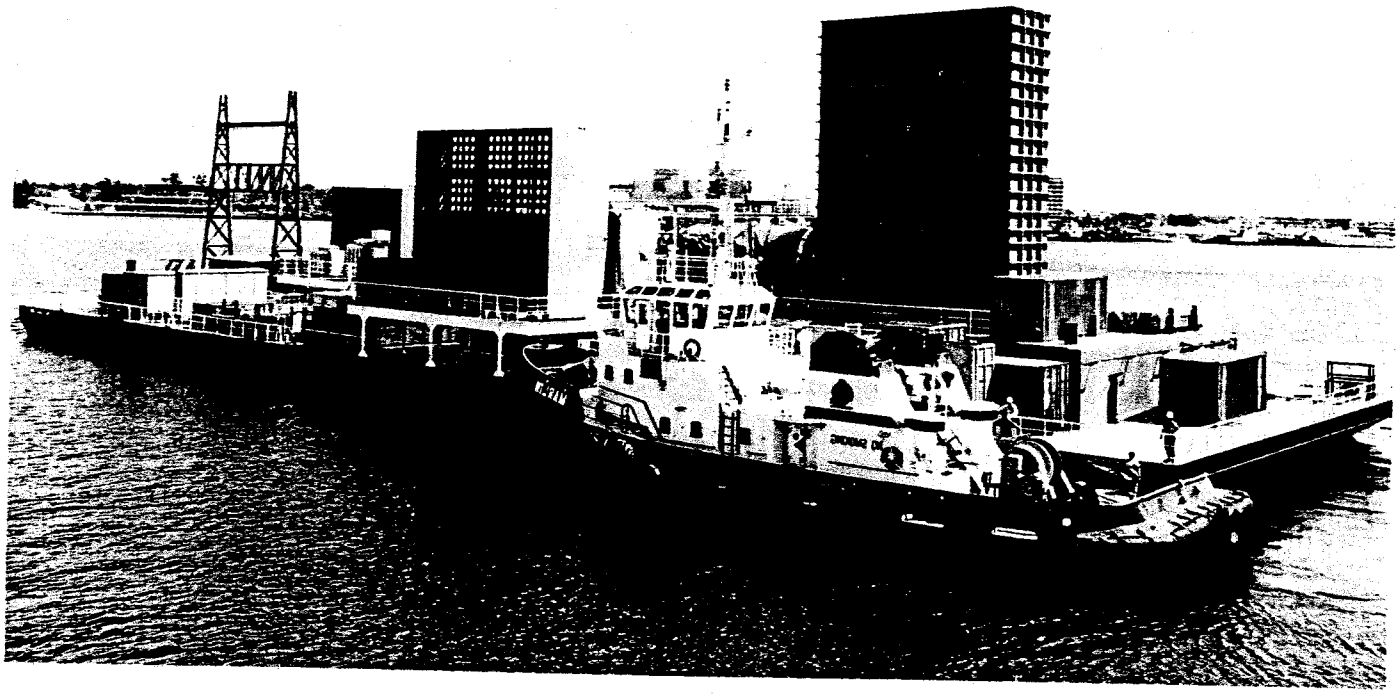


Fig.3
Westinghouse 501 gas turbines during final assembly at Pensacola.

Gas Turbine World

REPRINTED FROM NOVEMBER/DECEMBER 1995 VOL. 25 NO. 6



144 MW barge mounted plant for Ghana NPC puts power on-line fast

144 MW barge mounted plant for Ghana NPC puts power on-line fast

By Robert Farmer

Simple cycle and combined cycle power barges rated from 48 MW to over 200 MW can bring power on-line quickly — for as little as $425 per kW.

Late last year, Ghana National Petroleum Corporation (GNPC), the state-owned oil company, signed a turnkey construction contract with Westinghouse Power Generation to design, build and install a 144 MW (ISO base load) floating power plant in coastal Ghana near the Ivory Coast.

The barge mounted plant will power GNPC's ambitious offshore Tano Field Development and Power Project that includes offshore gas and oil field production, a gas pipeline system, and electric power transmission system installation—in addition to the floating power station.

GNPC is budgeting the overall Tano Field Development and Power Project at around $200 million. Although contract prices were not released, the barge power plant itself is estimated at $425 to $450 per kW ISO. The simple cycle plant is designed around two power barges:

☐ **Barge One.** Houses two dual-fuel 251B11 gas turbine generator packages (each ISO rated 48 MW on natural gas), inlet and exhaust, the power train isolating foundations, switchgear and personnel building, controls and auxiliaries, maintenance crane, and main power transformers all mounted on a 85 x 205-ft barge.

☐ **Barge Two.** Contains one dual-fuel 251B11 generator set package operable on natural gas and distillate, genset controls and auxiliaries, inlet and exhaust systems, the power train foundation, pedestal crane, and main power transformer on a 60 x 205-ft-barge.

Right now, barge construction is expected to begin early next year at a US-based shipyard on the Gulf of Mexico. Commercial operation of Ghana Tano is slated for early 1997.

All the power from the Tano plant will be sold to the Volta River Authority (the state-owned electric utility) for distribution throughout the nation. VRA is currently finalizing the long-term purchase contracts with GNPC.

In addition to the offshore oil and gas fields, GNPC will own and operate the natural gas pipeline that will provide fuel gas to the floating power station under a long term fuel supply agreement.

An investor-owned operating subsidiary is now being formed by GNPC to own the shoreside facilities and the electrical transmission lines to bring the power to VRA substations.

At average Western Ghana site conditions — air temperature of 26.4°C (79°F), barometric pressure 1013.2 mbar, and relative humidity up around 93% — the plant will have a net output rating of 131.5 MWe available to VRA. The plant will operate base load about 8200 hours per year.

The power barges themselves will be owned by a US Limited Partnership and leased to the Ghanaian operating company. They will be moored in a protected harbor near shore.

Plant economics

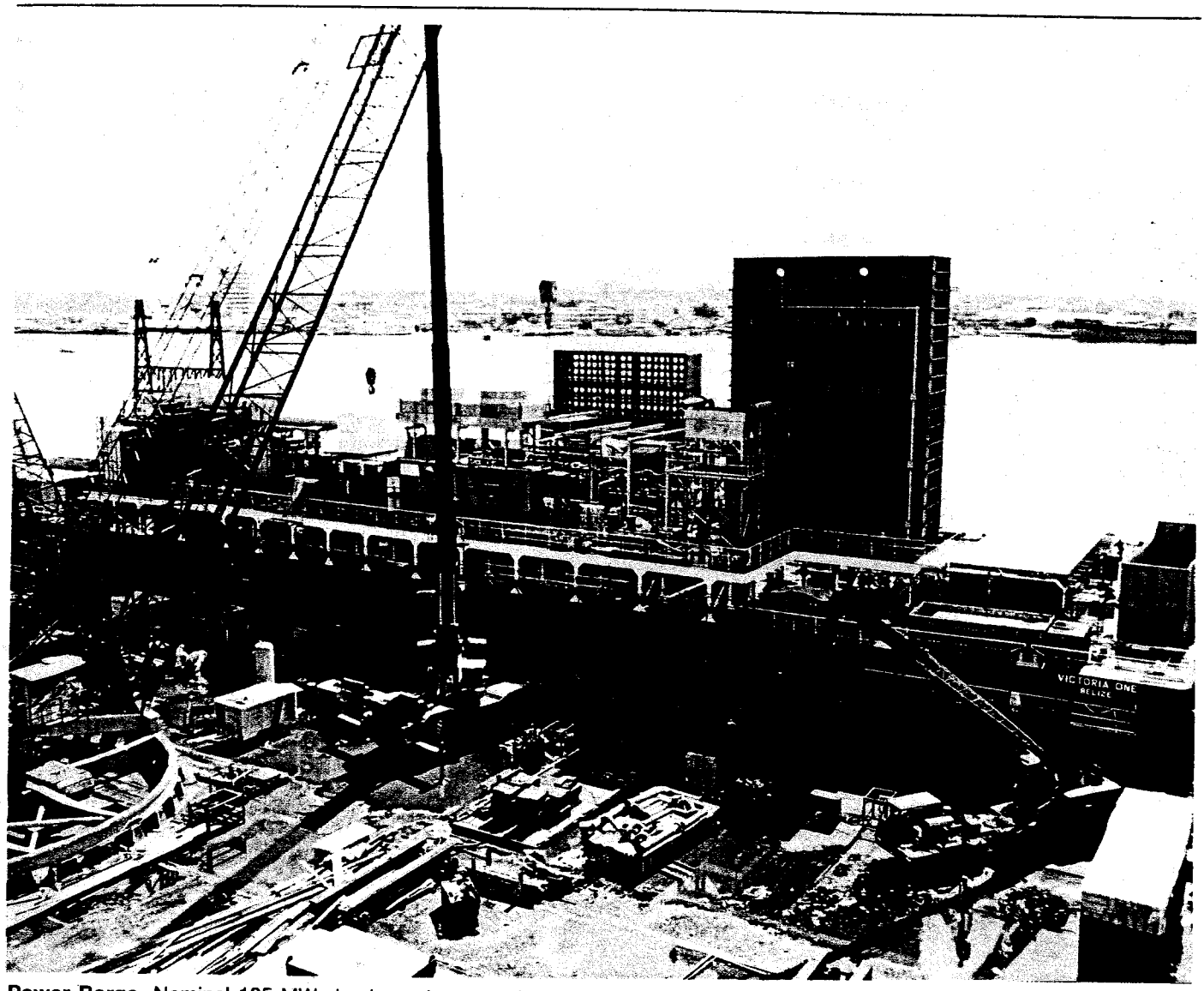
GNPC's barges will initially be simple cycle packages — with design provisions for future conversion to combined cycle.

Plant prices will vary depending on customer specifications, but in general, says Westinghouse, a 144 MW (ISO) simple cycle power barge will range from around $425 to $450/kW installed. Combined cycle barges cost more because of the additional equipment.

According to Westinghouse, power barge marketing head, Greg Snyder, "initial capital costing, on a $ per kW basis, is expected to be about the same as most US land based power plants (slightly higher for simple cycle configurations and slightly lower for combined cycle).

"But, plant location plays a big role. It can result in significant overall project savings if equivalent land based plant had to be built in a remote area (such as Western Ghana) requiring significant infrastructure investments and improvements."

He stresses that financing and overall project costs, on the other hand,



Power Barge. Nominal 105-MW simple cycle power barge under construction at Sabah Shipyards in Labuan, Malaysia includes the largest single gas turbine ever put on a vessel, the Westinghouse model 501D5. Power barge has now been operating in Manila, the Philippines, since October 1994.

should be considerably less expensive for the barge plants due to:

Shorter lead times. Generally less than one year for simple cycle delivery and less than two years for combined cycle delivery. Results in lower interest expenses.

Shorter startup cycle. The barge mounted plants are fully finished and partial load tested in the shipyard and ready for immediate service at site arrival.

Higher quality. Also results in faster startup cycle. Power barges are built in a controlled environment and pre-tested, not 'stick built' in the field.

Lower financing fees/rates. Since the construction risk is effectively mitigated and the asset is relocatable. In less remote locations, additional savings can be incurred by reduced real estate requirements.

Dry NOx specified

The Ghana gas turbines will be fitted with dry low NOx combustion systems. While there are no rigid atmospheric emissions regulations in effect in remote Western Ghana, GNPC wanted to eliminate the expense and complexity of an offshore water treatment facility that would have been required for NOx reduction with fluid injection.

Likewise, the power barges are not located close to densely populated areas, but the sound level nevertheless will be limited to 52 dB(A) at 950 meters which is the distance to a nearby small fishing village.

Primary fuel will be natural gas supplied from the offshore platform with No. 2 distillate oil bunkered at the barge shoreside as an emergency backup fuel.

Engineering, procurement, and project management for the GNPC sets is being performed at the Power Generation business unit headquarters in Orlando, Florida.

Westinghouse will build the power barges on a complete turnkey basis, transport them to the site in Ghana,

start up, test and commission the plant and then provide long term operating and maintenance management services. GNPC personnel will handle the day-to-day plant operations.

Westinghouse will assist GNPC in selecting qualified Ghanaian operators, also train them in the US and at the plant site. The US training program will include extensive time on the company's gas turbine simulator in Orlando where the trainees will have hands-on control experience well before the commercial operation of their facility back in Ghana.

Timetable specifics starting from start of barge construction in the first quarter 1996 include: delivery of the gas turbines to the shipyard in the second quarter 1996; ocean towing with power barges delivered to site in the fourth quarter 1996; and commercial operation in the first quarter of 1997.

Power in a hurry

Ghana's major power production is hydroelectric from the huge Volta River sources, but some of that capacity has been idled recently for extensive refurbishing of the hydro power equipment.

Out of the Volta River Authority's total installed capacity of around 1,100 MW, about 98% of this comes from the Akosombo Dam on the Volta in Eastern Ghana. The prolonged drought of 1994 dropped water levels behind the dam to critical levels for much of the year—threatening the shutdown of the generating plant.

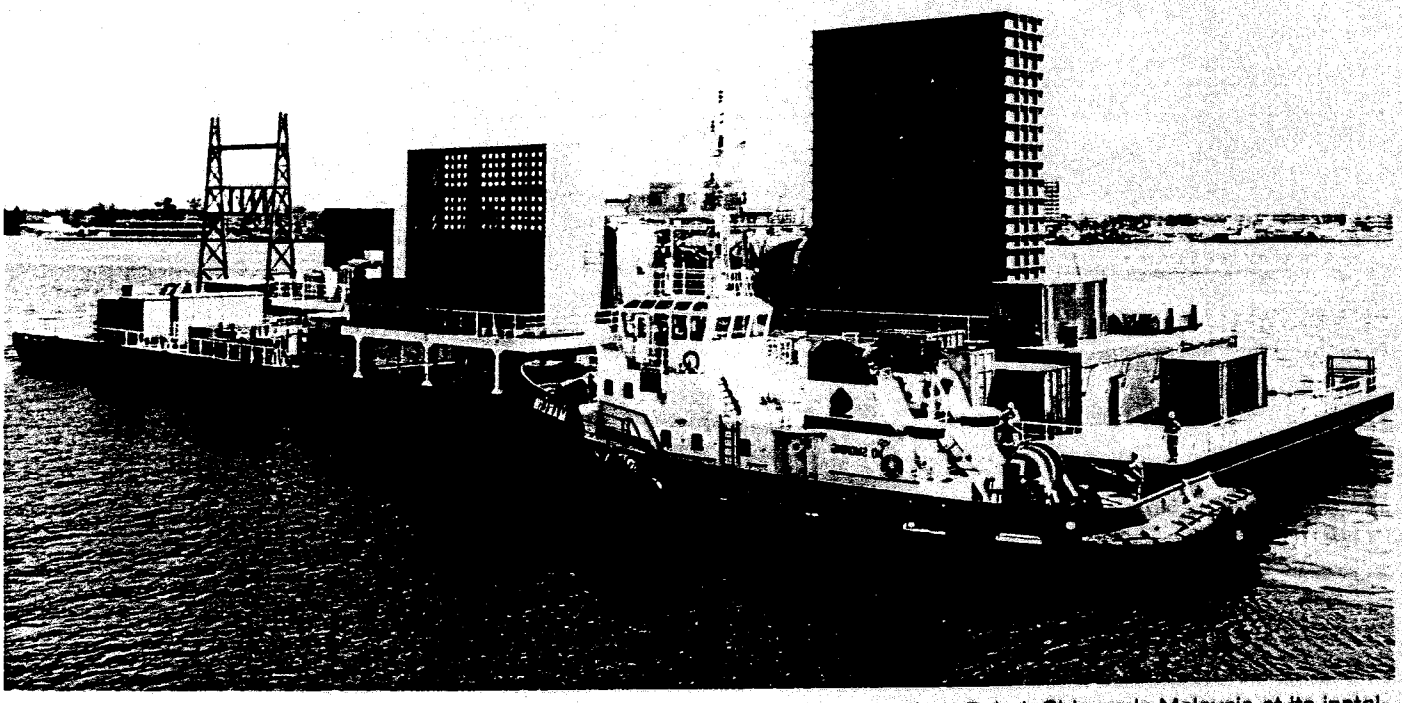
This situation alerted VRA to the need for power diversification into thermal plants. This capacity situation, coupled with the success of Ghana's Economic Recovery Program that was started in 1983, is boosting the country's economy and has resulted in a surge in electric power demand that cannot be met.

Electric power demand in Ghana is increasing about 15% per year. According to Tsatsu Tsikata, chief executive officer of GNPC, "Strong growth in demand is here now and is forecast in the future, associated with industrial growth and the continuation of programs of rural electrification.

"This has already led to a tight supply/demand balance at times of peak load. Ghana now has to import electricity to meet peak demand despite its historic role as net power exporter to neighboring countries. As a consequence, there is an urgent need for additional generation capacity in Ghana," he explains.

GNPC's plans call for simultaneous production of both oil and gas reserves in the Tano Field, originally discovered in the late 1970's but not developed because there was no market for gas according to the field operator at that time. GNPC intends to transport the gas via a 20-kilometer pipeline to the coastal barge-mounted power plant.

"Securing the power needs of the booming gold mining sector in Ghana is a specific objective of this project," Tsikata notes, "and the location, in the west of Ghana where most of the new mines are located is ideal for this. A secure, competitively priced power



Mooring Operation. Tugs prepare to moor 105-MW simple cycle power barge built at Sabah Shipyards Malaysia at its installation site in Manila in the Philippines following ocean transport.

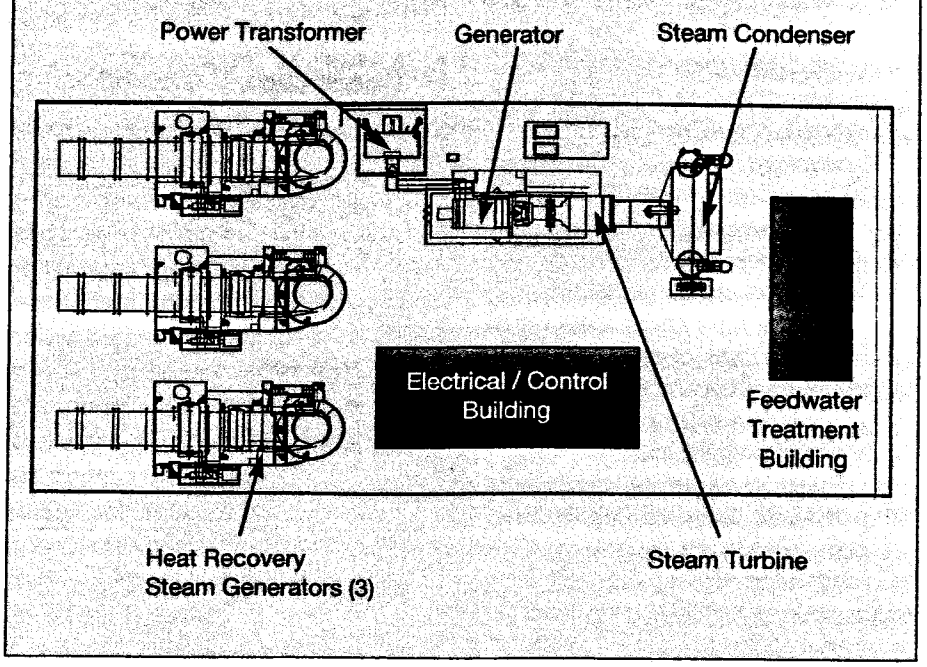
supply will promote more efficient and consequently profitable industrial operations," the chief executive stresses.

The project will also advance the government objective of connecting district capitals to the national grid network. "The per kW unit cost of power generated by this project is conservatively estimated to be half the cost of power generated from a greenfield oil-fired power station, due to the high cost of imported fuel here in Ghana.

"Futhermore, the utilization of indigenous natural gas resources will stimulate interest and investment in Ghana's oil and natural gas potential," he concludes.

And, as Westinghouse's Snyder explains it, "flexibility in siting is an important feature of the barge design. GNPC can relocate one or both of the power barges to different sites, thereby improving the economics of producing further offshore hydrocarbon reserves in the future."

Combined Cycle Barge. Plant can be expanded to combined cycle operation (Phase II) with the addition of this conversion barge. Will increase plant output to 200 MW from 131 MW (site ratings) at 47.7% efficiency (from 31.2% simple cycle). Barge is around 265 feet long and 145 feet wide.



Barge plant design

Since a barge deck can flex and/or bow from different atmospheric and water effects, the foundation for the power train requires special consideration because of the tight shaft alignment tolerances required with this type of power generation equipment.

The GNPC plant gas turbine generators and associated auxiliary equipment are mounted on isolation foundations that maintain the shaft alignment tolerances. Design principles are similar to those used for common 'three point' offshore platform power equipment installations.

All foundations and support structures are designed for the operational loads of the power plant. They are also designed for the transportation forces the barge and the structures will experience during the tow to site. (They will be using a "dry-tow" semisubmersible heavy-lift vessel to move the power barges over ocean to a deepwater location near the project site, then tugs will move them onto protected shoreside moorings.)

According to Lee Near, business development manager at Westinghouse, "the foundations are critical to maintaining the shaft alignment between the turbine, reduction gear and generator. The top of each foundation will be about 10 feet above the barge deck. Each foundation will support the gas turbine, gear box, generator, and starting package and is designed so that movement of the barge will not effect the alignment."

Other equipment located at the same level as the turbine generators includes the electrical package, lube oil cooler, and fuel gas skid. The foundations for both the inlet air filter and the exhaust stack are also extended to accommodate the power train elevation.

The fuel oil skid, hydraulic skid, firewater pumps, and emergency generator will be mounted directly on the barge deck. The crane pedestals are designed to support the maximum reactions from the crane in lifting a complete gas turbine rotor or generator rotor.

The pedestal will penetrate the barge deck and extend to the bottom of the barge with local reinforcing for strength. The electrical equipment is also mounted directly on the barge deck and includes the main transformers, switchgear, auxiliary equipment transformers, motor control centers/ switchgear.

The MCC/switchgear building is fabricated as a modular structure and then mounted on the deck of Barge number 1. This air-conditioned building measures 25 x 20 x 10 feet and contains the MCC, low-voltage switchgear, metering and relay panels, UPS, AC and DC distribution panel boards, lighting panel board, receptacle panel board and the battery room.

The building has a personnel door at the rear for emergency exit and a combination personnel/equipment door facing the bow. It is connected to the barge electrical, waste and air treatment system.

Offshore treatment

Even moored in a protected harbor, the gas turbines and auxiliaries have to be treated to handle the corrosive high salt atmosphere of the seacoast.

Compared to the standard inland-

based 251B Econopac, some specialized equipment, layout, design and materials are needed for barge mount.

To minimize salt-laden air from entering the turbine, the air inlet filter consists of a two-stage disposable pad type filter. A third stage demister pad is installed upstream of these two stages to protect filter elements from exposure to salt water spray. A trash screen is fitted ahead of the air inlet filter system.

The two-stage inlet air filter with de-mister is located over the generator approximately on the unit centerline and a top inlet air duct directs filtered air into the compressor inlet manifold. This arrangement is utilized in order to minimize barge layout space requirements.

Critical electrical equipment exposed to the environment are designed and built for the coastal environment in Ghana. For example, all use of aluminum components will be minimized and special attention will be given to overall power barge painting, including an ongoing painting program that will replace the entire paint system on a five-year interval. A rainwater collection system is specified for oily waste management.

The 215B compressor section airfoils and turbine blades will have protective coatings. All compressor stationary vanes will get Sermetel 5380 DP coating. First stage turbine section vanes get Chromalloy RT-75 which is an alloy base with thermal barrier coating. Row two vanes and rows one and two blades will have Sermalloy J coating. Westinghouse will apply a MCrAlY base and thermal barrier coating to selected areas of the transition pieces.

Philippines project kicks off Westinghouse barge plants

Westinghouse began its power barge program in 1993 in response to the growing demand for fast track solutions to power shortages in developing countries. The advantages of these floating plants are the initial cost and speed of construction, pre-commissioning or functional testing at the shipyard, mobility of the barge/plant and the ability to utilize it as a fixed asset that can be developed by private or public owners. Other advantages include modularity, ability to convert from simple cycle to combined cycle, reduced construction risk, and increased number of financing options.

According to Greg Snyder, who heads up the floating power plant projects, "The Philippines was the hot market in 1993 and Westinghouse got off to a good start by working with Sabah Shipyards in Labuan, Malaysia to mount the largest single gas turbine ever put on a vessel — the 501D rated 105 MW." This power barge has now been operating in Manila since October 1994, supplying power to the state-owned National Power Corporation (Napocor).

Barge plant designs are available for simple cycle and combined cycle units ranging from 48 MW up past 200 MW. Most of these designs are based on the model 251B11 gas turbine packaged power plant. As Snyder explains it, "The power barge market seems to have gravitated to smaller blocks of power — 50, 100 and 150 MWs —so the 251B11's 48 MW rating makes its a good building block for meeting power needs in a fast and flexible manner."

He notes the 251B's application flexibility comes from its geared generator drive that allows either 50 or 60 Hertz operation with the same gas turbine. Most developing countries, he notes, are in 50-Hz service areas. The gas turbine also has seen significant experience on a wide variety of fuels.

For all these power barge designs, Westinghouse has worked closely with several A&E firms including Gilbert/Commonwealth, Hudson Engineering (McDermott) and Raytheon Engineers and Constructors.

The Orlando firm is currently under contract with Sabah Shipyards for another 501D for simple cycle barge operation as well as a number of 251B11s for both simple cycle (a 48 MW project in Asia, for example) and combined cycle applications (a 288 MW in 2x2+1 configurations for Pakistan).

Simplified equipment design

An electrical and control package is located next to the turbine enclosure and contains equipment necessary for sequencing, control, and monitoring of the turbine, generator, and auxiliaries.

This package includes a Westinghouse Powerlogic II digital control system, motor control centers, generator protective relay panels, voltage regulator, fire protection control system, redundant air conditioners, batteries, and battery charger.

The batteries are in an isolated section of the package and are readily accessible from the outside. Diesel engine provide black start capability.

To keep the barge auxiliary systems as simple as possible, the generators are of the open air-cooled type, with end frame bearings, two pole revolving field, brushless exciter, mounted in an acoustic weather proof enclosure with an air filtration and silencing system.

All three electric generators are identical, being 51.3 MVA Brush Electrical open air-cooled, Model

GNPC Simple Cycle Plant Performance

Site conditions in southwestern Ghana average 26.4°C (79°F) ambient air temperature, 1013.2 mbar barometric pressure, and 93% relative humidity. ISO standard conditions are air temperature of 15°C (59°F), pressure 1013.0 mbar, RH 60%. Output and heat rate are calculated on natural gas fuel at the high voltage side of the 161 kV step-up transformers.

	Site Rating	ISO Rating
Gross plant electrical output	132,900 kW	144,000 kW
Total auxiliary power losses	1500 kW	1600 kW
Net plant electrical output	131,400 kW	142,400 kW
Net plant heat rate (LHV)	11,527 kJ/kWh 10,929 Btu/kWh	11,223 kJ/kWh 10,640 Btu/kWh
Thermal efficiency	31.2%	32.1%
Exhaust temperature	532°C	524°C
Exhaust mass flow	496 kg/sec	519 kg/sec
Fuel flow rate (gaseous)	9.6 kg/sec	10.2 kg/sec

BDAX 7-290ER units with static excitation.

Also, for simplicity, the turbine and generator lubricating oil system is common and uses three separate pumps and a single, two-fan, forced-draft, oil-to-air oil cooler. The three pumps are the main alternating current motor driven pump, the auxiliary alternating current motor driven pump, and the emergency direct current motor driven pump.

The use of an air cooled cooler keeps the barge auxiliary systems as simple as possible and avoids the need for an auxiliary water cooling system.

O&M services

Under an initial 12-year contract, Westinghouse will provide management services, direct the operation and routine maintenance and provide major combustion turbine maintenance for this power facility.

This contract will include a long-term combustion turbine parts and repair package as part of the total O&M Program. This "Parts and Repair" package is a 12-year program that begins during the pre-operational phase.

In order to optimize the performance of the three 251B11 combustion turbines, the parts and repair program is designed around a roll in/ roll out philosophy.

This philosophy requires that prior to a 251B11 combustion turbine being taken off line, Westinghouse will have the required parts, either new or refurbished, staged on site.

The unit will be opened, the existing parts will be removed, and the new or refurbished parts will be installed. This allows for very quick maintenance turn arounds and the immediate restart of the combustion turbine. The existing parts will then be shipped off site for repair/refurbishment in preparation for the next combustion turbine scheduled outage.

The Westinghouse maintenance program will call for a continual and periodic visual inspection of the power barge hull above and below water, both external and internal. The object of the inspection is to check the paint system and the hull steel.

The periodic inspection program will be two-phased, based on a general visual and a checklist approach. The interval between inspections is expected to be 2 months for the visual only, and 6 months for the more formalized checklist inspection.

Paint system maintenance will be done on a continuous local basis and on a paint system life cycle replacement basis. The need for both will be determined through the inspection program.

Hull steel repair or replacement is anticipated only on an exception basis such as damage to the hull due to accident. Repairs will take place on a criticality basis with immediate repair of major damage, and periodic repair of minor dents, bends, etc., as the maintenance efforts are reviewed.

The hull below water will be inspected visually from the deck during the periodic inspections discussed above. The hull 5-year inspections (to allow continuation of ABS classification) will be the primary source of external below-water review of the hull status.

This diver inspection of the hull will reveal the hull steel and cathodic protection anode status. Based on the findings, hull maintenance could be expected to range from no required action to an extreme of replacement of anodes and doubling of hull sections.

Future combined cycle

As mentioned, GNPC has plans to convert the power station at some point in the future to combined cycle operation to improve thermal efficiency and boost power output. This would entail adding a nominal 75 MW combined-cycle conversion power barge to the existing power equipment barges.

Conversion to combined cycle operation would involve ducting (both fixed and flexible) the gas turbine exhaust to a separate steam barge containing a HRSG, steam turbine and associated mechanical and electrical Balance of Plant (BOP). Mechanically it is intended that the two barges will be hinged to limit relative motion.

At Ghana plant site conditions, the combined cycle would increase plant overall capacity from 131 MW to 200 MW with no additional fuel requirements. Net plant heat rate LHV would drop to some 7550 kJ/kWh (7158 Btu/kWh) at site conditions—for a thermal efficiency boost from 31.2% simple cycle to 47.7% efficiency in combined cycle at site in base load. ■

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Appendix I: Financial Analysis Details

This appendix contains the key results pages developed by the financial analysis model for both the land based and barge mounted options and include:

- Economic/Financial Assumptions and Inputs
- Profit and Loss
- Balance Sheet
- Operating Cash Flows
- Construction Draw Schedule

SENELEC IPP PROJECT - FINANCIAL MODEL

Date: 1-Nov-99

LAND CASE

GENERAL

Construction Start Date:.....	01-Jan-99
Commercial Operations:.....	01-Jan-01
Construction Period (months).....	24
Project Life (years):.....	20
Cycle:.....	Combined
Net Plant Capacity (MW):.....	70.9
Steam Capacity (tonnes):.....	0
Hours of Operation:.....	7,884
Operating Availability:.....	90.0%
Exchange Rate (CFA / US$):.....	

POWER GENERATION

Net Plant Capacity (MW):.....	70.9
Total Annual Output (MWh/year).....	558,976
Net Power Available for Sale (MW):..	63.8
Fuel Consumption (10^12 Btu/yr):....	4.02
Fuel Price ($/MMBtu):.....	2.70
Heat Rate (Btu/kWh):.....	7,197
Diesel Oil Consumption (gallons):.....	0
Steam Output (tonnes/hour)	
High Pressure:.....	0
Intermediate Pressure:.....	0
Low Pressure:.....	0
Total Annual Steam Output (tons/h):..	0

REVENUE

Electricity Tariff ($/MWh):	Year 1
Customer 1:.....	62.47
Customer 2:.....	0.00
Customer 3:.....	0.00

Electricity Sale:	MWh / year	%
Customer 1:.....	558,976	100.0%
Customer 2:.....	0	0.0%
Customer 3:.....	0	0.0%

USES

Specialized Equipment	30,755,000	41.3%
Other Equipment	1,413,000	1.9%
Civil	1,272,000	1.7%
Mechanical	$2,617,000	3.5%
Electrical	$1,521,000	2.0%
Buildings & Structures	426,000	0.6%
Contractor's Soft & Miscellaneous Costs	$7,545,000	10.1%
Engineering & Plant Startup	2,751,000	3.7%
Subtotal - Contractor's Internal Cost	**$48,300,000**	64.9%
Barge	0	0.0%
Tow and Moor At Site	0	0.0%
Contractor's Price	**$48,300,000**	64.9%
Taxes & Duties	$2,415,000	3.2%
Development Fee	$4,000,000	5.4%
High Pressure to Gas Line to Site Boundary	$2,700,000	3.6%
Contingencies	$1,250,000	1.7%
Cool Water Intake Structure & Pipe	$750,000	1.0%
Electrical Sub Station	$1,700,000	2.3%
Financing Fees/Legal Costs:.....	$3,000,000	4.0%
Working Capital:.....	$0	0.0%
Debt Service Reserve Fund:.....	$4,612,850	6.2%
IDC:.....	$5,698,094	7.7%
TOTAL PROJECT COST:.....	**$74,425,944**	**100.0%**

RESULTS

Equity IRR	23.0%
Min DSCR	1.41
Avg. DSCR	1.91

DSRF FACTOR

# Months:	6
Factor:	50%

CAPEX

Factor+Duties	*105.00%*
$ per KW	*$1,050*

SOURCES

EQUITY	$22,336,551	30.0%
ECA DEBT	$52,089,393	70.0%
TOTAL	**$74,425,944**	**100.0%**

SENELEC IPP PROJECT - FINANCIAL MODEL

P&L

	Construction		Operation ——>													
REVENUE / YEAR	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
	0	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14
Electricity Capacity Factor:	0	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%
Total Electricity Available (MWh):	0	139,744	558,976	558,976	558,976	558,976	558,976	558,976	558,976	558,976	558,976	558,976	558,976	558,976	558,976	558,976
Total Electricity Sales (MWh):	0	139,744	558,976	558,976	558,976	558,976	558,976	558,976	558,976	558,976	558,976	558,976	558,976	558,976	558,976	558,976
Electricity Tariff Customer 1 ($/MWh):	0.0	62.5	62.5	61.7	61.0	60.2	59.5	58.7	57.8	57.1	56.3	55.6	54.8	54.1	45.7	45.7
Electricity Tariff Customer 2 ($/MWh):	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Electricity Tariff Customer 3 ($/MWh):	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Electricity Revenue Customer 1	$0	$8,729	$34,917	$34,499	$34,080	$33,672	$33,243	$32,824	$32,320	$31,907	$31,483	$31,064	$30,645	$30,228	$25,543	$25,543
Electricity Revenue Customer 2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Electricity Revenue Customer 3	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL REVENUE FROM SALES:	$0	$8,729	$34,917	$34,499	$34,080	$33,672	$33,243	$32,824	$32,320	$31,907	$31,483	$31,064	$30,645	$30,228	$25,543	$25,543
OPERATING COSTS																
Fixed Costs																
Personnel:	$0	$438	$1,750	$1,750	$1,750	$1,750	$1,750	$1,750	$1,750	$1,750	$1,750	$1,750	$1,750	$1,750	$1,750	$1,750
Overheads:																
Maintenance:	$0	$419	$1,677	$1,677	$1,677	$1,677	$1,677	$1,677	$1,677	$1,677	$1,677	$1,677	$1,677	$1,677	$1,677	$1,677
Total Fixed Costs:	$0	$857	$3,427	$3,427	$3,427	$3,427	$3,427	$3,427	$3,427	$3,427	$3,427	$3,427	$3,427	$3,427	$3,427	$3,427
Variable Costs																
Fuel																
Natural Gas ($/MWh):	$0	$2,715	$10,862	$10,862	$10,862	$10,862	$10,862	$10,862	$10,862	$10,862	$10,862	$10,862	$10,862	$10,862	$10,862	$10,862
Diesel Oil ($/MWh):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Fuel Cost:	$0	$2,715	$10,862	$10,862	$10,862	$10,862	$10,862	$10,862	$10,862	$10,862	$10,862	$10,862	$10,862	$10,862	$10,862	$10,862
OtherVariable Costs ($/MWh):	$0	$838	$3,354	$3,354	$3,354	$3,354	$3,354	$3,354	$3,354	$3,354	$3,354	$3,354	$3,354	$3,354	$3,354	$3,354
OPERATING COSTS:	$0	$4,411	$17,643	$17,643	$17,643	$17,643	$17,643	$17,643	$17,643	$17,643	$17,643	$17,643	$17,643	$17,643	$17,643	$17,643
OPERATING INCOME:	$0	$4,319	$17,275	$16,856	$16,437	$16,029	$15,600	$15,181	$14,677	$14,264	$13,840	$13,421	$13,003	$12,585	$7,900	$7,900
Less Depreciation:	$0	$0	$4,654	$4,654	$4,654	$4,654	$4,654	$4,654	$4,654	$4,654	$4,654	$4,654	$4,654	$4,654	$4,654	$4,654
Less Interest Expense:	$0	$93	$5,107	$4,688	$4,269	$3,861	$3,432	$3,013	$2,594	$2,181	$1,757	$1,338	$920	$502	$158	$158
Plus Interest Income:	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TAXABLE INCOME:	$0	$4,226	$7,514	$7,514	$7,514	$7,514	$7,514	$7,514	$7,429	$7,429	$7,429	$7,429	$7,429	$7,429	$3,088	$3,088
Tax Losses:	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Taxes																
Income Tax:	$0	$1,057	$1,878	$1,878	$1,878	$1,878	$1,878	$1,878	$1,857	$1,857	$1,857	$1,857	$1,857	$1,857	$772	$772
Social Contribution:	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
NET INCOME:	$0	$3,170	$5,635	$5,635	$5,635	$5,635	$5,635	$5,635	$5,572	$5,572	$5,572	$5,572	$5,572	$5,572	$2,316	$2,316

SENELEC IPP PROJECT - FINANCIAL MODEL

REVENUE / YEAR	2015	2016	2017	2018	2019	2020
	15	16	17	18	19	20
Electricity Capacity Factor:	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%
Total Electricity Available (MWh):	558,976	558,976	558,976	558,976	558,976	558,976
Total Electricity Sales (MWh):	558,976	558,976	558,976	558,976	558,976	558,976
Electricity Tariff Customer 1 ($/MWh):	45.7	45.7	45.7	45.7	45.7	49.8
Electricity Tariff Customer 2 ($/MWh):	0.0	0.0	0.0	0.0	0.0	0.0
Electricity Tariff Customer 3 ($/MWh):	0.0	0.0	0.0	0.0	0.0	0.0
Electricity Revenue Customer 1	$25,543	$25,543	$25,543	$25,543	$25,543	$27,813
Electricity Revenue Customer 2	$0	$0	$0	$0	$0	$0
Electricity Revenue Customer 3	$0	$0	$0	$0	$0	$0
TOTAL REVENUE FROM SALES:	$25,543	$25,543	$25,543	$25,543	$25,543	$27,813
OPERATING COSTS						
Fixed Costs						
Personnel:	$1,750	$1,750	$1,750	$1,750	$1,750	$1,750
Overheads:						
Maintenance:	$1,677	$1,677	$1,677	$1,677	$1,677	$1,677
Total Fixed Costs:	$3,427	$3,427	$3,427	$3,427	$3,427	$3,427
Variable Costs						
Fuel						
Natural Gas ($/MWh):	$10,862	$10,862	$10,862	$10,862	$10,862	$10,862
Diesel Oil ($/MWh):	$0	$0	$0	$0	$0	$0
Total Fuel Cost:	$10,862	$10,862	$10,862	$10,862	$10,862	$10,862
OtherVariable Costs ($/MWh):	$3,354	$3,354	$3,354	$3,354	$3,354	$3,354
OPERATING COSTS:	$17,643	$17,643	$17,643	$17,643	$17,643	$17,643
OPERATING INCOME:	$7,900	$7,900	$7,900	$7,900	$7,900	$10,170
Less Depreciation:	$4,854	$0	$0	$0	$0	$0
Less Interest Expense:	$158	$158	$158	$158	$158	$174
Plus Interest Income:	$0	$0	$0	$0	$0	$0
TAXABLE INCOME:	$3,088	$7,742	$7,742	$7,742	$7,742	$9,997
Tax Losses:	$0	$0	$0	$0	$0	$0
Taxes						
Income Tax:	$772	$1,936	$1,936	$1,936	$1,936	$2,499
Social Contribution:	$0	$0	$0	$0	$0	$0
NET INCOME:	$2,316	$5,807	$5,807	$5,807	$5,807	$7,498

SENELEC IPP PROJECT - FINANCIAL MODEL

BALANCE SHEET

	Construction		Operation →								
Year	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Assets											
Cash	$0	$3,170	$521	$1,043	$1,559	$2,085	$2,607	$3,128	$3,646	$4,171	$4,692
Debt Service Reserve Account	$0	$4,613	$4,405	$4,197	$3,994	$3,781	$3,573	$3,365	$3,160	$2,950	$2,742
Accounts Receivable	$0	$1,076	$4,305	$4,253	$4,202	$4,151	$4,098	$4,047	$3,985	$3,934	$3,881
Total Current Assets	$0	$8,859	$9,231	$9,493	$9,755	$10,018	$10,278	$10,540	$10,791	$11,054	$11,315
Gross Plant Assets	$56,540	$69,813	$69,813	$69,813	$69,813	$69,813	$69,813	$69,813	$69,813	$69,813	$69,813
Accum. Depreciation	$0	$0	($4,654)	($9,308)	($13,963)	($18,617)	($23,271)	($27,925)	($32,579)	($37,234)	($41,888)
Net Plant Assets	$56,540	$69,813	$65,159	$60,505	$55,850	$51,196	$46,542	$41,888	$37,234	$32,579	$27,925
Total Assets	$56,540	$78,672	$74,390	$69,998	$65,605	$61,214	$56,820	$52,428	$48,025	$43,633	$39,240
Liabilities											
Working Capital Facility	$0	$783	$3,130	$3,079	$3,027	$2,977	$2,924	$2,872	$2,810	$2,759	$2,707
Accounts Payable	$0	$294	$1,174	$1,174	$1,174	$1,174	$1,174	$1,174	$1,174	$1,174	$1,174
Long Term Debt	$38,794	$52,089	$47,749	$43,408	$39,067	$34,726	$30,385	$26,045	$21,704	$17,363	$13,022
Total Liabilities	$38,794	$53,166	$52,054	$47,661	$43,269	$38,878	$34,484	$30,092	$25,689	$21,297	$16,904
Equity											
Paid in Equity	$17,745	$22,337	$22,337	$22,337	$22,337	$22,337	$22,337	$22,337	$22,337	$22,337	$22,337
Retained Earnings	$0	$3,170	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Equity	$17,745	$25,506	$22,337	$22,337	$22,337	$22,337	$22,337	$22,337	$22,337	$22,337	$22,337
Total Liability and Equity	$56,540	$78,672	$74,390	$69,998	$65,605	$61,214	$56,820	$52,428	$48,025	$43,633	$39,240

SENELEC IPP PROJECT - FINANCIAL MODEL

Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Assets											
Cash	$5,213	$5,734	$8,374	$13,028	$17,682	$22,337	$22,337	$22,337	$22,337	$22,337	$0
Debt Service Reserve Account	$2,534	$2,326	$0	$0	$0	$0	$0	$0	$0	$0	$0
Accounts Receivable	$3,830	$3,778	$3,727	$3,149	$3,149	$3,149	$3,149	$3,149	$3,149	$3,149	$3,429
Total Current Assets	$11,577	$11,839	$12,101	$16,177	$20,831	$25,486	$25,486	$25,486	$25,486	$25,486	$3,429
Gross Plant Assets	$69,813	$69,813	$69,813	$69,813	$69,813	$69,813	$69,813	$69,813	$69,813	$69,813	$69,813
Accum. Depreciation	($46,542)	($51,196)	($55,850)	($60,505)	($65,159)	($69,813)	($69,813)	($69,813)	($69,813)	($69,813)	($69,813)
Net Plant Assets	$23,271	$18,617	$13,963	$9,308	$4,654	$0	$0	$0	$0	$0	$0
Total Assets	$34,848	$30,456	$26,063	$25,486	$25,486	$25,486	$25,486	$25,486	$25,486	$25,486	$3,429
Liabilities											
Working Capital Facility	$2,655	$2,604	$2,552	$1,975	$1,975	$1,975	$1,975	$1,975	$1,975	$1,975	$0
Accounts Payable	$1,174	$1,174	$1,174	$1,174	$1,174	$1,174	$1,174	$1,174	$1,174	$1,174	$1,174
Long Term Debt	$8,682	$4,341	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Liabilities	$12,511	$8,119	$3,727	$3,149	$3,149	$3,149	$3,149	$3,149	$3,149	$3,149	$1,174
Equity											
Paid in Equity	$22,337	$22,337	$22,337	$22,337	$22,337	$22,337	$22,337	$22,337	$22,337	$22,337	$22,337
Retained Earnings	$0	$0	$0	$0	$0	$0	($0)	($0)	$0	($0)	($20,082)
Total Equity	$22,337	$22,337	$22,337	$22,337	$22,337	$22,337	$22,337	$22,337	$22,337	$22,337	$2,255
Total Liability and Equity	$34,848	$30,456	$26,063	$25,486	$25,486	$25,486	$25,486	$25,486	$25,486	$25,486	$3,429

SENELEC IPP PROJECT

CASHFLOW ANALYSIS

	Construction		Startup / Operation ——>										
YEAR	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
OPERATING CASHFLOW													
+ Cashflow From Operations:	$0	$4,319	$17,275	$16,856	$16,437	$16,029	$15,600	$15,181	$14,677	$14,264	$13,840	$13,421	$13,003
Changes in Working Capital:	$0	($783)	($2,348)	$52	$52	$50	$53	$52	$62	$51	$52	$52	$52
- Income Tax:	$0	($1,057)	($1,878)	($1,878)	($1,878)	($1,878)	($1,878)	($1,878)	($1,857)	($1,857)	($1,857)	($1,857)	($1,857)
- Social Contribution:	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
- Custom Duties (Captilized):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total:	$0	$2,480	$13,048	$15,029	$14,611	$14,201	$13,775	$13,355	$12,882	$12,458	$12,035	$11,616	$11,197
INVESTING CASHFLOW													
- Capital Expenditures:	$56,540	$17,886	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Cashflow After OPCF & INVCF:	($56,540)	($15,406)	$13,048	$15,029	$14,611	$14,201	$13,775	$13,355	$12,882	$12,458	$12,035	$11,616	$11,197
FINANCING CASHFLOW													
Short & Long Term Debt - Borrowed Funds													
+ ECA													
Principal (US$):	$36,856	$9,535	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Cap. Interest:	$1,938	$3,760	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
+ Working Cap													
Flow	$0	$783	$2,348	($52)	($52)	($50)	($53)	($52)	($62)	($51)	($52)	($52)	($52)
Total:	$38,794	$14,078	$2,348	($52)	($52)	($50)	($53)	($52)	($62)	($51)	($52)	($52)	($52)
Short & Long Term Debt - Interest and Principal Payments													
- ECA													
Principal (US$):	$0	$0	$4,341	$4,341	$4,341	$4,341	$4,341	$4,341	$4,341	$4,341	$4,341	$4,341	$4,341
Interest:	$0	$0	$4,885	$4,469	$4,053	$3,648	$3,222	$2,806	$2,390	$1,980	$1,558	$1,143	$727
- Working Cap													
Interest	$0	$93	$222	$219	$216	$213	$210	$207	$204	$201	$198	$196	$193
Principal	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Short & Long Term Debt Service Payments:	$0	$93	$9,447	$9,029	$8,610	$8,202	$7,773	$7,354	$6,935	$6,522	$6,096	$5,679	$5,260
Net Financing Cashflow Before Equity:	$38,794	$13,985	($7,100)	($9,080)	($8,662)	($8,252)	($7,826)	($7,406)	($6,997)	($6,573)	($6,150)	($5,731)	($5,312)
Paid In Equity:	$17,745	$4,591	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Cumulative Paid in Equity:	$17,745	$22,337	$22,337	$22,337	$22,337	$22,337	$22,337	$22,337	$22,337	$22,337	$22,337	$22,337	$22,337
Debt Service Reserve Fund:	$0	$4,613	$4,405	$4,197	$3,994	$3,781	$3,573	$3,365	$3,160	$2,950	$2,742	$2,534	$2,326
Cash to (from) Debt Service Reserve Fund:	$0	$0	($208)	($208)	($203)	($213)	($208)	($208)	($205)	($211)	($206)	($208)	($207)
Cash Available for Debt Service:	$0	-	$13,048	$15,029	$14,611	$14,201	$13,775	$13,355	$12,882	$12,458	$12,035	$11,616	$11,197
Net Cashflow Available for Distribution:	($0)	$3,170	$6,157	$6,157	$6,152	$6,162	$6,157	$6,157	$6,090	$6,096	$6,093	$6,093	$6,092
IRR CALCULATION ======>	($17,745)	($4,591)	$8,805	$5,635	$5,635	$5,635	$5,635	$5,635	$5,572	$5,572	$5,572	$5,572	$5,572
Projected IRR:	23.0%												
Debt Service Coverage Ratio:	-		1.41	1.71	1.74	1.78	1.82	1.87	1.91	1.97	2.04	2.12	2.21

SENELEC IPP PROJECT

YEAR	2012	2013	2014	2015	2016	2017	2018	2019	2020
OPERATING CASHFLOW									
+ Cashflow From Operations:	$12,585	$7,900	$7,900	$7,900	$7,900	$7,900	$7,900	$7,900	$10,170
Changes in Working Capital:	$51	$578	$0	$0	$0	$0	$0	$0	($280)
- Income Tax:	($1,857)	($772)	($772)	($772)	($1,936)	($1,936)	($1,936)	($1,936)	($2,499)
- Social Contribution:	$0	$0	$0	$0	$0	$0	$0	$0	$0
- Custom Duties (Captilized):	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total:	$10,779	$7,706	$7,128	$7,128	$5,965	$5,965	$5,965	$5,965	$7,391
INVESTING CASHFLOW									
- Capital Expenditures:	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Cashflow After OPCF & INVCF:	$10,779	$7,706	$7,128	$7,128	$5,965	$5,965	$5,965	$5,965	$7,391
FINANCING CASHFLOW									
Short & Long Term Debt - Borrowed Funds									
+ ECA									
Principal (US$):	$0	$0	$0	$0	$0	$0	$0	$0	$0
Cap. Interest:	$0	$0	$0	$0	$0	$0	$0	$0	$0
+ Working Cap									
Flow	($51)	($578)	$0	$0	$0	$0	$0	$0	$280
Total:	($51)	($578)	$0	$0	$0	$0	$0	$0	$280
Short & Long Term Debt - Interest and Principal Payments									
- ECA									
Principal (US$):	$4,341	$0	$0	$0	$0	$0	$0	$0	$0
Interest:	$312	$0	$0	$0	$0	$0	$0	$0	$0
- Working Cap									
Interest	$190	$158	$158	$158	$158	$158	$158	$158	$174
Principal	$0	$0	$0	$0	$0	$0	$0	$0	$2,255
Total Short & Long Term Debt Service Payments:	$4,843	$158	$158	$158	$158	$158	$158	$158	$2,428
Net Financing Cashflow Before Equity:	($4,894)	($736)	($158)	($158)	($158)	($158)	($158)	($158)	($2,148)
Paid in Equity:	$0	$0	$0	$0	$0	$0	$0	$0	$0
Cumulative Paid in Equity:	$22,337	$22,337	$22,337	$22,337	$22,337	$22,337	$22,337	$22,337	$22,337
Debt Service Reserve Fund:	$0	$0	$0	$0	$0	$0	$0	$0	$0
Cash to (from) Debt Service Reserve Fund:	($2,328)	$0	$0	$0	$0	$0	$0	$0	$0
Cash Available for Debt Service:	$10,779	$7,706	$7,128	$7,128	$5,965	$5,965	$5,965	$5,965	$7,391
Net Cashflow Available for Distribution:	$8,212	$6,970	$6,970	$6,970	$5,807	$5,807	$5,807	$5,807	$5,243
IRR CALCULATION ========>	$5,572	$2,316	$2,316	$2,316	$5,807	$5,807	$5,807	$5,807	$27,580
Projected IRR:									
Debt Service Coverage Ratio:	2.32	-	-	-	-	-	-	-	-

Construction Draw Schedule

Date	Jan - Mar/ 99	Apr - Jun / 99	Jul - Sep / 99	Oct - Dec / 99	Jan - Mar/ 00	Apr - Jun / 00	Jul - Sep / 00	Oct - Dec / 00	Jan-01	Apr-01	Total	
Heat Recovery Steam Generator									$0	$0	$0	
Steam Turbine Genset									$0	$0	$0	
Fuel Handling									$0	$0	$0	
Mechanical & Electric Hardware									$0	$0	$0	
Spare Parts								$0	$0	$0	$0	
EPC Price	$ 7,003,500	$10,626,000	$12,558,000	$10,626,000	$2,898,000	$2,898,000	$1,690,500	$0	$0	$0	$48,300,000	
Other Equipment & Site Preparation									$0	$0	$0	
Taxes & Duties	$345,000	$345,000	$345,000	$345,000	$345,000	$345,000	$345,000				$2,415,000	
Engineering									$0	$0	$0	
Contingencies	$181,250	$275,000	$325,000	$275,000	$75,000	$75,000	$43,750	$0	$0	$0	$1,250,000	
Development Cost and Fee	$4,000,000								$0	$0	$4,000,000	
High Pressure Gas Line to Site	$391,500	$594,000	$702,000	$594,000	$162,000	$162,000	$94,500		$0	$0	$2,700,000	
Cooling Water Intake Structure and Pipe	$108,750	$165,000	$195,000	$165,000	$45,000	$45,000	$26,250		$0	$0	$750,000	
Electrical Substation and HT Lines	$246,500	$374,000	$442,000	$374,000	$102,000	$102,000	$59,500	$0	$0	$0	$1,700,000	
Financing Fees/Legal Costs	$3,000,000								$0	$0	$3,000,000	
Working Capital							$0	$0	$0	$0	$0	
Debt Service Reserve Fund							$4,612,850	$0	$0	$0	$4,612,850	
Total Const & Related Exp.:	$15,276,500	$12,379,000	$14,567,000	$12,379,000	$3,627,000	$3,627,000	$6,872,350	$0	$0	$0	$68,727,850	
Total Construction Drawdown:	22.23%	18.01%	21.20%	18.01%	5.28%	5.28%	10.00%	0.00%	0.00%	0.00%	100.00%	
EPC Drawdown	14.50%	22.00%	26.00%	22.00%	6.00%	6.00%	3.50%	0.00%	0.00%	0.00%	100.00%	
Interest During Construction:	$203,941	$377,428	$588,094	$768,960	$824,853	$890,315	$1,012,019	$1,032,484	$0		$5,698,094	
Total Project Cost:	$15,480,441	$12,756,428	$15,155,094	$13,147,960	$4,451,853	$4,517,315	$7,884,369	$1,032,484	$0	$0	$74,425,944	$74,425,944
	$0.145	$0.216	$0.255	$0.216	$0.064	$0.064	$0.040	$0.000	$0.000			

	0.675	10,311,638	8,355,825	9,832,725	8,355,825	2,448,225	2,448,225	4,638,836	-	-	-	46,391,299	
	0.325	4,964,863	4,023,175	4,734,275	4,023,175	1,178,775	1,178,775	2,233,514	-	-	-	22,336,551	
		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
	1.00	$203,941	$377,428	$588,094	$768,960	$824,853	$890,315	$1,012,019	$1,032,484	$0	$0	$5,698,094	
Totals		$10,515,579	$8,733,253	$10,420,819	$9,124,785	$3,273,078	$3,338,540	$5,650,855	$1,032,484	$0	$0	$52,089,393	70.0%
		$4,964,863	$4,023,175	$4,734,275	$4,023,175	$1,178,775	$1,178,775	$2,233,514	$0	$0	$0	$22,336,551	30.0%
		$38,794,435	$13,294,957									$74,425,944	
		$17,745,488	$4,591,064										

Specialized Equipment	28,000,000
Other Equipment	2,150,000
Civil	2,500,000
Mechanical	$0
Electrical	$0
Buildings & Structures	12,000,000
Contractor's Soft & Miscellaneous Costs	$0
Engineering & Plant Startup	6,065,000
Subtotal - Contractor's Internal Cost	$50,715,000
Barge	6,000,000
Tow and Moor At Site	1,500,000
Contractor's Price	$58,215,000
Financing Fees/Legal Costs:.....	$3,000,000
Development Fees	$4,400,000

SENELEC IPP PROJECT - FINANCIAL MODEL

Date: 08-Nov-99

BARGE CASE

GENERAL

Construction Start Date:.....	01-Jan-99
Commercial Operations:.....	01-Jan-01
Construction Period (months).....	24
Project Life (years):.....	20
Cycle:.....	Combined
Net Plant Capacity (MW):.....	67.3
Steam Capacity (tonnes):.....	0
Hours of Operation:.....	7,884
Operating Availability:.....	90.0%
Exchange Rate (CFA / US$):.....	

POWER GENERATION

Net Plant Capacity (MW):.....	67.3
Total Annual Output (MWh/year).....	530,593
Net Power Available for Sale (MW):..	60.6
Fuel Consumption (10^12 Btu/yr):....	3.81
Fuel Price ($/MMBtu):.....	2.70
Heat Rate (Btu/kWh):.....	7,175
Diesel Oil Consumption (gallons):.....	0
Steam Output (tonnes/hour)	
High Pressure:.....	0
Intermediate Pressure:.....	0
Low Pressure:.....	0
Total Annual Steam Output (tons/h):..	0

REVENUE

Electricity Tariff ($/MWh):	Year 1
Customer 1:.....	64.50
Customer 2:.....	0.00
Customer 3:.....	0.00

Electricity Sale:	MWh / year	%
Customer 1:.....	530,593	100.0%
Customer 2:.....	0	0.0%
Customer 3:.....	0	0.0%

USES

Specialized Equipment	28,000,000	35.7%
Other Equipment	2,150,000	2.7%
Civil	2,500,000	3.2%
Mechanical	$0	0.0%
Electrical	$0	0.0%
Buildings & Structures	12,000,000	15.3%
Contractor's Soft & Miscellaneous Costs	$0	0.0%
Engineering & Plant Startup	6,065,000	7.7%
Subtotal - Contractor's Internal Cost	**$50,715,000**	64.6%
Barge	6,000,000	7.6%
Tow and Moor At Site	1,500,000	1.9%
Contractor's Price	**$58,215,000**	74.1%
Taxes & Duties	$2,535,000	3.2%
Development Fee	$4,000,000	5.1%
Contingencies	$0	0.0%
Other 2	$0	0.0%
Financing Fees/Legal Costs:	$2,500,000	3.2%
Working Capital:	$0	0.0%
Debt Service Reserve Fund:	$4,874,496	6.2%
IDC:	$6,415,677	8.2%
TOTAL PROJECT COST:	$78,540,173	100%

RESULTS		
Equity IRR	23.0%	
Min DSCR	1.35	
Avg. DSCR	1.77	
DSRF FACTOR		
# Months:	6	
Factor:	50%	
CAPEX		
Factor+Duties	105.00%	
$ per KW	$1,167	
SOURCES		
Equity	$19,632,288	25%
ECA Debt	$58,907,885	75%
TOTAL	$78,540,173	100%

SENELEC IPP PROJECT - FINANCIAL MODEL **P & L** **BARGE CASE**

	Construction		Operation ---------->													
REVENUE / YEAR	**1999**	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**
	0	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14
Electricity Capacity Factor:	0	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%
Total Electricity Available (MWh):	0	132,648	530,593	530,593	530,593	530,593	530,593	530,593	530,593	530,593	530,593	530,593	530,593	530,593	530,593	530,593
Total Electricity Sales (MWh):	0	132,648	530,593	530,593	530,593	530,593	530,593	530,593	530,593	530,593	530,593	530,593	530,593	530,593	530,593	530,593
Electricity Tariff Customer 1 ($/MWh):	0.0	64.5	64.5	63.7	63.0	62.2	61.4	60.7	59.9	59.1	58.4	57.6	56.8	56.1	55.3	54.5
Electricity Tariff Customer 2 ($/MWh):	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Electricity Tariff Customer 3 ($/MWh):	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Electricity Revenue Customer 1	$0	$8,556	$34,224	$33,816	$33,413	$33,019	$32,601	$32,195	$31,781	$31,383	$30,970	$30,564	$30,158	$29,755	$29,346	$28,941
Electricity Revenue Customer 2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Electricity Revenue Customer 3	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL REVENUE FROM SALES:	$0	$8,556	$34,224	$33,816	$33,413	$33,019	$32,601	$32,195	$31,781	$31,383	$30,970	$30,564	$30,158	$29,755	$29,346	$28,941
OPERATING COSTS																
Fixed Costs																
Personnel:	$0	$500	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000
Overheads:																
Maintenance:		$431	$1,724	$1,724	$1,724	$1,724	$1,724	$1,724	$1,724	$1,724	$1,724	$1,724	$1,724	$1,724	$1,724	$1,724
Material:																
Fees:																
Insurance:																
Total Fixed Costs:	$0	$931	$3,724	$3,724	$3,724	$3,724	$3,724	$3,724	$3,724	$3,724	$3,724	$3,724	$3,724	$3,724	$3,724	$3,724
Variable Costs																
Fuel																
Natural Gas ($/MWh):	$0	$2,570	$10,279	$10,279	$10,279	$10,279	$10,279	$10,279	$10,279	$10,279	$10,279	$10,279	$10,279	$10,279	$10,279	$10,279
Diesel Oil ($/MWh):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Fuel Cost:	$0	$2,570	$10,279	$10,279	$10,279	$10,279	$10,279	$10,279	$10,279	$10,279	$10,279	$10,279	$10,279	$10,279	$10,279	$10,279
Water:																
Other Consumables:																
Waste Disposal:																
Emission Fees:																
Other Fees:																
OtherVariable Costs ($/MWh):	$0	$796	$3,184	$3,184	$3,184	$3,184	$3,184	$3,184	$3,184	$3,184	$3,184	$3,184	$3,184	$3,184	$3,184	$3,184
OPERATING COSTS:	$0	$4,297	$17,187	$17,187	$17,187	$17,187	$17,187	$17,187	$17,187	$17,187	$17,187	$17,187	$17,187	$17,187	$17,187	$17,187
OPERATING INCOME:	$0	$4,259	$17,037	$16,632	$16,226	$15,832	$15,414	$15,008	$14,594	$14,196	$13,783	$13,377	$12,971	$12,569	$12,159	$11,754
Less Depreciation:	$0	$0	$4,911	$4,911	$4,911	$4,911	$4,911	$4,911	$4,911	$4,911	$4,911	$4,911	$4,911	$4,911	$4,911	$4,911
Wotk. Cap Int. Expense			$215	$211	$208	$204	$201	$197	$194	$190	$187	$183	$180	$176	$173	$169
Less Interest Expense:	$0	$67	$5,540	$5,138	$4,736	$4,346	$3,931	$3,529	$3,126	$2,732	$2,322	$1,919	$1,517	$1,118	$713	$310
Plus Interest Income:	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TAXABLE INCOME:	$0	$4,172	$6,371	$8,371	$6,371	$6,371	$6,371	$6,371	$6,363	$6,363	$6,363	$6,363	$6,363	$6,363	$6,363	$6,363
Tax Losses:	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Taxes																
Income Tax:	$0	$1,043	$1,593	$1,593	$1,593	$1,593	$1,593	$1,593	$1,591	$1,591	$1,591	$1,591	$1,591	$1,591	$1,591	$1,591
Social Contribution:	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
NET INCOME:	$0	$3,129	$4,778	$4,778	$4,778	$4,778	$4,778	$4,778	$4,772	$4,772	$4,772	$4,772	$4,772	$4,772	$4,772	$4,772

SENELEC IPP PROJECT - FINANCIAL MODEL

REVENUE / YEAR	2015	2016	2017	2018	2019	2020
	15	16	17	18	19	20
Electricity Capacity Factor:	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%
Total Electricity Available (MWh):	530,593	530,593	530,593	530,593	530,593	530,593
Total Electricity Sales (MWh):	530,593	530,593	530,593	530,593	530,593	530,593
Electricity Tariff Customer 1 ($/MWh):	45.9	45.9	45.9	45.9	45.9	49.9
Electricity Tariff Customer 2 ($/MWh):	0.0	0.0	0.0	0.0	0.0	0.0
Electricity Tariff Customer 3 ($/MWh):	0.0	0.0	0.0	0.0	0.0	0.0
Electricity Revenue Customer 1	$24,360	$24,360	$24,360	$24,360	$24,360	$26,489
Electricity Revenue Customer 2	$0	$0	$0	$0	$0	$0
Electricity Revenue Customer 3	$0	$0	$0	$0	$0	$0
TOTAL REVENUE FROM SALES:	$24,360	$24,360	$24,360	$24,360	$24,360	$26,489
OPERATING COSTS						
Fixed Costs						
Personnel:	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000
Overheads:						
Maintenance:	$1,724	$1,724	$1,724	$1,724	$1,724	$1,724
Material:						
Fees:						
Insurance:						
Total Fixed Costs:	$3,724	$3,724	$3,724	$3,724	$3,724	$3,724
Variable Costs						
Fuel						
Natural Gas ($/MWh):	$10,279	$10,279	$10,279	$10,279	$10,279	$10,279
Diesel Oil ($/MWh):	$0	$0	$0	$0	$0	$0
Total Fuel Cost:	$10,279	$10,279	$10,279	$10,279	$10,279	$10,279
Water:						
Other Consumables:						
Waste Disposal:						
Emission Fees:						
Other Fees:						
OtherVariable Costs ($/MWh):	$3,184	$3,184	$3,184	$3,184	$3,184	$3,184
OPERATING COSTS:	$17,187	$17,187	$17,187	$17,187	$17,187	$17,187
OPERATING INCOME:	$7,173	$7,173	$7,173	$7,173	$7,173	$9,302
Less Depreciation:	$4,911	$0	$0	$0	$0	$0
Wotk. Cap Int. Expense	$130	$130	$130	$130	$130	$148
Less Interest Expense:	$17	$17	$17	$17	$17	$13
Plus Interest Income:	$0	$0	$0	$0	$0	$0
TAXABLE INCOME:	$2,115	$7,026	$7,026	$7,026	$7,026	$9,141
Tax Losses:	$0	$0	$0	$0	$0	$0
Taxes						
Income Tax:	$529	$1,757	$1,757	$1,757	$1,757	$2,285
Social Contribution:	$0	$0	$0	$0	$0	$0
NET INCOME:	$1,586	$5,270	$5,270	$5,270	$5,270	$6,856

SENELEC IPP PROJECT - FINANCIAL MODEL

BALANCE SHEET

	Construction		Operation ---------->								
Year	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Assets											
Cash	$0	$3,129	$905	$1,810	$2,709	$3,619	$4,524	$5,429	$6,330	$7,239	$8,144
Debt Service Reserve Account	$0	$4,874	$4,673	$4,471	$4,276	$4,068	$3,867	$3,665	$3,468	$3,262	$3,061
Accounts Receivable	$0	$1,055	$4,219	$4,169	$4,119	$4,071	$4,019	$3,969	$3,918	$3,869	$3,818
Total Current Assets	$0	$9,058	$9,797	$10,451	$11,104	$11,759	$12,410	$13,064	$13,716	$14,370	$15,023
Gross Plant Assets	$59,307	$73,666	$73,666	$73,666	$73,666	$73,668	$73,666	$73,666	$73,666	$73,666	$73,666
Accum. Depreciation	$0	$0	($4,911)	($9,822)	($14,733)	($19,644)	($24,555)	($29,466)	($34,377)	($39,288)	($44,199)
Net Plant Assets	$59,307	$73,666	$68,755	$63,844	$58,933	$54,021	$49,110	$44,199	$39,288	$34,377	$29,466
Total Assets	$59,307	$82,724	$78,552	$74,294	$70,036	$65,780	$61,521	$57,263	$53,004	$48,748	$44,489
Liabilities											
Working Capital Facility	$0	$767	$3,068	$3,018	$2,968	$2,920	$2,868	$2,818	$2,767	$2,718	$2,667
Accounts Payable	$0	$288	$1,151	$1,151	$1,151	$1,151	$1,151	$1,151	$1,151	$1,151	$1,151
Long Term Debt	$43,753	$58,908	$54,700	$50,492	$46,285	$42,077	$37,669	$33,662	$29,454	$25,246	$21,039
Total Liabilities	$43,753	$59,963	$58,920	$54,662	$50,404	$46,148	$41,889	$37,631	$33,372	$29,115	$24,857
Equity											
Paid in Equity	$15,554	$19,632	$19,632	$19,632	$19,632	$19,632	$19,632	$19,632	$19,632	$19,632	$19,632
Retained Earnings	$0	$3,129	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Equity	$15,554	$22,761	$19,632	$19,632	$19,632	$19,632	$19,632	$19,632	$19,632	$19,632	$19,632
Total Liability and Equity	$59,307	$82,724	$78,552	$74,294	$70,036	$65,780	$61,521	$57,263	$53,004	$48,748	$44,489
delta ----> $	-	-	-	-	-	-	-	-	-	-	-

SENELEC IPP PROJECT - FINANCIAL M

Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Assets											
Cash	$9,049	$9,952	$10,858	$11,763	$14,721	$19,632	$19,632	$19,632	$19,632	$19,632	$0
Debt Service Reserve Account	$2,859	$2,659	$2,456	$2,255	$0	$0	$0	$0	$0	($0)	$0
Accounts Receivable	$3,768	$3,718	$3,668	$3,618	$3,568	$3,003	$3,003	$3,003	$3,003	$3,003	$3,266
Total Current Assets	$15,676	$16,329	$16,983	$17,636	$18,289	$22,636	$22,636	$22,636	$22,636	$22,636	$3,266
Gross Plant Assets	$73,666	$73,666	$73,666	$73,666	$73,666	$73,666	$73,666	$73,666	$73,666	$73,666	$73,666
Accum. Depreciation	($49,110)	($54,021)	($58,933)	($63,844)	($68,755)	($73,666)	($73,666)	($73,666)	($73,666)	($73,666)	($73,666)
Net Plant Assets	$24,555	$19,644	$14,733	$9,822	$4,911	$0	$0	$0	$0	$0	$0
Total Assets	$40,231	$35,974	$31,716	$27,458	$23,200	$22,636	$22,636	$22,636	$22,636	$22,636	$3,266
Liabilities											
Working Capital Facility	$2,617	$2,567	$2,518	$2,467	$2,417	$1,852	$1,852	$1,852	$1,852	$1,852	$0
Accounts Payable	$1,151	$1,151	$1,151	$1,151	$1,151	$1,151	$1,151	$1,151	$1,151	$1,151	$1,151
Long Term Debt	$16,831	$12,623	$8,415	$4,208	$0	$0	$0	$0	$0	$0	$0
Total Liabilities	$20,599	$16,341	$12,084	$7,826	$3,568	$3,003	$3,003	$3,003	$3,003	$3,003	$1,151
Equity											
Paid In Equity	$19,632	$19,632	$19,632	$19,632	$19,632	$19,632	$19,632	$19,632	$19,632	$19,632	$19,632
Retained Earnings	$0	$0	$0	$0	$0	$0	$0	($0)	$0	$0	($17,517)
Total Equity	$19,632	$19,632	$19,632	$19,632	$19,632	$19,632	$19,632	$19,632	$19,632	$19,632	$2,115
Total Liability and Equity	$40,231	$35,974	$31,716	$27,458	$23,200	$22,636	$22,636	$22,636	$22,636	$22,636	$3,266
delta →	-	-	0	0	0	-	-	-	-	-	0

SENELEC IPP PROJECT

CASHFLOW ANALYSIS

	Construction		Startup / Operation ------->											
YEAR	**1999**	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**
OPERATING CASHFLOW														
+ Cashflow From Operations:	$0	$4,259	$17,037	$16,632	$16,226	$15,832	$15,414	$15,008	$14,594	$14,196	$13,783	$13,377	$12,971	$12,569
Changes in Working Capital:	$0	($767)	($2,301)	$50	$50	$49	$52	$50	$51	$49	$51	$50	$50	$50
- Income Tax:	$0	($1,043)	($1,593)	($1,593)	($1,593)	($1,593)	($1,593)	($1,593)	($1,591)	($1,591)	($1,591)	($1,591)	($1,591)	($1,591)
- Social Contribution:	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
- Custom Duties (Captilized):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total:	$0	$2,449	$13,143	$15,089	$14,683	$14,288	$13,873	$13,465	$13,055	$12,655	$12,243	$11,836	$11,430	$11,027
INVESTING CASHFLOW														
- Capital Expenditures:	59,307	19,233	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Cashflow After OPCF & INVCF:	($59,307)	($16,784)	$13,143	$15,089	$14,683	$14,288	$13,873	$13,465	$13,055	$12,655	$12,243	$11,836	$11,430	$11,027
FINANCING CASHFLOW														
Short & Long Term Debt - Borrowed Funds														
+ ECA														
Principal (US$):	$41,587	$10,906	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Cap. Interest:	$2,166	4,249	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
+ Multilateral Agency														
Principal (US$):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Cap. Interest:	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
+ Commercial Bank														
Principal (US$):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Cap. Interest:	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
+ Working Cap														
Flow	$0	$767	$2,301	($50)	($50)	($49)	($52)	($50)	($51)	($49)	($51)	($50)	($50)	($50)
Total:	$43,753	$15,922	$2,301	($50)	($50)	($49)	($52)	($50)	($51)	($49)	($51)	($50)	($50)	($50)
Short & Long Term Debt - Interest and Principal Payments														
- ECA														
Principal (US$):	$0	$0	$4,208	$4,206	$4,208	$4,208	$4,208	$4,206	$4,208	$4,208	$4,208	$4,208	$4,208	$4,208
Interest:	$0	$0	$5,541	$5,138	$4,735	$4,344	$3,929	$3,526	$3,123	$2,728	$2,317	$1,914	$1,511	$1,111
- Multilateral Agency														
Principal (US$):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Interest:	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
- Commercial Bank														
Principal (US$):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Interest:	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
- Working Capital														
Interest	$0	$87	$214	$211	$208	$206	$203	$200	$197	$195	$192	$189	$186	$183
Principal	$0	$0												
Total Short & Long Term Debt Service Payments:	$0	$87	$9,963	$9,557	$9,151	$8,758	$8,339	$7,934	$7,528	$7,130	$6,716	$6,310	$5,905	$5,502
Net Financing Cashflow Before Equity:	$43,753	$15,835	($7,861)	($9,607)	($9,201)	($8,806)	($8,391)	($7,984)	($7,579)	($7,179)	($6,767)	($6,360)	($5,955)	($5,552)
Paid in Equity:	$15,554	$4,079	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Cumulative Paid in Equity:	$15,554	$19,632	$19,632	$19,632	$19,632	$19,632	$19,632	$19,632	$19,632	$19,632	$19,632	$19,632	$19,632	$19,632
Debt Service Reserve Fund:	$0	$4,874	$4,673	$4,471	$4,276	$4,068	$3,867	$3,665	$3,468	$3,262	$3,061	$2,859	$2,659	$2,456
Cash to (from) Debt Service Reserve Fund:	$0	$0	($202)	($202)	($195)	($208)	($202)	($202)	($198)	($205)	($202)	($202)	($200)	($203)
Cash Available for Debt Service:	$0	$0	$13,143	$15,089	$14,683	$14,286	$13,873	$13,465	$13,055	$12,655	$12,243	$11,836	$11,430	$11,027
Net Cashflow Available for Distribution:	($0)	$3,129	$5,683	$5,683	$5,677	$5,689	$5,683	$5,683	$5,673	$5,681	$5,677	$5,677	$5,676	$5,679
IRR Calculation ======>	($15,554)	($4,079)	$7,908	$4,778	$4,778	$4,778	$4,778	$4,778	$4,772	$4,772	$4,772	$4,772	$4,772	$4,772
Projected IRR:	23.00%													
Debt Service Coverage Ratio:	-	-	1.35	1.61	1.64	1.67	1.70	1.74	1.78	1.82	1.88	1.93	2.00	2.07

SENELEC IPP PROJECT

YEAR	2013	2014	2015	2016	2017	2018	2019	2020
OPERATING CASHFLOW								
+ Cashflow From Operations:	$12,159	$11,754	$7,173	$7,173	$7,173	$7,173	$7,173	$9,302
Changes in Working Capital:	$50	$50	$565	$0	$0	$0	$0	($263)
- Income Tax:	($1,591)	($1,591)	($529)	($1,757)	($1,757)	($1,757)	($1,757)	($2,285)
- Social Contribution:	$0	$0	$0	$0	$0	$0	$0	$0
- Custom Duties (Capitilized):	$0	$0	$0	$0	$0	$0	$0	$0
Total:	$10,619	$10,213	$7,209	$5,416	$5,416	$5,416	$5,416	$6,755
INVESTING CASHFLOW								
- Capital Expenditures:	$0	$0	$0	$0	$0	$0	$0	$0
Net Cashflow After OPCF & INVCF:	$10,619	$10,213	$7,209	$5,416	$5,416	$5,416	$5,416	$6,755
FINANCING CASHFLOW								
Short & Long Term Debt - Borrowed Funds								
+ ECA								
Principal (US$):	$0	$0	$0	$0	$0	$0	$0	$0
Cap. Interest:	$0	$0	$0	$0	$0	$0	$0	$0
+ Multilateral Agency								
Principal (US$):	$0	$0	$0	$0	$0	$0	$0	$0
Cap. Interest:	$0	$0	$0	$0	$0	$0	$0	$0
+ Commercial Bank								
Principal (US$):	$0	$0	$0	$0	$0	$0	$0	$0
Cap. Interest:	$0	$0	$0	$0	$0	$0	$0	$0
+ Working Cap								
Flow	($50)	($50)	($565)	$0	$0	$0	$0	$263
Total:	($50)	($50)	($565)	$0	$0	$0	$0	$263
Short & Long Term Debt - Interest and Principal Payments								
- ECA								
Principal (US$):	$4,208	$4,208	$0	$0	$0	$0	$0	$0
Interest:	$705	$301	$0	$0	$0	$0	$0	$0
- Multilateral Agency								
Principal (US$):	$0	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Interest:	$0	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
- Commercial Bank								
Principal (US$):	$0	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Interest:	$0	$0	$0	$0	$0	$0	$0	$0
- Working Capital								
Interest	$181	$178	$147	$147	$147	$147	$147	$161
Principal								$2,115
Total Short & Long Term Debt Service Payments:	$5,093	$4,687	$147	$147	$147	$147	$147	$2,276
Net Financing Cashflow Before Equity:	($5,143)	($4,737)	($712)	($147)	($147)	($147)	($147)	($2,014)
Paid In Equity:	$0	$0	$0	$0	$0	$0	$0	$0
Cumulative Paid In Equity:	$19,632	$19,632	$19,632	$19,632	$19,632	$19,632	$19,632	$19,632
Debt Service Reserve Fund:	$2,255	$0	$0	$0	$0	$0	($0)	$0
Cash to (from) Debt Service Reserve Fund:	($202)	($2,255)	$0	$0	$0	$0	($0)	$0
Cash Available for Debt Service:	$10,619	$10,213	$7,209	$5,416	$5,416	$5,416	$5,416	$6,755
Net Cashflow Available for Distribution:	$5,677	$7,730	$6,497	$5,270	$5,270	$5,270	$5,270	$4,741
IRR Calculation ==========>	$4,772	$4,772	$1,586	$5,270	$5,270	$5,270	$5,270	$24,373
Projected IRR:								
Debt Service Coverage Ratio:	2.16	2.26	-	-	-	-	-	-