Office of Utilities Regulation

Generation Expansion Plan

2004 - 2012

Decision and Recommendations

to

Minister of Commerce, Science & Technology

OFFICE OF UTILITIES REGULATION

May 31, 2004

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1.0 INTRODUCTION

Before setting out the details of this decision, it is important that the legal/policy framework which underpins the Office's mandate be restated.

The OUR Act, Clause 4 (2) provides as follows –

> "The Office may, where it considers necessary, give directions to any licensee or specified organization with a view to ensuring that -
>
> (a) the needs of consumers of the services provided by the licensee or specified organization are met; and
>
> (b) the prescribed utility service operates efficiently and in a manner designed to –
>
> (i) protect the health and well being of users of the service and such elements of the public as would normally be expected to be affected by its operation; and
>
> (ii) protect and preserve the environment; and
>
> (iii) afford to its consumers economical and reliable service.

The OUR Act Clause 4 (3) also provides a duty on the Office in the performance of its functions to undertake such measures as it considers necessary or desirable to –

> (a) encourage competition in the provision of prescribed utility services;
>
> (b) protect the interests of consumers in relation to the supply of a prescribed utility service;

(c) encourage the development and use of indigenous resources;

(d) promote and encourage the development of modern and efficient utility services; and

(e) enquire into the nature and extent of the prescribed utility services provided by a licensee or specified organization.

The All-Island Electric License 2001 Condition 21 (2) (a), (b) states-

> “The Licensee shall submit the Least Cost Expansion Plan referred to in paragraph 1 to the Office for review. The Office, when satisfied that the Plan represents the least costs for system expansion consistent with internationally accepted best practice, will recommend the Plan to the Minister for his approval. On receipt of the recommendation from the Office, the Minister shall:
>
> (a) approve the Plan; or
>
> (b) refer the recommendation back to the Office for further consideration.

The License actually foresees two dimensions to the planning process. Firstly, the company is required to submit the planning procedures to the Office for approval. These procedures establish the high level framework to inform the development of the plan. Secondly, once the Office is satisfied that the Plan itself represents the least economic costs for system expansion, consistent with internationally accepted best industry practice, it is obliged to submit such Plan to the Minister.

All other things being equal, the Office would consider its primary duty as that of securing for customers and consumers, reliable electricity services at the lowest cost in a manner best designed to protect the environment.

2.0 DECISION

Demand Forecast

The Office is of the view that while it considers that the forecasted growth rate of 3.5% may appear conservative, there is no reason to question the forecasting methodology utilized by JPS as this has produced reasonably reliable results in the past.

The Office therefore accepts the 3.5% demand forecast recommended by JPS.

Reserve Margin

The Office has no reason to change the policy relating to the reliability standard and reconfirms the established reliability criteria of a loss of load probability of 0.55%. This translates to a reserve margin of 25%.

Capacity Additions

Based on the Demand forecast and the reliability standard, the Office supports the following schedule for Capacity Additions (the year shown indicates the full in-service year).

2006	**2008**	**2011**	**TOTAL**
40 MW	120 MW	120 MW	280 MW

If coal is the fuel technology chosen it may be necessary to commission an interim 40 MW in 2007. This will be largely dependent on the timeliness of the decision making in terms of the technology to be introduced.

Technology Options

As indicated earlier, the choice of technology will be dependent on the conclusions of the feasibility studies being conducted by the

Government with regard to the use of LNG in Jamaica. Conclusions in regard to this study are critically needed if the opportunity to influence a downward trend in electricity costs is not to be compromised.

In order to provide some basis for comparison, the Office will be initiating more definitive studies to evaluate the coal option.

The following are firm positions of the Office in relation to the technology options relating to the capacity additions:

1) Capacity additions in 2008 and 2011 must be base load plant, operating at capacity factors 80% and higher.

2) Technology options for this capacity must utilize LNG or coal (or some like fuel).

3) Fuel oil for electricity generation is not an option for Jamaica, going forward.

Renewable/Alternate Energy

In order to comply with the expected policy direction of the Government regarding Renewable Energy, the following objectives for energy supply utilizing renewable and alternate energy sources have been established:

	Total		
Year	**System Capacity (MW)**	**Energy (GWhrs)**	**Contribution from Renewables (GWhrs)**
2006	846	4097.8	245.9
2011	1046	4702.3	282.2

It should be noted that the introduction of Renewable technologies that do not offer firm capacity will not affect the objectives of the expansion plan but could add to the cost of displaced off peak capacity.

3.0 BACKGROUND

The first Least Cost Plan to be recommended under the terms of the All-Island Electric License 2001 was submitted to the Minster on 11 September 2001.

The circumstances and considerations that informed the September 2001 Plan are well documented, but it is important background to the current process to be reminded that in order to alleviate the effects of a catastrophic shortfall in capacity, JPS was forced in 2001 to –

(a) install a 20 MW gas turbine at Bogue on an emergency basis, with the agreement of the Office;

(b) prepare and submit a generation expansion plan to meet the short term needs for the period 2001 – 2004, which in addition to the 20 MW gas turbine referred to at (a) above proposed the installation of a 120 MW combined cycle gas turbine (CCGT) at Bogue.

The Plan referred to at (b) is that which the Office submitted to the Minister on September 11, 2001 and for which approval was eventually granted. The capacity additions referred to have been implemented.

In its decision, the Office recognized that, if the demand continued to grow at the traditional 5% - 6% per annum, the required reserve margin would be threatened by year-end 2005 and it therefore required the company to submit another Plan to address the longer term within 12 months.

The Office received the first submission in response to this requirement on September 27, 2002. While the review of this submission was in progress, the Office became aware of a policy direction of the Government in an initiative towards fuel diversity, in that it had decided to investigate the feasibility of introducing Liquefied Natural Gas (LNG) as a primary fuel in Jamaica. The implications of this policy, would clearly impact on the development of any generation expansion plan for Jamaica, going forward. The Office was concerned, though, that the necessary feasibility studies, the contractual arrangements that would have to be concluded and the implementation of the physical works to deliver LNG to the power station gates would not be completed in time to enable JPS to meet system demand by late 2005/early 2006. This concern was expressed to the Minister by letter dated January 28, 2003 when the Office urged that a decision be taken by June/July 2003. In its initial response to JPS, the Office recognized the uncertainty posed to the planning process in light of the policy initiative being taken and advised the company to proceed as though the LNG was <u>not</u> an option.

Since then the company presented two iterations of its proposed Least Cost Plan to the Office, the last of which is dated February 2004.

In regard to the Government's thrust for fuel diversification – the Office considers that of the available fuels, Liquid Natural Gas is the fuel of choice. It is the most environmentally friendly fuel currently available and when used with combined cycle gas turbine technology, offers the most efficient conversion to electric energy. The Office therefore supports the Government's policy initiative to introduce LNG, if it proves feasible, as the fuel of choice for the future. The Office cautions, however, that Jamaica's competitiveness in the global market place is influenced by electricity costs and that the introduction of LNG should therefore result in real benefits to consumers and the economy through reduction in the real cost of electricity.

The negotiated price of LNG and its stability through long term contracts is therefore critical but the Office believes that the benefits that may accrue from a change to LNG is such that it is worth allowing the time for the feasibility study to be concluded. Time, however, is of the essence and it is important that the feasibility of LNG be available by mid 2004 if the benefits are to be maximized.

Despite the initiative being taken in respect of LNG, however, there are other fuels and technologies (e.g. coal) which are proven and based on current prices are real alternatives to LNG.

Regardless of the fuel option chosen, it is critical if real benefits are to accrue to consumers that the decision is taken in such time as to maximize on the capacity that utilizes the new fuel in base load plant.

It is against this background that the decisions regarding the expansion plan are underpinned and form the basis for the recommendations to the Minister.

4.0 JAMAICA PUBLIC SERVICE COMPANY'S PROPOSAL

The information in this section summarizes the proposals made by JPS.

The most recent version of the Least Cost Generation Expansion Plan was submitted by JPS on February 16, 2004. The proposal is attached as Appendix 1. The capacity requirements have been established through a least cost expansion plan using the following basic assumptions.

Demand Projections

Peak Demand (MW) - 3.5%

Energy (MWh) - 3.5%

The Company proffers that the outturn of the last three years has seen a reduction of the traditional annual growth in demand from 5% to 1.3% in 2003. Up to 2002 the company was forecasting 4.5% annual growth in demand but it has suggested that there will be continued dampening in demand due to:

1. less than forecast economic growth
2. success in loss reduction efforts

Table 2
JPS Average Compounded Growth Rate

	10 Years 1992 - 2002	Last 5 Years 1997-2002	2001	2002	003	Avg. last 3 years	Forecast
Peak Demand	5.1%	4.4%	1.5%	4.8%	1.3%	2.5%	3.5%
Energy	5.1%	5.0%	1.8%	4.9%	4.9%	3.9%	3.5%

The company has forecasted 3.5% growth rate in demand and energy for the planning period 2003-2012.

Table 3
JPS - Demand Forecast

Year	Net Peak Demand (MW)	Energy (GWH)
2003	571.3	3696.0
2004	591.3	3825.4
2005	612.0	3959.2
2006	633.4	4097.8
2007	655.6	4241.2
2008	678.6	4389.7
2009	702.3	4543.3
2010	726.9	4702.3
2011	752.3	4866.9
2012	778.7	5037.3

The JPS Demand Forecast is attached as Appendix 2.

Reliability of Supply

For the purposes of system expansion planning, the company has used the agreed reliability criteria of a loss of load probability of 0.55% (equivalent to 48 hours per year). This means that there should be sufficient generation capacity available so as to allow the company to meet the forecast demand from electricity with its two largest units off the grid. This translates to a minimum reserve margin of 25%.

Capacity Needs

Based on the demand forecast and the reliability criteria the company has established the following capacity reserve profile (Table 4).

Table 4
JPS – Capacity Needs

Year	Gross Demand (MW)	Pre-Expansion Gross Capacity	Reserve
2003	589	766	30%
2004	609	766	26%
2005	631	766	21%
2006	653	766	17%
2007	675	766	13%
2008	699	766	9%
2009	724	766	6%
2010	749	766	2%
2011	775	766	-1%
2012	802	766	-5%

From Table 4, the company suggests that the reserve margin will be threatened as of 2005 when it will have fallen to 21%.

Government's Fuel Strategy

The company has recognized the critical importance placed by the Government on its initiative to diversify the country's fuel mix, but it suggests that, in order to facilitate diversity, it will be necessary for the cost of infrastructure to be normalized over a sufficiently long period of time so as to avoid the shock to one project.

It suggests that in the final analysis the Government may be required to take the lead in encouraging a partnership with fuel suppliers to facilitate the infrastructure development.

JPS indicates that the findings of the study to determine the feasibility of LNG will be completed within six (6) months of February 2004 and that the output of this study will be critical to the strategy that is ultimately implemented.

JPS' Recommendations

The company has proposed two expansion profiles to satisfy the projected demand. One based on the adoption of LNG (should this prove feasible), and the other proposing a solid fuel based expansion plan. It has done so recognizing that the decision on the feasibility of LNG will probably not be available until August/September 2004 which will in any event be too late to introduce a solution to meet the demand in 2005/2006. This, the company suggests introduces a constraint where an intermediate or stop-gap measure will have to be taken to satisfy the forecasted system demand at the end of 2005. The company therefore recommends the following:

1. Interim Stop-Gap Plan

   Install 40 MW by mid to end 2005 to ensure continued reliability of service. This will also –

   (i) allow the Government an opportunity to conclude its LNG feasibility study in the expected six months and facilitate the next tranche of capacity by 2007; and

   (ii) afford the Regulator an opportunity to put the framework in place to allow the next tranche to be implemented under the competitive model.

2. Base load expansion up to 2012.

The company recommends two options –

(i) Option 1

If the requirement to land gas in Jamaica at $3.90/mBTU (maximum) can be met then a gas-based expansion plan utilizing combined cycle technology would be the economic choice. The company suggests that even if the development of the required gas infrastructure could not meet the 2007 timeline for the first tranche of base load capacity expansion, combined cycle technology operating for up to 5 years on ADO, then converting to gas would still be the competitive option.

(ii) Option 2

If the gas strategy is not feasible, then a solid fuel based expansion plan is the recommended option. The company suggests that the benchmark technology under this scenario would be coal fired steam generating technology. Under this scenario 40 MW stop-gap capacity would probably have to be added in 2006/2007.

The company cautions that under both strategies the Government and the Regulator would have to provide a clear philosophy on the treatment of the initial infrastructure cost to facilitate the introduction of the new fuel sources.

5.0 DISCUSSION

The primary objectives of the Office in considering expansion plans for electricity supply are (1) security of supply, and (2) least prices to consumers.

A timely process of decision-making should secure the first objective, whilst rigorous development of the least cost expansion planning process as well as efficient management of the procurement of new capacity should secure the second.

In addressing the current plan the Office is mindful that the environment of the generation sub-sector is changing where, with effect from April 1, 2004, the generation market nominally became a competitive one.

The All-Island Electric Licence 2001, Condition 4 (a) describes the electricity generation market as follows:

> "In the first three years from the effective dated of this License, the Licensee shall have the exclusive right to develop new capacity. Upon the expiry of this period the Licensee shall have the together with other outside person(s) to compete for the right to develop new generation capacity."

Condition (18) sets out the basic framework under which the competition for new generation should be implemented.

The initiatives that are being taken by the Office to secure the competitive environment is the subject of another decision. Suffice it to say, that the basic output of the planning process should simply identify the quantum of, timing for and siting of the addition of new capacity. The thesis is that, in general terms, if the new capacity is acquired through a competitive process, the least cost solution would be the result.

Notwithstanding the expectations that would arise from competition, the Office is of the view, that it would be prudent to establish the least cost solution, based on the traditional least cost expansion planning techniques, if for no other reason but to serve as a benchmark against which to compare the outcome of the competitive process, or to specify the technology as a further dimension to the criteria mentioned above.

A number of important issues that inform the decision process are discussed below:

Expansion Planning Process

For the purposes of the current exercise, in conformity with Condition 21 of the License, the Office accepted the Long Term Planning Procedures on September 30, 2003. These procedures set out the criteria and high level planning standards that will inform the development of the Least Cost Expansion Plan. These procedures are available from the OUR's Information Centre.

Demand Forecast

The Office has intuitive concerns regarding the adoption of a 3.5% growth rate for demand. It is mindful however that an optimistic forecast would result in over investment which would ultimately impact on tariffs. A conservative forecast, however, would threaten reliability of supply through an erosion of the reserve margin and could result in decisions being taken to add new capacity at other than the economic choice.

The demand over the period 1997 – 2003 has been as follows:

Table 5
JPS – Historic Growth Rate

Year	Demand (Gross) (MW)	Growth MW	Rate %
1996	431	-	-
1997	468	37	8.6
1998	489	21	4.5
1999	521	32	6.5
2000	546	25	4.8
2001	555	9	1.6
2002	581	26	4.7
2003	589	8	1.3

In responding to concerns raised by the Office on the adoption of a 3.5% growth rate, the company has attributed the depression in the rate of growth in recent years from the traditional 5% - 6% to less than 3% to –

- significant reliability problems
- domestic economic problems
- fall-out in the US economy in the post September 11, 2001 environment

and has suggested that demand will continue to be dampened by –

1. less than forecast economic growth
2. success in its loss reduction efforts

and that the 2003 outturn confirms its expectation for a continued dampening in demand.

The arguments put forward by the company are persuasive, but the impact of the recently announced major developments on the island's north coast, for example, will have to be closely monitored as this could impact significantly on the forecast.

Fuel Diversity and Fuel

The Office is mindful of the Government's policy on fuel diversity and the current thrust towards the adoption of (LNG) as a primary fuel in Jamaica, if feasible. It is also aware that the ongoing feasibility study is expected to be concluded in July/August 2004 and that the objective is to land gas in Jamaica by late 2007.

The Office shares the concern expressed by JPS that critical to the success of any scheme to introduce fuel diversity will be the treatment of the initial infrastructure costs. In the case of LNG it will have to be assumed that the price of the fuel is that which would obtain with the fuel delivered to the power station gate. If coal or any other solid fuel such as Orimulsion were adopted, consideration would have to be given to the appropriate methodology to normalize the cost of the infrastructure over the long term rather than on the initial development.

The solid fuel option does offer some additional flexibility over LNG (as far as power generation is concerned) for the retrofitting existing plant to utilize the fuel.

The completion of the LNG study and the consequential policy positions taken by the Government and the Office is crucial. A final position, therefore, on the implementation of the long term solutions cannot therefore be concluded until that study is completed.

Fuel currently represents almost 50% of JPS' total operating costs. Through the fuel clause, the cost of fuel is a direct pass-through to the customer. Lowering the cost of fuel is therefore the primary and most effective approach to reducing the price of electricity to the consumer. This reduction in fuel cost can be realized through –

1) Appropriate decisions relating to capacity expansion in ensuring that the least cost solution is adopted, and

2) Effective fuel management and economic dispatch of operational plant.

The extent to which (1) above can be achieved is reflected in decisions on the expansion plan which recognize fuel diversity as an indispensable element to promoting cost competitiveness in electricity supply. In this regard the current Plan concludes that the primary realistically feasible fuel options are gas, solid fuels (Coal and Petcoke) and Orimulsion.

The realization of (2) above is attained through commitment on the part of the company to deliver service to its customers at the lowest price, and appropriate incentives through the regulatory framework to impel the company towards achieving greater efficiencies.

Proposed Capacity Needs

With the growth in demand projected at 3.5% per annum the company has proposed two possible scenarios. One option is based on a gas plan, the other on a solid fuel plan.

The comparative data for both plans is provided at Table 6, noting that the gas plan calls for capacity additions totaling 280 MW while the solid fuel plan could add 320 MW over the planning period. The corresponding capital investment is $260M and $470M respectively.

Table 6
Electric Power System Expansion Options

GAS PLAN						SOLID FUEL PLAN			
Year	Demand (MW)	Avail Cap. (MW)	Cap. Add'n (MW)	Total Cap. (MW)	Reserve Margin	Ave. Cap. (MW)	Cap. Add'n (MW)	Total Cap. (MW)	Reserve Margin (MW)
2003	589	766	-	-	30	766	-	766	30
2004	609	766	-	766	26	766	-	766	26
2005	631	766	40	806	28	766	40	806	28
2006	653	806	40	846	30	806	40	846	30
2007	675	846	80	926	37	846	-	846	25
2008	699	926	-	926	37	846	120	966	72
2009	724	926	40	966	33	966	-	966	33
2010	749	966	80	1046	40	966		966	29
2011	775	1046	-	1046	34	966	120	1086	40
2012	802	1046	-	1046	30	1086	-	1086	35
Total Add'l Capacity			**280**				**320**		

Screening Analysis/Life Cycle Costs

While there seems to be an inconsistency in the conclusions drawn by JPS from the Screening analysis and Lifecycle Cost comparisons, in terms of the technology choices, the Lifecycle cost comparisons suggest that of the technology options, at capacity factors 70% and over, Petcoke would appear to be the technology of choice.

The company however has not considered Petcoke as a technology option in the screening analysis.

What the screening analysis presents, however, are the options (excluding Petcoke) for technologies choices that have to be implemented within specific time horizons. These are important, as the demand projections suggest that incremental capacity will be required as early as 2005, if the reserve margin criteria are to be met.

It is out of this screening analysis and the carrying out of detailed WASP simulations that the company has developed the two scenarios set out in the Plan.

While the Office appreciates that the traditional approaches to least cost planning may result in considerations that may render the decision or recommendations to be moot, as the competitive process ought to result in the least cost solution, particularly if technology options are fixed, it is of the view that the competition may not, in itself produce the least cost solution. This is possible because it is conceivable that investors may not offer the high capital costs solutions that would be associated with genuine base load options but may offer solutions that reflect the lower capital cost technologies which are generally classified as intermediate plant. In these circumstances customers would not see the benefit of any real reduction in electricity costs as the solutions adopted would not necessarily be optimal.

If the life cycle cost comparisons are to be considered the candidate technologies for base load plant (i.e. plant operating at least 75% capacity factor) would have to include coal fired steam, combined cycle, using LNG and Petcoke.

The company from the screening analysis suggests that the candidate technologies would be coal and combined cycle using LNG (on the presumption that LNG can be landed at less than $3.9 per mBTu) at the power station gate.

6.0 CONCLUSIONS

The Office has formed its decisions based on the following conclusions.

Demand Forecast

The projection for a 3.5% growth in demand is consistent with other trends being experienced in the economy. There may be opportunities for JPS to add spot loads, as consumers which are currently self-generators may contract for JPS supply, with improving reliability and if the price of energy becomes competitive. The implications for the tariff or conversely for security of supply are significant issues as an optimistic forecast could lead to over investment which would tend to trend tariffs upward while a conservative forecast would threaten the reserve margin and thus security of supply. There are signals that there may be growth in certain areas of the economy which may have an impact on electricity demand. This situation will have to be closely monitored.

Capacity Additions

If a real decrease in the retail cost of electricity is to be achieved, base load plant must be added to the system. The practice of adding intermediate plant to meet incremental increase in demand must be reversed and to this end capacity additions must be structured in such a manner as to provide the opportunity for the maximum possible capacity using “base load technology” that can be added economically to be realized.

In previous reviews of expansion plans the Office has commented that selecting options for the purpose of satisfying only incremental increases in demand over relatively short periods is unlikely to result in the most economic overall generation mix. Given the relatively long lead time between the decision to proceed and the commissioning of a major generating unit, in the conventional approach, technology selection should be firmed up based on the best available information and in time to permit commercial operation before system reliability becomes jeopardized.

Similarly, a sufficiently long lead time will be required to facilitate the preparation of offers for a competition for base load plant.

Table 7 provides a high level breakdown of the expected system costs based on the coal plan and gas plan assuming the introduction of 40MW diesel capacity 2005/2006.

The analysis assumes current known market rates for the fuels involved (coal at $4.00/mBTu and LNG at US$6.00/mBTu).

Table 7
Expected System Costs – Coal and LNG Options - (Base Case)

	2004 Costs		**2008 Costs**		**2011 Costs**	
	Coal Plan	**LNG Plan**	**Coal Plans**	**LNG Plan**	**Coal Plan**	**LNG Plan**
Existing System	7.278	7.278	7.276	7.296	7.520	.415
Expansion-Interim	-	-	6.11	7.31	5.84	7.20
TOTAL System	**7.278**	**7.278**	**6.993**	**7.299**	**6.882**	**7.344**

As a competitive market will be introduced, the Office does not consider it appropriate to provide the detail which support the build up of these costs as doing so could compromise the commercial position of existing operators.

Market Arrangements

According to the All-Island Electric Licence 2001, addition of capacity after April 2004 should be decided on the basis of competitive bids, in which JPS itself may participate. The methodology and rules for the competition will be the subject of another decision, but for the purposes of this discussion, the Office would proffer that under ideal conditions, the call for bids should simply define the capacity needs, timing, expected capacity factor, perhaps siting, and that proposals should be based on proven technology.

Adoption of the principle to add the incremental intermediate capacity of 40 MW in 2005/2006 will provide sufficient time for the studies relating to LNG to be thoroughly done and for the subsequent competition rules to be introduced which will form the procedural basis to secure additions of capacity – in the longer term.

Finalization of the rules and preparation of the relevant documents, however, will require at least six months. It is unlikely that the first tranche or stop gap addition of 40 MW can be procured, under the rigorous competitive procedure that is envisaged, and be operational by end 2005/early2006. A fast-track but transparent approach, designed to secure the least cost solution must be adopted and in this regard, the following is suggested as possibilities for achieving this objective.

There are several options for adding the required 40 MW of interim capacity in such a manner as to achieve a least cost result. The Office is of the view though, that such additional capacity should not utilize single cycle gas turbine technology but should be medium or slow speed diesel technology utilizing HFO. Additionally, to minimize interconnection costs to the grid, the plant will have to be sited at an existing power station facility - Bogue, Old Harbour, Hunts Bay or Rockfort. The environmental challenges for bunkering at Bogue would eliminate that location and therefore Old Harbour, Hunts Bay or Rockfort would be the preferred sites.

The Office is disposed to the view that a limited competition, perhaps leveraging existing infrastructure and contracts would yield the least cost solution. The economics of procuring plant suitable for HFO and LNG would have to be considered in the economic and financial evaluation of the options received. Any plant added would be subject to a power purchase agreement regardless of whether the facility is owned by JPS or another independent power producer.

Treatment of Renewables and Alternate Energy

The OUR Act provides a duty for the Office to encourage the development and use of indigenous resources while the Energy

Policy gives clarity to the Government's objective to promote renewable and other alternate sources for generating electricity.

The Office is aware that the Government has committed to CARICOM to produce 10% of all its energy requirements from renewable sources by 2010 and has established the following targets:

- 6% by 2006
- 8% by 2010
- 12% by 2020

On this basis, the contribution from renewable sources during the planning period is shown in Table 8.

Table 8
Minimum Contribution from Renewable Energy Sources

	Total		**Contribution from Renewables**
Year	**Capacity (MW)**	**Energy (MW)**	**Energy (GWhrs)**
2006	846	4097.8	245.9
2010	1046	4702.3	282.2

In the pursuit of these objectives, the Office will be developing a series of policies and rules dealing with renewables, alternate energy, cogeneration, etc. which will set out the basis under which these may be added to the energy mix.

In introducing these rules, however, it must be clearly understood that the Office must continually balance the impact which these new technologies will have on the price of electricity to consumers.

Renewable technologies that do not offer firm capacity will not affect the Plan in terms of the capacity objectives, but will contribute energy to the system, perhaps even displacing some off peak energy.

Renewables that offer firm capacity ought really to be added within the context of a general call for proposals for the addition of capacity. The Office would not recommend that capacity such as this be added on an ad hoc basis because of the possibility that the least cost solution may not be the result and customers are therefore obliged to pay prices that are not based on optimal solutions.

Future Adjustments to the Expansion Plan

Although the All-Island Electric Licence 2001 contemplates that the planning process will be driven by JPS the Office considers this to be most inappropriate as a basis going forward and therefore it has decided to develop its own in-house capability to conduct expansion planning. Whilst this will not relieve JPS of its responsibilities under the Licence, this will ensure that the planning is conducted and maintained on a timely basis. The primary objective would be to update and make the expansion plan public annually. The Office has also adopted this position as being consistent with the Government's intentions as set out in the 1996 Energy Policy.

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JPSCO – LEAST COST GENERATION EXPANSION PLAN (2004-2012)

1.0 OVERVIEW

This Least Cost Expansion Plan (LCEP) details the capacity requirements to meet Jamaica's anticipated growth in electricity demand from 2004 through to 2012. It describes the basis on which these requirements have been established, the various economic options available and recommends on the preferred JPSCo strategy for achieving the least cost expansion of the country's generation reserve.

These conclusions are supported by detailed, engineering and planning, analyses that are the subject of separate documents and are highlighted in this document for easy reference. The important conclusion of the report is an Expansion Plan that defines the increment and timing of each capacity requirement as well as the preferred projects to meet this need. Where no such conclusions are drawn regarding projects for implementation, the reasons for this as well as the process to come to a final decision are outlined.

The document is broken down into the following areas of focus: -

1. Demand Projections;
2. Existing System Performance;
3. Capacity Needs;
4. Options to meet expansion requirements; and
5. Recommendations

DEMAND PROJECTIONS

The demand forecast is the most important determinant of our expansion requirements. The forecast, which is developed internally, is done on the basis of an econometric model, which establishes a correlation between primary economic determinants (obtained from official government statistics) and the demand for electricity.

Gross peak demand to date is 589.0 MW (September 2003). Energy demand in 2003 was 3696 GWh/yr. This represents growth of 1.3% and 4.9% growth in demand and energy respectively and a load factor of 74%.

Over the last decade energy and peak demand have been growing at approximately 5.0%. The significant exception being 2001 where growth was sharply lower due to a number of factors including:

- Significant reliability problems affecting supply to customers.
- Domestic economic problems disrupting normal economic activity for a few months; and
- The economic fallout of the September 11 tragedy in the United States.

Our most recent forecast of 2003 based on information up to 2002, suggested a continued growth of 4.5% per annum which was in keeping with the average growth rate over the last 5 years up to that time.

The forecast however, highlighted economic factors that could result in a lower demand due to:

1. Less than forecast economic growth
2. Dampening in demand due to success in loss reduction effort

Against this background a low forecast of 3.3% as compared to the base case of 4.5% was presented.

As it turns out, the demand in 2003 further confirms the more recent trend of a progressive dampening in demand and as such, for the purposes of the Expansion Plan we have sought to use the low forecast to develop the plan, to ensure its robustness and to mitigate against over investment in capacity.

Table 1
Average Compounded Growth Rates

	Last 10 Years (1992 – 2002)	Last 5 Years (1997 – 2002)	2001	2002	2003	Avg. Last 3 Years	Forecast
Peak Demand	5.1%	4.4%	1.5%	4.8%	1.3%	2.5%	3.5%
Energy	5.1%	5.0%	1.8%	4.9%	4.9%	3.9%	3.5%

Table 2
Demand Forecast

Year	Net Peak Demand (MW)[1]	Energy (GWh)
2003	571.3	3,696.0
2004	591.3	3,825.4
2005	612.0	3,959.2
2006	633.4	4,097.8
2007	655.6	4,241.2
2008	678.6	4,389.7
2009	702.3	4,543.3
2010	726.9	4,702.3
2011	752.3	4,866.9
2012	778.7	5,037.3

As illustrated in 2001 and 2003, there are factors that could impact the forecast in a significant way. Failure to achieve the stated levels of economic growth is likely to negatively impact the forecast and consequently the capacity requirements. It is our intention to continually monitor the forecast and appropriately adjust this to ensure that the Capacity Expansion programme for those projects not yet committed reflect the most current demand circumstance.

2.0 EXISTING SYSTEM: STATUS & PERFORMANCE

The projected performance of the existing system and its impact on average available production capacity is also an important determinant in developing the

[1] The Expansion Plan is based on Net Demand. This net demand is determined by Gross Metered Energy demand less Parasitic Load on the plants which is 3%. While this is not expected to change over the planning period it reflects the difference between gross and peak demand presented in the report.

model for future generation expansion. Planned retirement based on technical and economic obsolescence is given serious consideration and is incorporated into the plan where appropriate. Both are discussed below.

3.1 Capacity Status & Retirement Schedule

The JPSCo grid presently has 801 MW of total installed generating capacity of which 766 MW is available for dispatch. Of this, approximately 157 MW are in private power purchase contracts. The total capability is broken down as follows.

Table 3
Installed Capacity

JPSCo Owned	Old Harbour	Hunts Bay	Bogue	Rockfort	Other
+ Hydro	-	-	-	-	23.0
+ Steam	223.5	68.5	-	-	-
+ Diesel	-	-	-	36.0	-
+ Gas turbines	-	75.5	103.5	-	-
+ Comb. Cycle	-	-	114.0	-	-
IPPs	**74.2**	**-**	**-**	**60.0**	**23.1**
TOTAL	**297.7**	**144.0**	**217.5**	**96.0**	**46.1**

GRAND TOTAL: **801.3 MW**

Of the total capacity approximately 35 MW is presently unavailable for operation due to the following reasons:

- GT4 at Hunts Bay (21.5 MW) was forced out of service in 2001 due to significant damage to the turbine. An assessment of the status of the unit and the cost of repairs has led to the decision not to repair the unit at this time.

- One IPP (Jamaica Broilers) has been unavailable for service since April 2003 because of technical problems; reducing total capability by 12.1 MW. JPS had expected that this project would address its problems and return to service by the beginning of 2004 but found it necessary to terminate the contract as at December 2003. This project is therefore no longer a part of the capacity mix.

- 1.5 MW of Hydro Capacity is out of service because of significant damage to it civil infrastructure. The unreliability of the available water resource, does not justify making the significant capital investments to return the unit at this time.

In addition to the above the following changes in operating capacity are expected during 2004.

- Reduction in Jamalco by 6 MW

- It should be carefully noted that while the commissioning of the 20MW wind farm is expected in mid-2004. This is not expected to measurably impact the firm capacity requirements of the system because of the variable nature of wind. This is reflected in the energy only contract with the developers.

The individual plant capability and performance used in the plans is shown in Table 4 below.

Table 4
Plant Capability and Performance

Plants	Capacity Name plate	MCR	Technology	In Service Date	EFOR (%)	Availability (%)
A) Steam						
OH1	33.0	30.0	Oil-fired Steam	1968	8.0	85
OH2	60.0	60.0	Oil-fired Steam	1970	8.0	85
OH3	68.5	65.0	Oil-fired Steam	1972	8.0	85
OH4	68.5	68.5	Oil-fired Steam	1973	8.0	85
B6	68.5	68.5	Oil-fired Steam	1976	8.0	85
B) Diesels						
RF1	20.0	18.0	Slow speed diesel	1985	5.0	85
RF2	20.0	18.0	Slow speed diesel	1985	5.0	85
C) CC Plants						
GT 12	40.0	38.0		2002		
GT 13	40.0	38.0	Combined Cycle Plant	2002	3.0	90
ST 14	40.0	38.0		2003		
D) GTs						
GT 3	22.8	21.5	Combustion Turbine	1973	5.0	85
GT 4	22.8	21.5	Combustion Turbine	1974	5.0	85
GT 5	22.5	21.5	Combustion Turbine	1974	5.0	85
GT 6	18.5	14.0	Combustion Turbine	1990	5.0	90
GT 7	18.5	14.0	Combustion Turbine	1990	5.0	90
GT 8	16.5	14.0	Combustion Turbine	1992	5.0	90
GT 9	20.5	20.0	Combustion Turbine	1992	5.0	90
GT 10	33.0	32.5	Combustion Turbine	1993	5.0	85
GT 11	20.0	20.0	Combustion Turbine	2001	5.0	90
E) Hydro						
JPS Hydro Plants	23.0	21.5	Hydro			
F) IPPs						
IPPs (4 contracts)	158.6	145.2	Diesel/Steam		5.0	90

3.11 Performance

The power plants that are in the ownership of JPSCo have benefited from significant expenditures in extraordinary maintenance and upgrades to assure their performance is at or above the industry average, that is, availability (85%) and forced outage rates (6%). To be more specific, the following interventions have been made.

Table 5
Combustion Turbines

Aero derivative GTs	Gas Generator overhaul	Free turbine overhaul
G6	√	√
G7	√	√
G8	√	√
G9	√	√
G11	√	√
Industrial GTs		
GT4	- Out of service -	
GT5	Hot Gas Path Inspection 2002	
GT3	Hot Gas Path Inspection 2002	
GT10	Hot Gas Path Inspection 2003	

Steam Plants	Boiler	Turbine
OH 1	Superheater, Bank tube replacement 2003	Overhaul 2003
OH2	Tube replacement 2002	Overhaul 2002
OH3	Major O/H 2003	Overhaul Completed
OH4	Scheduled for major O/H 2004	Overhaul 2004
B6	Major O/H scheduled 2005	Overhaul 1999

Those activities already completed have put the major maintenance programme of those power plants in line with the OEM recommendations. The results of these interventions have started to bear fruit as evidenced by the improved availability and forced outage rates of these plants.

The following Table (6) illustrates the performance trends of the existing plants and the projected performance on which the expansion plan is based.

Table 6
Performance Trends

	1999	2000	2001	2002	2003	Target
System Availability (%)	87.8	86.0	79.4	82.1	82.0	**85.0**
System FOR (%)	8.2	8.1	12.1	11.8	6.0	**6.0**

Source: JPS official Stats

With the exception of the Jamaica Broiler units, the Independent Power Producers (IPPs) have been operating at or above the average system performance. Based on the age of these facilities and the terms of their contracts, they are expected to preserve this level of performance over the period.

For the JPSCo units, the following outstanding major maintenance activities are programmed over the next 18-24 months to ensure that target system performance is sustainable:

a. Major overhaul of Old Harbour unit #4 including replacement of super-heater tube, which has been a historical cause of boiler tube leaks.

b. Replacement of obsolete forced draft fan on OH2 in 2004. This has been the primary cause of forced outages and de-ratings on this unit.

c. Major rehabilitation of Hunts Bay B6 (turbine & boiler.)

Over the planning period the proposed major maintenance interactions are summarized below in Table 7.

TABLE 7
<u>JPS Major Maintenance Plan</u>

Plants	Year									
	2003	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**
A) Steam										
OH1					MAJ					MAJ
OH2				MAJ					MAJ	
OH3	MAJ					MAJ				
OH4		MAJ					MAJ			
B6			MAJ					MAJ		
B) Diesels										
RF1			MAJ		MAJ		MAJ		MAJ	
RF2		MAJ		MAJ		MAJ		MAJ		MAJ
C) CC Plants										
GT 12			HGPI		HGPI				HGPI	
GT 13			HPGI		HGPI			HGPI		
ST 14							MAJ			
<u>D) GTs</u>										
GT 3				MAJ					MAJ	
GT 5			MAJ					MAJ		
GT 6			MAJ		MAJ			MAJ		MAJ
GT 7			MAJ		MAJ			MAJ		MAJ
GT 8			MAJ			MAJ			MAJ	
GT 9		MAJ		MAJ		MAJ		MAJ		
GT 10			HGPI			HGPI			HGP	
GT 11					MAJ			MAJ		
KEY										
HGPI	Hot Gas Path Inspection									
MAJ	Major Overhaul									

3.12 <u>Retirement Schedule</u>

a. <u>JPSCo</u>

On the basis of the above performance and anticipated cost of operation to keep these assets in service, there is presently no basis for technical or economic obsolescence of these units. In view of this, the LCEP does not contemplate retirement of existing plants over the planning period 2004-2012.

Given the extent of major maintenance interventions made over the last two years, it is not anticipated that the future cost of operation (in real terms) will be greater than the average cost of maintenance incurred over the last 5 years. Examining these cost against the production cost of the best replacement alternative as shown in table 6 below does not now justify retiring these plants on the basis of economic obsolescence.

Retirement Analysis

Table 8

Base-load Plants

Plant	CF	O&M ($M)	Fuel Rate (¢/KWh)	Total Cost ($M/yr)	Total Rate (¢/KWh)	Alternative	Fuel Rate (¢/KWh)	Life Cycle Cost ($/yr)	Total Rate (¢/kwh)
Base Load									
OH4	0.8	2	4.4	23.3	4.86	Coal	1.31	28.5	5.94
OH3	0.8	2	4.5	22.6	4.96	Coal	1.31	27.0	5.93
OH2	0.8	2	5.0	22.9	5.45	Coal	1.31	25.0	5.93
HB B6	0.8	2	4.5	23.4	4.88	Coal	1.31	28.5	5.94
Rockfort	0.9	2	3.4	6.3	5.02	Coal	1.31	7.5	5.92
Intermediate									
OH1	0.6	2	5.5	10.7	6.81	MSD	3.45	13.1	8.28
Peaking									
GT5	0.2	0.5	10.9	6.7	11.7	GT	9.26	9.3	16.41

Sample Calculation

Cap 68,500; Energy 480,048,000KWh

OH4:

Capacity	68,500 KW
Cap Factor	80%
Energy	480,048,000 kwh
O&M/yr	$2M

Fuel Rate:

Heat Rate	12,514 BTU/KWh
Fuel Price	$3.54/MMBTU
	0.044$/KWh
	$21.3M
Total Cost	$23.3M
Rate	$0.048/KWh

Alternative: **Coal**

Annual Cap Cost	$16.8M
Annual O&M (F & V)	$ 5.4M
Total	$22.2M

Fuel Rate:

Heat Rate	10,200 BTU/KWh
Fuel Price	$1.29/MMBTU
	$0.013/KWh
	$ 6.3M
Total Cost	$28.5M
Rate	$0.059/KWh

Given the significant capital cost involved, no immediate plans are afoot to restore GT4 at this time. Nevertheless this option is being assessed against other strategies to restore the lost capacity.

b. IPPs

In respect of the independent producers, none of the contracts will expire over the planning period. Jamalco, which currently provides 11 MW has indicated that its process expansion plan for alumina will necessitate an increase in its parasitic load and a commensurate reduction in output to JPSCo of 6 MW in 2004. No specific timetable has been set but the study assumes this capacity to be unavailable as at January 2004. The Jamaica Broilers EAL/ERI contract has been terminated.

The forecast capacity available from existing plants over the planning period based on the above factors is as follows.

Table 9
Existing and Committed Gross Capacity over Planning Horizon

	2004	2005-2012
Installed (BOY)	776	770
Outage/Retire	6	-
Available Capacity	770	770

1. **BOY: Beginning of year**

3.0 CAPACITY REQUIREMENTS (2004-2012)

Generating capacity needs are determined on the basis of a need to preserve/achieve the mandated level of reliability to customers as stipulated within the Company's operating Licence. This reliability, for the purposes of system expansion planning, is measured as a loss of load probability of 0.55% (equivalent of 48 hrs per year). In more direct terms, it facilitates the ability to have the two largest units (or their equivalent) off the grid and still be able to meet the forecast demand for electricity. This is a very effective rule of thumb as it represents a reasonably severe contingency to plan for (one large unit out on maintenance and another large unit trips off on forced outage). Based on today's system configuration and relative unit sizes, this translates to a minimum requirement for approximately 25% reserve margin. Over the years, this will become progressively less as the relative size of units to the system become smaller.

The expansion analyses are carried out using the WASP III model, which affords us the opportunity through "monte carlo" simulations to examine a wide range of system configurations based on available technologies and costs and choose the most economical approach to meet the reliability criteria. On this basis, the following capacity needs have been established.

Table 10
Capacity Needs

		Pre. Expansion	
Year	**Gross Demand (MW)**	**Gross Capacity (MW)**	**Reserve**
2003	589	766	30%
2004	609	766	26%
2005	631	766	21%
2006	653	766	17%
2007	675	766	13%
2008	699	766	9%
2009	724	766	6%
2010	749	766	2%
2011	775	766	-1%
2012	802	766	-5%

This justifies a definite need for expansion.

4.0 EXPANSION OPTIONS

In reviewing alternatives to meet the aforementioned capacity needs, a number of technology and fuel options were examined. The following table provides a shortlist of those options that were arrived at by screening alternatives down to power technologies that are practical to meet Jamaica's needs based on system size as well as resource availability.

Renewable technologies were also given consideration but were ruled out as sources of firm generating capacity because of the variability and unpredictability of the available resource. Opportunities in Renewable Power will however continue to be evaluated during the expansion window and viable alternatives for meeting energy needs will be valued at marginal cost. We intend that viable options that represent a savings for the consumer and that create no technical issues for operating reliability will be presented to the regulator for consideration. Table 11 summarizes the options considered under this plan.

Table 11
Options for Expansion

Technology	Coal	Petcoke	Orimulsion	LNG	HFO	ADO
1. Steam (120 MW)	√	√	√	√	√	
2. Diesels (5-30) (Medium/Slow speed)				√	√	
3. Combined Cycle				√		√
4. Combustion Turbines				√		√

The cost information used in determining economic preference was derived from a combination of sources, namely: -

- Studies carried out by industry experts
- Indicative prices from OEM's
- Project costs from past projects
- Detailed engineering cost estimates done by our engineering consultants (Sergeant & Lundy, AMEC & MPR)

In each case where necessary and appropriate, the numbers were modified to reflect the particular circumstances of developing these projects in Jamaica (prices, overheads, permit requirements etc.). The following resulting data was used for the candidate options.

Table 12
Fuel Options and Prices

Fuels	Price ($/Unit)[2]	Heating Value (Mbtu/Unit)	Price ($/Mbtu)	Source
LNG (M^3)[3]	-	-	3.90	Trinidad
Coal (ton)	$32	25.0	1.28	Columbia/Venezuela
Petcoke (ton)	$17	30.6	0.57	Venezuela
Orimulsion (bbls)	$44	28.4	1.55	Venezuela
HFO (bbls)	$22	6.2	3.54	Petrojam (Jamaica)
ADO (bbls)	$38	5.81	6.55	Petrojam (Jamaica)

Source: JPS/Mirant (Market research and information)

Table 13
Equipment Options and Prices

Technology	Capital Cost [4]($/kW)	Plant Size (MW)	Heat Rate (Btu/kWh)	Fixed O&M ($/kW/yr)	VAR O&M (¢/kWh)	Lead Time (Month)
Combined Cycle (LNG)	900	120	7,500	11.9	0.3	22-24
Gas Turbine	600	40	10,350	4.5	0.15	9-12
Steam (coal)	1550	120	10,200	29.8	0.7	36
MS Diesel	1000	15	8,400	21.6	1.5	12
SS Diesel	1400	30	7,600	29.8	0.8	24

Source: JPS/Mirant (Research and information from OEM on projects recently implemented)

[2] Prices are net of local taxes
[3] Not enough information was available at the time this LCEP was finalised to determine the price at which Gas could be landed in Jamaica. This is the subject of a detailed study being undertaken by the governments of Jamaica and Trinidad & Tobago with the support of the JPSCo and the bauxite and alumina industry. For the purposes of this study the price of Gas that is used represents the benchmark price at which it becomes a practical and economic equivalent to solid fuels, which represent the cheapest option for which specific price information is available.
[4] Overnight Cost

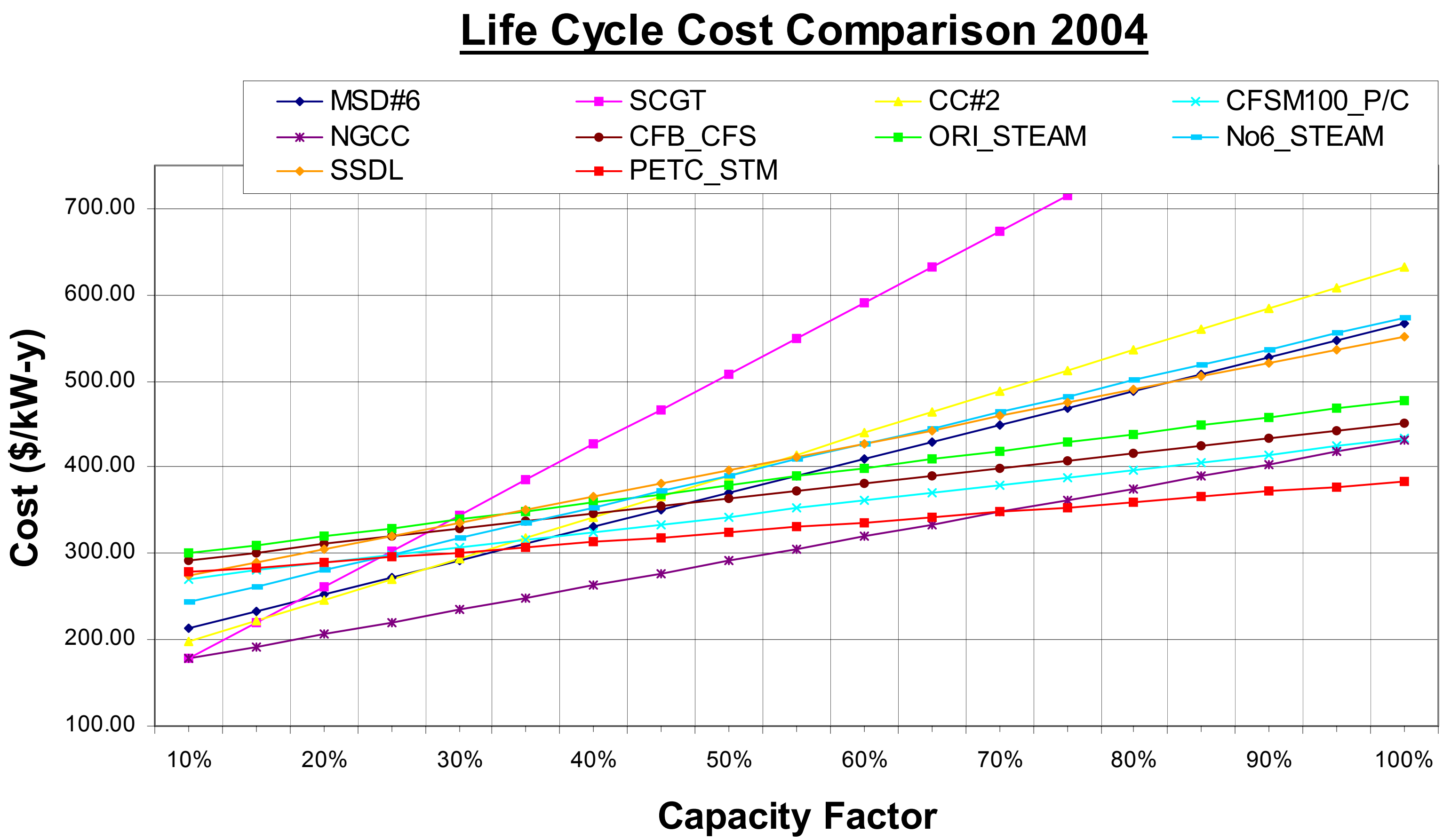
N.B. The capital cost for coal and gas does not include the cost for fuel handling infrastructure to facilitate bringing these new fuels into Jamaica.

The screening curve in figure 1.2 shows the relative lifecycle cost for each technology based on the levels of utilisation.

Note

1. No site specific costs included; taxes not included
2. Best point heat rate

Figure 1



Life Cycle Cost Comparison 2004
MSD#6
SCGT
CC#2
CFSM100_P/C
NGCC
CFB_CFS
ORI_STEAM
No6_STEAM
SSDL
PETC_STM
700.00
600.00
500.00
400.00
300.00
200.00
100.00
Cost ($/kW-y)
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
Capacity Factor

Screening Analysis

The screening curve in figure 1 (using data in Tables 9 & 10) has established the following technology preferences for the different duty cycles for required incremental capacity.

A. Lead Time Greater Than 3 yrs

	Top Two Technologies
1. Base Load (>45%)	Coal fired Steam / Combined Cycle on Natural Gas/ADO
2. Intermediate (15% – 45%)	Diesel Engines/ Combined Cycle on Natural Gas/ADO
3. Peaking and Standby (0 – 15%)	Combustion Turbine

B. Lead Time Less Than 2yrs

1. Base/Intermediate	Diesel Engines/ Combined Cycle on Natural Gas/ADO
2. Peaking	Combustion Turbine

The Plan

The detailed WASP simulations are consistent with these preliminary screening conclusions. It is reasonable therefore to conclude that the decision on fuel diversity is fundamental to the competitiveness of electricity cost and the generation expansion program. Given that no conclusion has yet been drawn on the preferred source for diversity, we have presented expansion plans for both a gas based and a solid base expansion plan.

TABLE 14
Expansion Profile

	Gas Plan (at US$3.90/MMBTU)	**Solid Fuel Plan**
Total Present Worth Investment and Operating Cost (US$Billion)	1.95	1.98
2004		
2005	40 MW (Stop Gap)	40 MW (Stop Gap)
2006	40 MW CC Plant (120)	40 MW (Stop Gap)
2007	80 MW	
2008		120 MW
2009		
2010	40 MW CC Plant (120)	
2011	80 MW	120 MW
2012		
Total	**280 MW**	**320 MW**

The establishment of technology preferences primarily considers the strategic dictates of the State for fuel diversity and more importantly establishes a price benchmark for least cost benchmark of the system. This does not prohibit the development of alternative proven technologies that can beat this cost benchmark. While known environmental and infrastructure development cost that are common have been taken into consideration in these costs, it is anticipated that the cost implication of the peculiarity of sites and environmental requirements for each project and technology will be factored into the competitive bidding process.

5.3 **Fuel Infrastructure (Implication of Fuel Diversity)**

Critical to the success of fuel diversification is the treatment of the initial infrastructure cost required to introduce a new fuel source to the island. Especially in an environment of competitive power generation it is difficult to achieve fuel diversity if the cost of the generation project is going to be burdened with fuel infrastructure investments. To facilitate diversity, it will be necessary for the cost of infrastructure to be normalized over the fuel consumption over a sufficiently long period to avoid the shock of one project. This may in the final analysis require that the Government take the lead in encouraging a partnership with fuel suppliers to facilitate the infrastructure development.

The findings of this Gas study and the positions of the OUR and Government on the approach to encouraging fuel Diversity to Jamaica will be critical to the ultimate strategy that will be implemented. It is anticipated that this will be completed within six (6) month of the date of this study.

6.0 RECOMMENDATIONS

Based on the aforementioned JPS is proposing the following Expansion Plan.

1. It must be emphasized that fuel diversity is an indispensable component to ensure the competitiveness of electricity cost in Jamaica. Core to the Expansion Plan therefore is the determination of the fuel diversity option of choice. The primary options under consideration are gas and solid fuels. It is imperative therefore that Government concludes its decision within the next six months to keep the propose expansion plan on track.

2. **Interim Plan – 40 MW stop gap** Given the supply demand balance, there is the need for installation of an additional 40 MWs by mid to end 2005 to ensure continued reliability of service. This implementation will:
   i. Give Government an opportunity to conclude its gas feasibility study in six months and facilitate the next tranche of capacity by 2007
   ii. Afford the regulator and opportunity to put the framework in place to allow this next tranche to be implemented under the competitive model

3. **Future base load expansion up to 2012 is 2x120 MW**

The economic choice for expansion hinges on the conclusion of Government's gas feasibility study. In this regard we have presented two options to meet the capacity expansion requirements over the next five years

Option 1

If Government can meet the requirement to land gas in Jamaica at $3.90/MMBTU then we propose the implementation of a gas based Expansion Plan, which makes Combined Cycle the technology of choice and the economic benchmark for any competitive expansion project. It should be note that even if the development of gas infrastructure cannot meet the 2007 timeline for the first tranche of capacity expansion, the combined cycle technology operating for up five years on ADO then converting to gas would still represent the most competitive option.

Option 2

If the gas strategy is determined to be infeasible then we recommend the implementation of a solid fuel based Expansion Plan. In this instance the benchmark technology and price is based on coal-fired steam generating technology. Given the lead time for coal there would be the need for an additional 40 MW of stop gap capacity in 2006 to ensure reliability until the coal plant project can be brought on stream in 2007.

Under both these strategies, Government and the regulator needs to provide a clear philosophy on the treatment of initial infrastructure cost to facilitate introduction of these new fuel sources. This we believe is important to attracting investments to develop these facilities independently of the power plant expansion projects.

The plans and decision tree along with the attendant cost of the investment programmes are summarised below.

FIGURE 2

Expansion Plan Decision Tree

FIGURE 3

NATURAL GAS PLAN

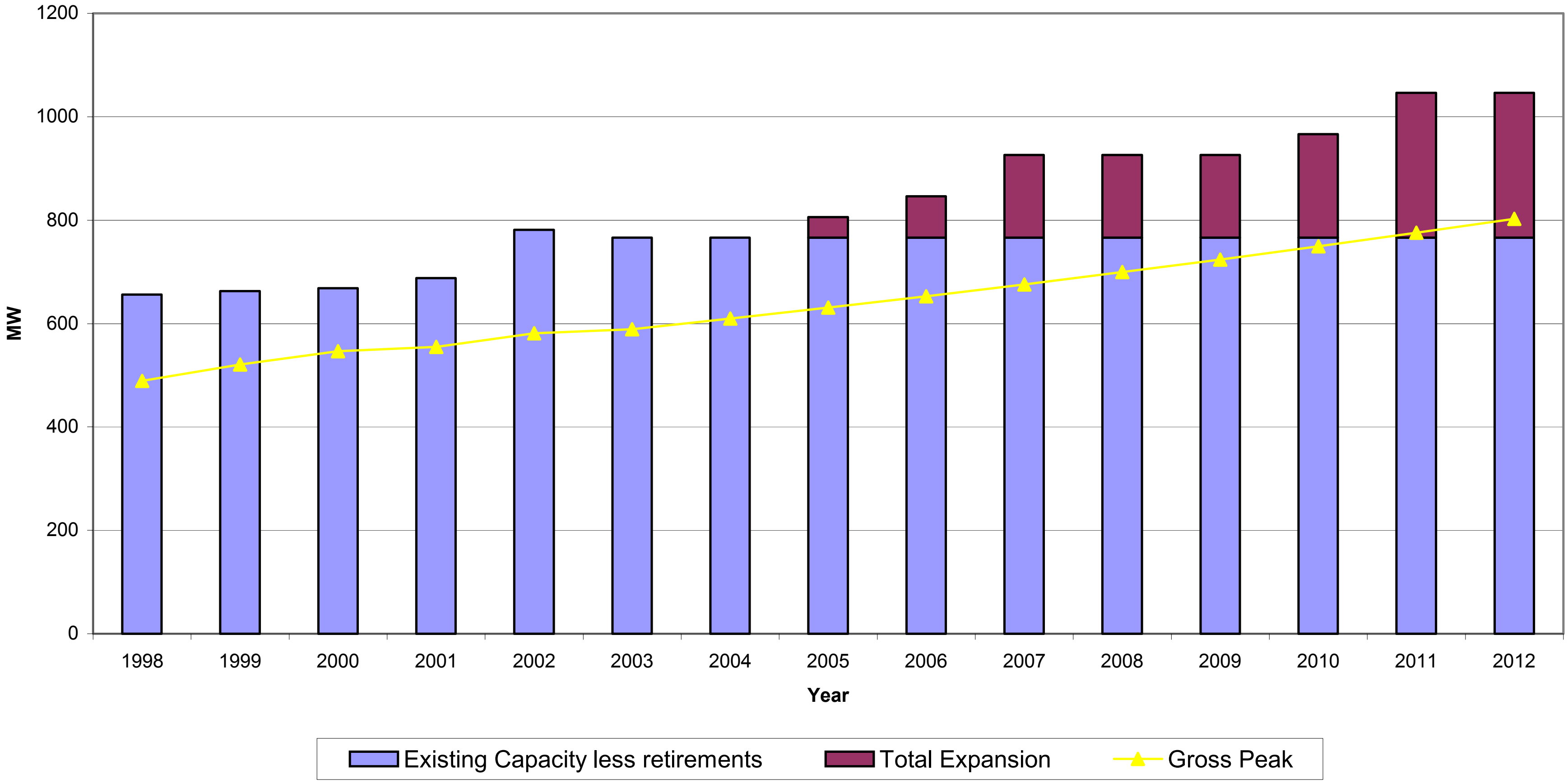
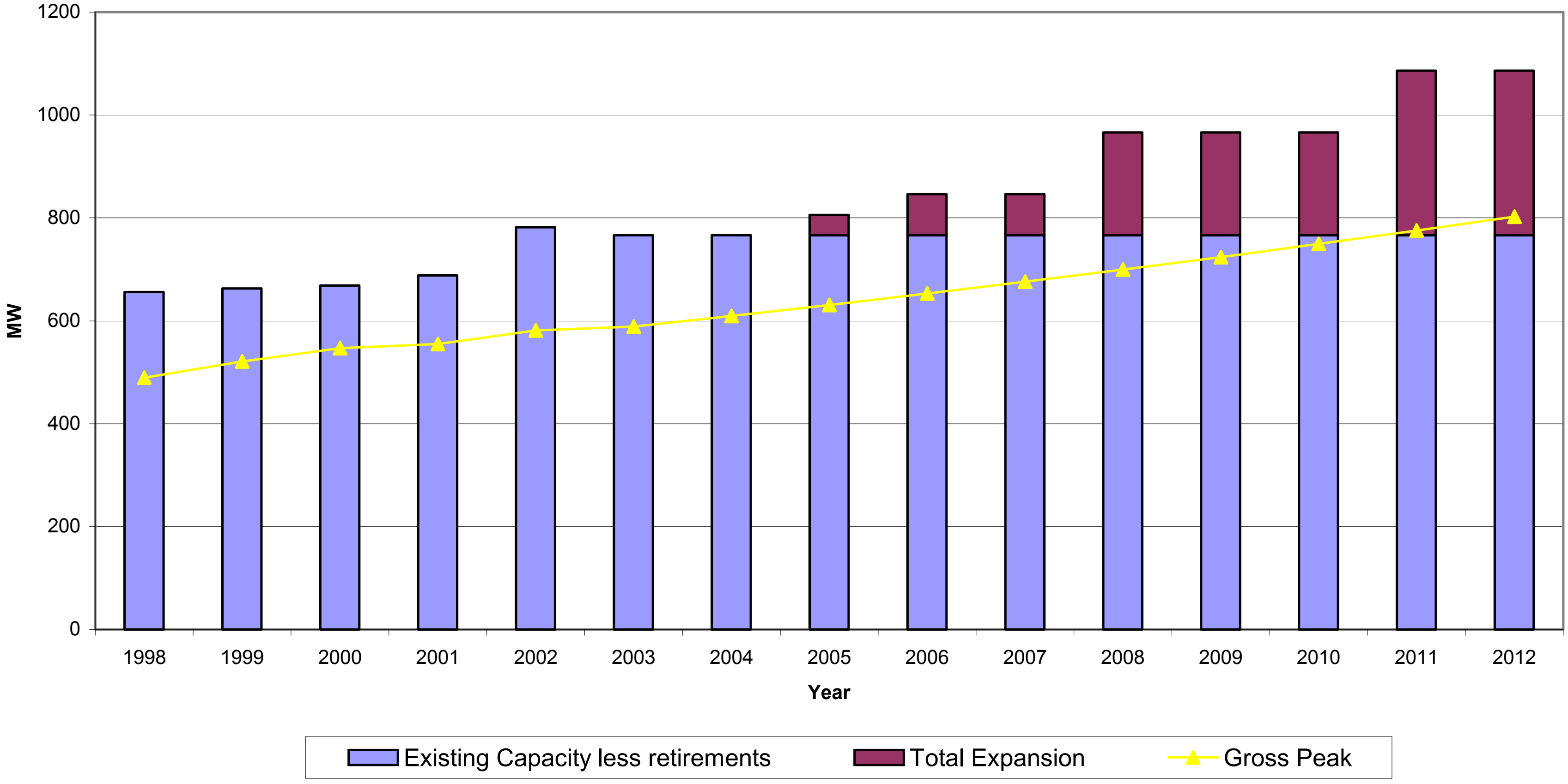


FIGURE 4

SOLID FUEL EXPANSION



APPENDIX A

SUMMARY REPORT
ON A GENERATION EXPANSION PLAN FOR

PROCESSED BY THE WASP-III COMPUTER PROGRAM PACKAGE
OF THE IAEA

STUDY PERIOD

2004 - 2017

PLANNING PERIOD

2004 - 2017

EXPANSION USING COMBINED CYCLE ON NATURAL GAS

DATE OF REPORT : Feb 2004
STUDY CARRIED OUT BY : MIRANT/JPS

THIS IS A LIST OF THE DIFFERENT TYPES OF ELECTRIC POWER PLANTS
USED IN THE STUDY.
THE NUMERIC CODES ARE USED BY THE COMPUTER PROGRAMS

```
0  HFO    Bunker'C (NO6)
1  COAL   Coal
2  DISL   Diesel (NO2)
3  NATG  NATURAL GAS
4  PETC  PETCOKE
5  ORIM  ORIMULSION
6  ****  NOT APPLICABLE
7  ****  NOT APPLICABLE
8  ****  NOT APPLICABLE
9  ****  NOT APPLICABLE
   HROR  RUN-OF-RIVER PLANT
   HSTO  SHORT TERM STORAGE
```

ANNUAL LOAD DESCRIPTION

PERIOD(S) PER YEAR : 4

YEAR	PEAKLOAD MW	GR.RATE %	MIN.LOAD MW	GR.RATE %	ENERGY GWH	GR.RATE %	LOADFACTOR %
2001	538.2	-	223.9	-	3361.3	-	71.29
2002	563.9	4.8	234.6	4.8	3521.8	4.8	71.29
2003	571.3	1.3	267.5	14.0	3701.8	5.1	73.97
2004	591.3	3.5	276.9	3.5	3831.3	3.5	73.97
2005	612.0	3.5	286.6	3.5	3965.5	3.5	73.97
2006	633.4	3.5	296.6	3.5	4104.1	3.5	73.97
2007	655.6	3.5	307.0	3.5	4248.0	3.5	73.97
2008	678.6	3.5	317.8	3.5	4397.0	3.5	73.97
2009	702.3	3.5	328.9	3.5	4550.6	3.5	73.97
2010	726.9	3.5	340.4	3.5	4710.0	3.5	73.97
2011	752.3	3.5	352.3	3.5	4874.6	3.5	73.97
2012	778.7	3.5	364.6	3.5	5045.6	3.5	73.97
2013	805.9	3.5	377.4	3.5	5221.9	3.5	73.97
2014	834.1	3.5	390.6	3.5	5404.6	3.5	73.97
2015	863.3	3.5	404.3	3.5	5593.8	3.5	73.97
2016	893.5	3.5	418.4	3.5	5789.5	3.5	73.97
2017	924.8	3.5	433.1	3.5	5992.3	3.5	73.97

FIXED SYSTEM

SUMMARY DESCRIPTION OF THERMAL PLANTS IN YEAR 2001

NO.	NAME	NO. OF SETS	MIN. LOAD MW	CAPA CITY MW	HEAT RATES KCAL/KWH BASE LOAD	HEAT RATES KCAL/KWH AVGE INCR	FUEL COSTS CENTS/ MILLION KCAL DMSTC	FUEL COSTS CENTS/ MILLION KCAL FORGN	FUEL TYPE	FAST SPIN RES %	FOR %	DAYS SCHL MAIN	MAIN CLAS MW	O&M (FIX) $/KWM	O&M (VAR) $/MWH
3	OH2	1	30.	57.	3659.	3334.	209.0	1357.0	0	10	8.0	26	60.	.38	6.70
4	RF1	1	9.	17.	2511.	2063.	212.0	1433.0	0	10	5.0	37	20.	.93	8.00
5	OH4	1	30.	65.	3195.	2901.	209.0	1357.0	0	10	8.0	25	60.	.33	6.70
6	GT4	1	5.	21.	6514.	2357.	272.0	3486.0	2	0	5.0	37	20.	.39	5.00
7	GT5	1	5.	21.	7104.	2698.	272.0	3486.0	2	0	5.0	37	20.	.39	5.00
8	GT10	1	8.	32.	5048.	2523.	272.0	3486.0	2	0	5.0	37	30.	.26	5.00
9	RF2	1	9.	17.	2511.	2063.	212.0	1433.0	0	10	5.0	37	20.	.93	8.00
10	JPPC	2	10.	30.	0.	0.	.0	.0	0	10	7.0	11	30.	50.00	35.00
11	GT6	1	5.	14.	5244.	3450.	157.0	3651.0	2	0	5.0	18	20.	.60	5.00
12	GT7	1	5.	14.	5390.	3129.	157.0	3651.0	2	0	5.0	18	20.	.60	5.00
13	GT3	1	5.	21.	6702.	2451.	157.0	3651.0	2	0	5.0	37	20.	.39	5.00
14	GT8	1	5.	14.	5944.	2908.	157.0	3651.0	2	0	5.0	18	20.	.60	5.00
15	GT9	1	8.	20.	7694.	622.	157.0	3651.0	2	0	5.0	18	20.	.42	5.00
16	JEP	8	3.	9.	0.	0.	.0	.0	0	0	6.0	15	20.	40.00	50.00
17	JAML	1	10.	11.	0.	0.	.0	.0	0	0	5.0	18	20.	14.00	37.00
18	BRLS	1	10.	12.	0.	0.	.0	.0	0	0	5.0	18	20.	15.00	28.00
19	HBB6	1	30.	65.	3436.	2715.	209.0	1410.0	0	10	8.0	26	60.	.33	6.70
20	OH1	1	14.	29.	3906.	3512.	209.0	1357.0	0	10	8.0	26	30.	.75	6.70
21	OH3	1	30.	62.	3578.	2546.	209.0	1357.0	0	10	8.0	26	60.	.35	6.70
22	BOGT	1	8.	20.	6300.	885.	157.0	3651.0	2	0	5.0	18	25.	.42	5.00
23	CCGT	0	8.	38.	6300.	2146.	202.0	3335.0	2	0	5.0	18	40.	.25	5.00
24	ALCO	0	4.	5.	0.	0.	.0	.0	0	0	5.0	18	20.	14.00	37.00
25	GT05	0	8.	38.	6300.	2146.	202.0	3335.0	2	0	5.0	18	40.	.25	5.00

FIXED SYSTEM
SUMMARY DESCRIPTION OF COMPOSITE HYDROELECTRIC PLANT TYPE HROR
*** CAPACITY IN MW * ENERGY IN GWH ***
FIXED O&M COSTS : 2.000 $/KW-MONTH

	P		HYDROCONDITION 1		
	R	P	PROB.: 1.00		
	O	E	CAPACITY		ENERGY
YEAR	J	R	BASE	PEAK	
2001	7	1	7.	0.	14.
		2	11.	0.	25.
		3	11.	0.	23.
		4	12.	0.	25.
		INST.CAP.		11.	
		TOTAL ENERGY			88.

FIXED SYSTEM
THERMAL ADDITIONS AND RETIREMENTS
NUMBER OF SETS ADDED AND RETIRED(-)
2001 TO 2017

YEAR: 19.. (200./20..)

NO.	NAME	2	3	4	5	6	7	8	9	10	11	12	13	14	15
6	GT4		-1												
10	JPPC														-2
16	JEP														-8
17	JAML			-1											
18	BRLS			-1											
20	OH1														-1
23	CCGT	2	-2												
24	ALCO			1											

FIXED SYSTEM
SUMMARY OF INSTALLED CAPACITIES
(NOMINAL CAPACITIES (MW))

	HYDROELECTRIC				THERMAL										TOTAL
	HROR		HSTO		F U E L T Y P E										
					0	1	2	3	4	5	6	7	8	9	
YEAR	PR.	CAP	PR.	CAP	HFO	COAL	DISL	NATG	PETC	ORIM	****	****	****	****	
2001	7	11.	0	0.	467.	0.	177.	0.	0.	0.	0.	0.	0.	0.	656.
2002					467.	0.	252.	0.	0.	0.	0.	0.	0.	0.	731.
2003					467.	0.	156.	0.	0.	0.	0.	0.	0.	0.	635.
2004					449.	0.	156.	0.	0.	0.	0.	0.	0.	0.	617.
2015					289.	0.	156.	0.	0.	0.	0.	0.	0.	0.	456.

VARIABLE SYSTEM

SUMMARY DESCRIPTION OF THERMAL PLANTS

NO.	NAME	NO. OF SETS	MIN. LOAD MW	CAPA CITY MW	HEAT RATES KCAL/KWH BASE LOAD	AVGE INCR	FUEL COSTS CENTS/ MILLION DMSTC	KCAL FORGN	FUEL TYPE	FAST SPIN RES %	FOR %	DAYS SCHL MAIN	MAIN CLAS MW	O&M (FIX) $/KWM	O&M (VAR) $/MWH
1	GTRB	0	10.	38.	4133.	2098.	215.0	3569.0	2	0	3.0	18	40.	.37	1.50
2	CC#2	0	20.	115.	2268.	1839.	.0	2595.0	2	0	3.0	26	115.	.99	6.00
3	NGCC	0	20.	115.	2268.	1839.	.0	1547.0	3	0	3.0	26	115.	.99	6.00
4	CCFB	0	40.	115.	3150.	2311.	.0	511.0	1	10	5.0	26	115.	2.48	7.00
5	ORFS	0	40.	115.	3150.	2272.	.0	615.0	5	10	5.0	26	115.	2.87	7.00
6	MSDO	0	5.	38.	2117.	2146.	237.0	1400.0	0	10	6.0	33	40.	1.80	15.00
7	PFSM	0	40.	115.	3150.	2389.	.0	220.0	4	10	5.0	26	115.	4.61	7.50

OPTIMUM SOLUTION

ANNUAL ADDITIONS: CAPACITY(MW) AND NUMBER OF UNITS OR PROJECTS

FOR DETAILS OF INDIVIDUAL UNITS OR PROJECTS SEE VARIABLE SYSTEM REPORT

SEE ALSO FIXED SYSTEM REPORT FOR OTHER ADDITIONS OR RETIREMENTS

NAME:				GTRB	CC#2	NGCC	CCFB	ORFS	MSDO	PFSM	HROR	HSTO
SIZE (MW):				38.	115.	115.	115.	115.	38.	115.	0.	0.
	%LOLP											
YEAR	MAINT	NOMNT	CAP									
2001	.953		0.									
2002	.186		0.									
2003	.272		115.		1							
2004	.845		0.									
2005	.522		38.	1								
2006	.048		115.			1						
2007	.098		0.									
2008	.200		0.									
2009	.395		0.									
2010	.046		115.			1						
2011	.096		0.									
2012	.203		0.									
2013	.027		115.			1						
2014	.060		0.									
2015	.459		115.			1						
2016	.076		115.			1						
2017	.167		0.									
TOTALS			728.	1	1	5	0	0	0	0	0	0

SUMMARY OF
FIXED SYSTEM PLUS OPTIMUM SOLUTION
(NOMINAL CAPACITY (MW))

YEAR	0	1	2	3	4	5	6	7	8	9	TOTAL CAP
	THERMAL FUEL TYPE CAPACITIES										
	HFO	COAL	DISL	NATG	PETC	ORIM	****	****	****	****	
2001	467	0	177	0	0	0	0	0	0	0	645
2002	467	0	252	0	0	0	0	0	0	0	720
2003	467	0	271	0	0	0	0	0	0	0	738
2004	449	0	271	0	0	0	0	0	0	0	720
2005	449	0	309	0	0	0	0	0	0	0	758
2006	449	0	309	115	0	0	0	0	0	0	873
2007	449	0	309	115	0	0	0	0	0	0	873
2008	449	0	309	115	0	0	0	0	0	0	873
2009	449	0	309	115	0	0	0	0	0	0	873
2010	449	0	309	230	0	0	0	0	0	0	988
2011	449	0	309	230	0	0	0	0	0	0	988
2012	449	0	309	230	0	0	0	0	0	0	988
2013	449	0	309	345	0	0	0	0	0	0	1103
2014	449	0	309	345	0	0	0	0	0	0	1103
2015	289	0	309	460	0	0	0	0	0	0	1057
2016	289	0	309	575	0	0	0	0	0	0	1172
2017	289	0	309	575	0	0	0	0	0	0	1172

SUMMARY OF
FIXED SYSTEM PLUS OPTIMUM SOLUTION
(NOMINAL CAPACITY IN MW, ENERGY IN GWH)

	HYDROELECTRIC				TOTAL THERMAL	TOTAL	SYSTEM		ENERGY NOT SERVED
	HROR		HSTO		CAPACITY	CAP	RES.	LOLP.	HYDROCONDITION
YEAR	PR.	CAP	PR.	CAP			%	%	1
2001	7	11	0	0	645	656	21.9	.953	1.9
2002	7	11	0	0	720	731	29.6	.186	.3
2003	7	11	0	0	738	750	31.2	.272	.6
2004	7	11	0	0	720	732	23.7	.845	2.1
2005	7	11	0	0	758	769	25.7	.522	1.2
2006	7	11	0	0	873	884	39.6	.048	.1
2007	7	11	0	0	873	884	34.8	.098	.2
2008	7	11	0	0	873	884	30.3	.200	.5
2009	7	11	0	0	873	884	25.9	.395	1.0
2010	7	11	0	0	988	999	37.4	.046	.1
2011	7	11	0	0	988	999	32.8	.096	.2
2012	7	11	0	0	988	999	28.3	.203	.5
2013	7	11	0	0	1103	1114	38.2	.027	.1
2014	7	11	0	0	1103	1114	33.6	.060	.2
2015	7	11	0	0	1057	1069	23.8	.459	1.4
2016	7	11	0	0	1172	1184	32.5	.076	.3
2017	7	11	0	0	1172	1184	28.0	.167	.5

SUMMARY OF
FIXED SYSTEM PLUS OPTIMUM SOLUTION
EXPECTED GENERATIONS BY PLANT TYPE (GWH)

				THERMAL FUEL TYPES											
	HYDROELECTRIC			0	1	2	3	4	5	6	7	8	9		GR.
YEAR	HROR	HSTO	TOTAL	HFO	COAL	DISL	NATG	PETC	ORIM	****	****	****	****	TOTAL	TOTAL
2001	88	0	88	3072	0	200	0	0	0	0	0	0	0	3272	3360
2002	88	0	88	3148	0	286	0	0	0	0	0	0	0	3434	3522
2003	88	0	88	3013	0	600	0	0	0	0	0	0	0	3613	3701
2004	88	0	88	3015	0	727	0	0	0	0	0	0	0	3742	3830
2005	88	0	88	3065	0	811	0	0	0	0	0	0	0	3876	3964
2006	88	0	88	2632	0	487	896	0	0	0	0	0	0	4015	4103
2007	88	0	88	2717	0	542	901	0	0	0	0	0	0	4160	4248
2008	88	0	88	2806	0	599	904	0	0	0	0	0	0	4309	4397
2009	88	0	88	2891	0	665	906	0	0	0	0	0	0	4462	4550
2010	88	0	88	2482	0	412	1728	0	0	0	0	0	0	4622	4710
2011	88	0	88	2554	0	475	1757	0	0	0	0	0	0	4786	4874
2012	88	0	88	2639	0	539	1779	0	0	0	0	0	0	4957	5045
2013	88	0	88	2355	0	315	2464	0	0	0	0	0	0	5134	5222
2014	88	0	88	2417	0	381	2519	0	0	0	0	0	0	5317	5405
2015	88	0	88	1532	0	545	3428	0	0	0	0	0	0	5505	5593
2016	88	0	88	1364	0	325	4012	0	0	0	0	0	0	5701	5789
2017	88	0	88	1412	0	398	4095	0	0	0	0	0	0	5905	5993

D Y N P R O

SUMMARY OF CAPITAL COSTS OF ALTERNATIVES IN $/KW

PLANT	CAPITAL COSTS (DEPRECIABLE PART) DOMESTIC	FOREIGN	INCLUSIVE IDC %	CONSTR. TIME (YEARS)	PLANT LIFE (YEARS)	CAPITAL COSTS (NON-DEPREC. PART) DOMESTIC	FOREIGN
THERMAL PLANT CAPITAL COSTS							
GTRB	.0	638.8	6.47	.50	25.	.0	.0
CC#2	.0	964.3	13.45	2.00	25.	.0	.0
NGCC	.0	898.5	13.45	2.00	25.	.0	.0
CCFB	.0	1512.3	20.98	3.00	30.	.0	.0
ORFS	.0	1633.2	20.98	3.00	30.	.0	.0
MSDO	.0	1588.3	13.45	2.00	25.	.0	.0
PFSM	.0	1693.7	20.98	3.00	30.	.0	.0

```
1SOLUTION #  1 VARIABLE ALTERNATIVES BY YEAR
0 YEAR------ PRESENT WORTH COST OF THE YEAR ( K$ )------  OBJ.FUN.  LOLP  GTRB    NGCC    ORFS    PFSM
HSTO
0         CONCST    SALVAL    OPCOST    ENSCST     TOTAL   (CUMM.)    %        CC#2    CCFB    MSDO    HROR
  - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - -
- - - - - - - - - - - -

0 2017         0         0     33570        81     33652   2206607   .167   1   1   5   0   0   0   0   0
0
0 2016     12698      8834     36631        48     40544   2172955   .076   1   1   5   0   0   0   0   0
0
0 2015     14603      8450     41873       297     48324   2132411   .459   1   1   4   0   0   0   0   0
0
0 2014         0         0     56941        40     56981   2084088   .060   1   1   3   0   0   0   0   0
0
0 2013     19313      7681     62944        22     74597   2027107   .027   1   1   3   0   0   0   0   0
0
0 2012         0         0     72415       170     72585   1952510   .203   1   1   2   0   0   0   0   0
0
0 2011         0         0     79788        92     79880   1879925   .096   1   1   2   0   0   0   0   0
0
0 2010     29372      6529     88547        51    111441   1800046   .046   1   1   2   0   0   0   0   0
0
0 2009         0         0    104004       485    104490   1688605   .395   1   1   1   0   0   0   0   0
0
0 2008         0         0    114283       269    114552   1584115   .200   1   1   1   0   0   0   0   0
0
0 2007         0         0    126536       148    126684   1469563   .098   1   1   1   0   0   0   0   0
0
0 2006     51372      4993    139843        83    186306   1342879   .048   1   1   1   0   0   0   0   0
0
0 2005     13696      1069    168979      1048    182655   1156573   .522   1   1   0   0   0   0   0   0
0
0 2004         0         0    186387      2046    188434    973919   .845   0   1   0   0   0   0   0   0
0
0 2003     83852      4122    204539       664    284933    785485   .272   0   1   0   0   0   0   0   0
0
0 2002         0         0    237373       432    237806    500553   .186   0   0   0   0   0   0   0   0
0
0 2001         0         0    259895      2851    262747    262747   .953   0   0   0   0   0   0   0   0
0
```

SUMMARY REPORT
ON A GENERATION EXPANSION PLAN FOR

PROCESSED BY THE WASP-III COMPUTER PROGRAM PACKAGE
OF THE IAEA

STUDY PERIOD

2004 - 2017

PLANNING PERIOD

2004 - 2017

EXPANSION USING COAL FIRED STEAM PLANTS

DATE OF REPORT : Feb 2004
STUDY CARRIED OUT BY : MIRANT/JPS

THIS IS A LIST OF THE DIFFERENT TYPES OF ELECTRIC POWER PLANTS
USED IN THE STUDY.
THE NUMERIC CODES ARE USED BY THE COMPUTER PROGRAMS

0	HFO	Bunker'C (NO6)
1	COAL	Coal
2	DISL	Diesel (NO2)
3	NATG	NATURAL GAS
4	PETC	PETCOKE
5	ORIM	ORIMULSION
6	****	NOT APPLICABLE
7	****	NOT APPLICABLE
8	****	NOT APPLICABLE
9	****	NOT APPLICABLE
	HROR	RUN-OF-RIVER PLANT
	HSTO	SHORT TERM STORAGE

ANNUAL LOAD DESCRIPTION

PERIOD(S) PER YEAR : 4

YEAR	PEAKLOAD MW	GR.RATE %	MIN.LOAD MW	GR.RATE %	ENERGY GWH	GR.RATE %	LOADFACTOR %
2001	538.2	-	223.9	-	3361.3	-	71.29
2002	563.9	4.8	234.6	4.8	3521.8	4.8	71.29
2003	571.3	1.3	267.5	14.0	3701.8	5.1	73.97
2004	591.3	3.5	276.9	3.5	3831.3	3.5	73.97
2005	612.0	3.5	286.6	3.5	3965.5	3.5	73.97
2006	633.4	3.5	296.6	3.5	4104.1	3.5	73.97
2007	655.6	3.5	307.0	3.5	4248.0	3.5	73.97
2008	678.6	3.5	317.8	3.5	4397.0	3.5	73.97
2009	702.3	3.5	328.9	3.5	4550.6	3.5	73.97
2010	726.9	3.5	340.4	3.5	4710.0	3.5	73.97
2011	752.3	3.5	352.3	3.5	4874.6	3.5	73.97
2012	778.7	3.5	364.6	3.5	5045.6	3.5	73.97
2013	805.9	3.5	377.4	3.5	5221.9	3.5	73.97
2014	834.1	3.5	390.6	3.5	5404.6	3.5	73.97
2015	863.3	3.5	404.3	3.5	5593.8	3.5	73.97
2016	893.5	3.5	418.4	3.5	5789.5	3.5	73.97
2017	924.8	3.5	433.1	3.5	5992.3	3.5	73.97

FIXED SYSTEM

SUMMARY DESCRIPTION OF THERMAL PLANTS IN YEAR 2001

NO.	NAME	NO. OF SETS	MIN. LOAD MW	CAPA CITY MW	HEAT RATES KCAL/KWH BASE LOAD	AVGE INCR	FUEL COSTS CENTS/ MILLION DMSTC	KCAL FORGN	FUEL TYPE	FAST SPIN RES %	FOR %	DAYS SCHL MAIN	MAIN CLAS MW	O&M (FIX) $/KWM	O&M (VAR) $/MWH
3	OH2	1	30.	57.	3659.	3334.	209.0	1357.0	0	10	8.0	26	60.	.38	6.70
4	RF1	1	9.	17.	2511.	2063.	212.0	1433.0	0	10	5.0	37	20.	.93	8.00
5	OH4	1	30.	65.	3195.	2901.	209.0	1357.0	0	10	8.0	25	60.	.33	6.70
6	GT4	1	5.	21.	6514.	2357.	272.0	3486.0	2	0	5.0	37	20.	.39	5.00
7	GT5	1	5.	21.	7104.	2698.	272.0	3486.0	2	0	5.0	37	20.	.39	5.00
8	GT10	1	8.	32.	5048.	2523.	272.0	3486.0	2	0	5.0	37	30.	.26	5.00
9	RF2	1	9.	17.	2511.	2063.	212.0	1433.0	0	10	5.0	37	20.	.93	8.00
10	JPPC	2	10.	30.	0.	0.	.0	.0	0	10	7.0	11	30.	50.00	35.00
11	GT6	1	5.	14.	5244.	3450.	157.0	3651.0	2	0	5.0	18	20.	.60	5.00
12	GT7	1	5.	14.	5390.	3129.	157.0	3651.0	2	0	5.0	18	20.	.60	5.00
13	GT3	1	5.	21.	6702.	2451.	157.0	3651.0	2	0	5.0	37	20.	.39	5.00
14	GT8	1	5.	14.	5944.	2908.	157.0	3651.0	2	0	5.0	18	20.	.60	5.00
15	GT9	1	8.	20.	7694.	622.	157.0	3651.0	2	0	5.0	18	20.	.42	5.00
16	JEP	8	3.	9.	0.	0.	.0	.0	0	0	6.0	15	20.	40.00	50.00
17	JAML	1	10.	11.	0.	0.	.0	.0	0	0	5.0	18	20.	14.00	37.00
18	BRLS	1	10.	12.	0.	0.	.0	.0	0	0	5.0	18	20.	15.00	28.00
19	HBB6	1	30.	65.	3436.	2715.	209.0	1410.0	0	10	8.0	26	60.	.33	6.70
20	OH1	1	14.	29.	3906.	3512.	209.0	1357.0	0	10	8.0	26	30.	.75	6.70
21	OH3	1	30.	62.	3578.	2546.	209.0	1357.0	0	10	8.0	26	60.	.35	6.70
22	BOGT	1	8.	20.	6300.	885.	157.0	3651.0	2	0	5.0	18	25.	.42	5.00
23	CCGT	0	8.	38.	6300.	2146.	202.0	3335.0	2	0	5.0	18	40.	.25	5.00
24	ALCO	0	4.	5.	0.	0.	.0	.0	0	0	5.0	18	20.	14.00	37.00
25	GT05	0	8.	38.	6300.	2146.	202.0	3335.0	2	0	5.0	18	40.	.25	5.00

FIXED SYSTEM

SUMMARY DESCRIPTION OF COMPOSITE HYDROELECTRIC PLANT TYPE HROR

*** CAPACITY IN MW * ENERGY IN GWH ***

FIXED O&M COSTS : 2.000 $/KW-MONTH

	P		HYDROCONDITION 1		
	R	P	PROB.: 1.00		
	O	E	CAPACITY		ENERGY
YEAR	J	R	BASE	PEAK	
2001	7	1	7.	0.	14.
		2	11.	0.	25.
		3	11.	0.	23.
		4	12.	0.	25.
	INST.CAP.			11.	
	TOTAL ENERGY				88.

FIXED SYSTEM
THERMAL ADDITIONS AND RETIREMENTS
NUMBER OF SETS ADDED AND RETIRED(-)
2001 TO 2017

YEAR: 19.. (200./20..)

NO.	NAME	2	3	4	5	6	7	8	9	10	11	12	13	14	15
6	GT4		-1												
10	JPPC														-2
16	JEP														-8
17	JAML			-1											
18	BRLS			-1											
20	OH1														-1
23	CCGT	2	-2												
24	ALCO			1											

FIXED SYSTEM
SUMMARY OF INSTALLED CAPACITIES
(NOMINAL CAPACITIES (MW))

	HYDROELECTRIC				THERMAL										TOTAL
	HROR		HSTO		F U E L T Y P E										
					0	1	2	3	4	5	6	7	8	9	
YEAR	PR.	CAP	PR.	CAP	HFO	COAL	DISL	NATG	PETC	ORIM	****	****	****	****	
2001	7	11.	0	0.	467.	0.	177.	0.	0.	0.	0.	0.	0.	0.	656.
2002					467.	0.	252.	0.	0.	0.	0.	0.	0.	0.	731.
2003					467.	0.	156.	0.	0.	0.	0.	0.	0.	0.	635.
2004					449.	0.	156.	0.	0.	0.	0.	0.	0.	0.	617.
2015					289.	0.	156.	0.	0.	0.	0.	0.	0.	0.	456.

VARIABLE SYSTEM
SUMMARY DESCRIPTION OF THERMAL PLANTS

NO.	NAME	NO. OF SETS	MIN. LOAD MW	CAPA CITY MW	HEAT RATES KCAL/KWH BASE LOAD	HEAT RATES KCAL/KWH AVGE INCR	FUEL COSTS CENTS/ MILLION KCAL DMSTC	FUEL COSTS CENTS/ MILLION KCAL FORGN	FUEL TYPE	FAST SPIN RES %	FOR %	DAYS SCHL MAIN	MAIN CLAS MW	O&M (FIX) $/KWM	O&M (VAR) $/MWH
1	GTRB	0	10.	38.	4133.	2098.	215.0	3569.0	2	0	3.0	18	40.	.37	1.50
2	CC#2	0	20.	115.	2268.	1839.	.0	2595.0	2	0	3.0	26	115.	.99	6.00
3	NGCC	0	20.	115.	2268.	1839.	.0	1547.0	3	0	3.0	26	115.	.99	6.00
4	CCFB	0	40.	115.	3150.	2311.	.0	511.0	1	10	5.0	26	115.	2.48	7.00
5	ORFS	0	40.	115.	3150.	2272.	.0	615.0	5	10	5.0	26	115.	2.87	7.00
6	MSDO	0	5.	38.	2117.	2146.	237.0	1400.0	0	10	6.0	33	40.	1.80	15.00
7	PFSM	0	40.	115.	3150.	2389.	.0	220.0	4	10	5.0	26	115.	4.61	7.50

OPTIMUM SOLUTION

ANNUAL ADDITIONS: CAPACITY(MW) AND NUMBER OF UNITS OR PROJECTS

FOR DETAILS OF INDIVIDUAL UNITS OR PROJECTS SEE VARIABLE SYSTEM REPORT

SEE ALSO FIXED SYSTEM REPORT FOR OTHER ADDITIONS OR RETIREMENTS

0

NAME:				GTRB	CC#2	NGCC	CCFB	ORFS	MSDO	PFSM	HROR	HSTO
SIZE (MW):				38.	115.	115.	115.	115.	38.	115.	0.	0.
	%LOLP											
YEAR	MAINT	NOMNT	CAP									
2001	.953		0.									
2002	.186		0.									
2003	.272		115.		1							
2004	.845		0.									
2005	.522		38.	1								
2006	.325		38.	1								
2007	.634		0.									
2008	.087		115.				1					
2009	.178		0.									
2010	.358		0.									
2011	.058		115.				1					
2012	.120		0.									
2013	.245		0.									
2014	.044		115.				1					
2015	.370		115.				1					
2016	.081		115.				1					
2017	.163		0.									
TOTALS			765.	2	1	0	5	0	0	0	0	0

SUMMARY OF
FIXED SYSTEM PLUS OPTIMUM SOLUTION
(NOMINAL CAPACITY (MW))

	THERMAL FUEL TYPE CAPACITIES										TOTAL CAP
YEAR	0	1	2	3	4	5	6	7	8	9	
	HFO	COAL	DISL	NATG	PETC	ORIM	****	****	****	****	
2001	467	0	177	0	0	0	0	0	0	0	645
2002	467	0	252	0	0	0	0	0	0	0	720
2003	467	0	271	0	0	0	0	0	0	0	738
2004	449	0	271	0	0	0	0	0	0	0	720
2005	449	0	309	0	0	0	0	0	0	0	758
2006	449	0	346	0	0	0	0	0	0	0	795
2007	449	0	346	0	0	0	0	0	0	0	795
2008	449	115	346	0	0	0	0	0	0	0	910
2009	449	115	346	0	0	0	0	0	0	0	910
2010	449	115	346	0	0	0	0	0	0	0	910
2011	449	230	346	0	0	0	0	0	0	0	1025
2012	449	230	346	0	0	0	0	0	0	0	1025
2013	449	230	346	0	0	0	0	0	0	0	1025
2014	449	345	346	0	0	0	0	0	0	0	1140
2015	289	460	346	0	0	0	0	0	0	0	1095
2016	289	575	346	0	0	0	0	0	0	0	1210
2017	289	575	346	0	0	0	0	0	0	0	1210

SUMMARY OF
FIXED SYSTEM PLUS OPTIMUM SOLUTION
(NOMINAL CAPACITY IN MW, ENERGY IN GWH)

	HYDROELECTRIC				TOTAL THERMAL	TOTAL	SYSTEM		ENERGY NOT SERVED
	HROR		HSTO		CAPACITY	CAP	RES.	LOLP.	HYDROCONDITION
YEAR	PR.	CAP	PR.	CAP			%	%	1
2001	7	11	0	0	645	656	21.9	.953	1.9
2002	7	11	0	0	720	731	29.6	.186	.3
2003	7	11	0	0	738	750	31.2	.272	.6
2004	7	11	0	0	720	732	23.7	.845	2.1
2005	7	11	0	0	758	769	25.7	.522	1.2
2006	7	11	0	0	795	807	27.3	.325	.7
2007	7	11	0	0	795	807	23.0	.634	1.5
2008	7	11	0	0	910	922	35.8	.087	.2
2009	7	11	0	0	910	922	31.2	.178	.4
2010	7	11	0	0	910	922	26.8	.358	.9
2011	7	11	0	0	1025	1037	37.8	.058	.2
2012	7	11	0	0	1025	1037	33.1	.120	.3
2013	7	11	0	0	1025	1037	28.6	.245	.7
2014	7	11	0	0	1140	1152	38.1	.044	.1
2015	7	11	0	0	1095	1106	28.1	.370	1.2
2016	7	11	0	0	1210	1221	36.7	.081	.3
2017	7	11	0	0	1210	1221	32.0	.163	.6

SUMMARY OF
FIXED SYSTEM PLUS OPTIMUM SOLUTION
0 EXPECTED GENERATIONS BY PLANT TYPE (GWH)

0 THERMAL FUEL TYPES

	HYDROELECTRIC			0	1	2	3	4	5	6	7	8	9		GR.
YEAR	HROR	HSTO	TOTAL	HFO	COAL	DISL	NATG	PETC	ORIM	****	****	****	****	TOTAL	TOTAL
2001	88	0	88	3072	0	200	0	0	0	0	0	0	0	3272	3360
2002	88	0	88	3148	0	286	0	0	0	0	0	0	0	3434	3522
2003	88	0	88	3013	0	600	0	0	0	0	0	0	0	3613	3701
2004	88	0	88	3015	0	727	0	0	0	0	0	0	0	3742	3830
2005	88	0	88	3065	0	811	0	0	0	0	0	0	0	3876	3964
2006	88	0	88	3106	0	910	0	0	0	0	0	0	0	4016	4104
2007	88	0	88	3138	0	1021	0	0	0	0	0	0	0	4159	4247
2008	88	0	88	2810	888	611	0	0	0	0	0	0	0	4309	4397
2009	88	0	88	2896	888	678	0	0	0	0	0	0	0	4462	4550
2010	88	0	88	2972	888	761	0	0	0	0	0	0	0	4621	4709
2011	88	0	88	2531	1765	491	0	0	0	0	0	0	0	4787	4875
2012	88	0	88	2631	1770	557	0	0	0	0	0	0	0	4958	5046
2013	88	0	88	2733	1773	627	0	0	0	0	0	0	0	5133	5221
2014	88	0	88	2329	2587	400	0	0	0	0	0	0	0	5316	5404
2015	88	0	88	1539	3385	581	0	0	0	0	0	0	0	5505	5593
2016	88	0	88	1314	4038	350	0	0	0	0	0	0	0	5702	5790
2017	88	0	88	1382	4095	427	0	0	0	0	0	0	0	5904	5992

D Y N P R O

SUMMARY OF CAPITAL COSTS OF ALTERNATIVES IN $/KW

PLANT	CAPITAL COSTS (DEPRECIABLE PART) DOMESTIC	CAPITAL COSTS (DEPRECIABLE PART) FOREIGN	INCLUSIVE IDC %	CONSTR. TIME (YEARS)	PLANT LIFE (YEARS)	CAPITAL COSTS (NON-DEPREC. PART) DOMESTIC	CAPITAL COSTS (NON-DEPREC. PART) FOREIGN
THERMAL PLANT CAPITAL COSTS							
GTRB	.0	638.8	6.47	.50	25.	.0	.0
CC#2	.0	964.3	13.45	2.00	25.	.0	.0
NGCC	.0	898.5	13.45	2.00	25.	.0	.0
CCFB	.0	1512.3	20.98	3.00	30.	.0	.0
ORFS	.0	1633.2	20.98	3.00	30.	.0	.0
MSDO	.0	1588.3	13.45	2.00	25.	.0	.0
PFSM	.0	1693.7	20.98	3.00	30.	.0	.0

1SOLUTION # 1 VARIABLE ALTERNATIVES BY YEAR

YEAR	PRESENT WORTH COST OF THE YEAR (K$) CONCST	SALVAL	OPCOST	ENSCST	TOTAL	OBJ.FUN. (CUMM.)	LOLP %	GTRB	CC#2	NGCC	CCFB	ORFS	MSDO	PFSM	HROR	HSTO
2017	0	0	26252	92	26344	2221278	.163	2	1	0	5	0	0	0	0	0
2016	21373	15084	28369	52	34711	2194934	.081	2	1	0	5	0	0	0	0	0
2015	24579	14545	34386	254	44674	2160223	.370	2	1	0	4	0	0	0	0	0
2014	28266	14006	50355	31	64646	2115549	.044	2	1	0	3	0	0	0	0	0
2013	0	0	60953	191	61144	2050903	.245	2	1	0	2	0	0	0	0	0
2012	**0**	**0**	**66807**	**104**	**66911**	**1989759**	**.120**	**2**	**1**	**0**	**2**	**0**	**0**	**0**	**0**	0
2011	42989	12390	73471	57	104127	1922848	.058	2	1	0	2	0	0	0	0	0
2010	0	0	91381	391	91772	1818721	.358	2	1	0	1	0	0	0	0	0
2009	0	0	99974	216	100190	1726949	.178	2	1	0	1	0	0	0	0	0
2008	65381	10774	109780	119	164506	1626759	.087	2	1	0	1	0	0	0	0	0
2007	0	0	140093	980	141073	1462253	.634	2	1	0	0	0	0	0	0	0
2006	11910	1158	153314	541	164607	1321181	.325	2	1	0	0	0	0	0	0	0
2005	13696	1069	168979	1048	182655	1156573	.522	1	1	0	0	0	0	0	0	0
2004	0	0	186387	2046	188434	973919	.845	0	1	0	0	0	0	0	0	0
2003	83852	4122	204539	664	284933	785485	.272	0	1	0	0	0	0	0	0	0
2002	0	0	237373	432	237806	500553	.186	0	0	0	0	0	0	0	0	0
2001	0	0	259895	2851	262747	262747	.953	0	0	0	0	0	0	0	0	

JPSCo's Demand Forecast 2003

1.0 Executive Summary

In April 2001 Mirant Incorporated acquired 80% of the government owned electric utility, Jamaica Public Service Company (JPSCo). This acquisition coincided with the introduction of an All-Island Electricity Licence which gives the Company the right to produce, distribute and retail electricity throughout the island.

Along with the right to supply electricity, the Licence delineates the company's responsibilities and the regulatory framework within which it operates. Chief among JPSCo's responsibilities is the mandate of ensuring that the service is adequate and efficient. In this respect serious long term planning is a critical for the company, if it is to do justice to its responsibility. Without careful planning there exist the distinct likelihood of over or under-investment, which has unfavorable implications for the price customers pay for supply or the quality of service experience in the country.

The JPSCo. 2003 demand forecast is presented in this paper. It covers the period 2003 –2020. The demand forecast employs econometric modeling as the principal technique in generating the results. In recognition of the uncertainty inherent in forecasting three scenarios were developed – the 'base' or normal forecast, the 'high' or optimistic forecast and the 'low" or pessimistic forecast.

In developing the forecast of the price of electricity, gross domestic product (GDP) and population growth were the socio-economic factors that were deemed essential to the models used. The models were applied to each customer class separately and the individual results aggregated to provide a global sales forecast. The demand (load) forecast for the system was derived by assuming that the relationship (load factor) between sales (kWh) and demand (KW) is a stable one.

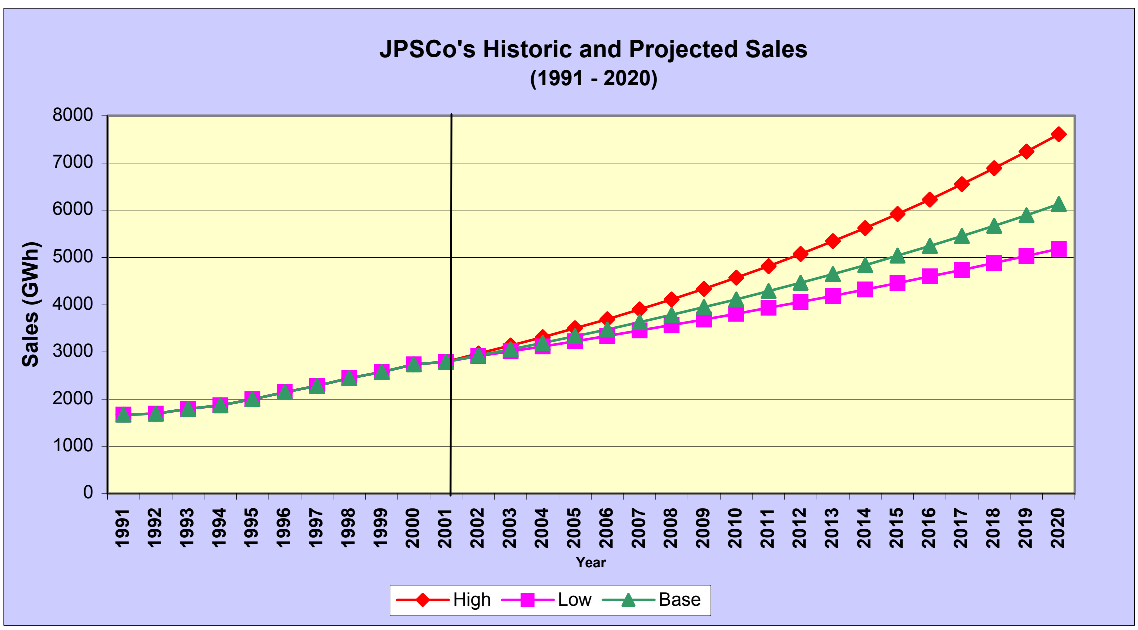
As a basis for the assumptions in the forecast the Bank of Jamaica's (BOJ's) 2002 medium term projection for the economy was assessed in the context of the prevailing economic milieu. Consequently, the assumptions employed, while not radically different from the BOJ's projections they are less optimistic in the base demand forecast. An annual economic growth rate of 3%, an inflation rate of 6%, and population expansion of 0.9% are assumed in the base forecast (see Table 1-1).

Table 1.1 Socio-economic Forecasting Assumptions

	Base	Low	High
Growth in Real GDP	3.0%	0.0%	6.0%
Inflation Rate	5.0%	7.0%	4.0%
Population Growth	0.9%	0.8%	1.0%

The result of the modeling was good and in most part the outcome satisfies the statistical criteria associated with sound econometrics. In all the models examined at more than 96% of variation in the demand for electricity could be explained of the socio-economic variables used.

Figure 1



Indications from the forecast are that over the next 20 years, it is reasonable (the base forecast) to envisage an annual increase in the sales of 4.5%; it is pessimistic (the low forecast) to expect 3.3% annual sales growth, and the prospect of a 5.4% sales growth each year is optimistic (see Table 1-2).

Table 1.2 Annual Sales Projections (GWh) for Period 2002 – 2020

Forecast	2002	2003	2004	2005	2006	2007	2010	2015	2020	Annual Growth
Base	2,925	3,054	3,190	3,331	3,477	3,628	4,113	5,037	6,128	**4.5%**
High	2,970	3,136	3,314	3,500	3,694	3,898	4,570	5,918	7,610	**5.4%**
Low	2,910	3,011	3,118	3,226	3,338	3,451	3,808	4,458	5,181	**3.3%**

2.0 Background

In recent time there have been two changes in the national electricity industry, which has had a significant impact on the JPSCo's orientation to business. The first was the strengthening of the regulatory framework through an amendment to the Office of Utilities Regulation (OUR) Act in 2000 and the introduction of an All-Island Electricity Licence in 2001. The amendment to the Act in 2000 expanded the scope of OURs regulatory authority and the Licence even went further by clearly setting the rights and responsibility of the utility. Together these legal instruments have provided the OUR a better framework for balancing the concerns of customers with the objectives of the utility. Secondly, Mirant Incorporated acquired 80% of the government owned company in 2001. Consequently, effective control of the company was moved from the public to the private sector.

With these two developments consumers' expectation with respect to the quality of service have been raised, the debilitating constraints on capital investment has been removed and the investors are clear on the level of return they anticipate from their investment. It is therefore in this context, that the exercise of demand forecasting assumes enormous importance. The demand forecast, which serves as guide to the company's investment of the medium and long term, must therefore reflect a fair degree of accuracy if over-investment or under-investment is to be avoided. Over-investment leads to superfluous capacity, which consumers pay for by way of higher rates. On the other hand, under-investment causes inadequacy of supply, which inevitably results in blackout that retards economic development and impairs the quality of life experienced. In addition, an under-investment results in less revenue and reduced profits.

3.0 Methodology

There are three main approaches to demand forecasting; Trend Analysis, Econometric modeling and the End-use technique. The main difference between the first two approaches and the End-use technique is that they rely heavily on historical data. On the other hand, the End-use approach emphasizes the current conditions. In deriving the demand forecast a combination of the Econometric modeling and Trend Analysis was employed.

Econometric modeling was the dominant technique used and this is associated with the fact that:

1. Unlike the End-use model which requires considerable field research and primary data collection the information used in this technique easily available.
2. When compared to End-use approach data gathering is relatively in expensive.
3. Over the years the JPSCo forecast derived from this technique has been deemed to be very accurate.

The econometric technique was used in developing the forecast for all electricity classes except Street lights. Unlike other customer categories the demand for Street lighting tends to grow in an arithmetic progression. Consequently, the Simple Trend Analysis was deemed more appropriate.

3.1 Residential and Industrial Model

For the Residential and Commercial/Industrial classes two basic forecasting models were constructed. In the first, demand was considered a log-linear function of the price of electricity, Gross Domestic Product (GDP) and the number of customers. In the second, the number of customers was deemed to grow linearly as population increases. The specification for these functions are given by:

$$D_t = a + b_1 \ln P_t + b_2 \ln Y_t + b_3 \ln C_t + e_t \quad \text{.......(1)}$$

$$C_t = d + e\, G_t + e_t \quad \text{.......(2)}$$

Where:

- D_t = Sales in MWH
- P_t = Average real price of electricity
- Yt = Real GDP of the sector
- C_t = Number of Customers
- G_t = Population
- e_t = Random error component
- .t = time

These models were applied separately for each rate class (RT10, RT20, RT40 & RT50). The global forecast was derived from the aggregate of the results of the individual classes along with the forecast for the streetlight category.

3.2 Streetlight Model

Streetlight demand may be best considered a variable explained purely as a function of time. Modeling this demand therefore does not include economic, demographic and political policy variable, rather it is just a function of time. The function was therefore specified to be:

$$D_t = k + m(t_n - t_0) \quad \text{...........(3)}$$

Where:

- D_t = Sales in MWH
- t_n = the Nth time period
- t_0 = the base time period

4.0 Regression Results

Using data spanning the period 1981 to 2001 the Residential and Commercial/Industrial models (see equations 1& 2) were fitted applying multiple linear regression technique. The result for each customer category is presented below.

Table 4-1 Residential (Rate 10) Regression Output

Variable	Symbol	Coefficient	Std. Error	t-Statistic	Prob.
Intercept	C	-6.127354	0.685014	-8.944865	0.00000
Price	lnP_t	-0.134497	0.049481	-2.718149	0.01460
Income	lnY_t	0.138179	0.071732	1.926323	0.07100
No. of Cust	lnC_t	1.503726	0.04592	32.7466	0.00000
Adj. R-Squared	Adj. R^2	0.992113			
Durbin-Watson Stat	D-W	1.401936			

Table 4-2 Small Commercial (Rate 20) Regression Output

Variable	Symbol	Coefficient	Std. Error	t-Statistic	Prob.
Intercept	C	0.7338	0.8208	0.8940	0.3864
Price	lnP_t	-0.1436	0.0447	-3.2132	0.0063
Income	lnY_t	0.1728	0.0645	2.6775	0.0180
No. of Cust	lnC_t	1.0050	0.0812	12.3783	0.0000
Adj. R-Squared	Adj. R^2	0.989019			
Durbin-Watson Stat	D-W	2.353707			

Table 4-3 Small Industrial (Rate 40) Regression Output

Variable	Symbol	Coefficient	Std. Error	t-Statistic	Prob.
Intercept	C	3.657156	0.848926	4.307979	0.001
Price	lnP_t	-0.158414	0.038194	-4.1476	0.0014
Income	lnY_t	0.05699	0.058802	0.969189	0.3516
No. of Cust	lnC_t	1.306848	0.113237	11.54084	0.0000
Adj. R-Squared	Adj. R^2	0.965512			
Durbin-Watson Stat	D-W	2.42183			

Table 4-4 Large Industrial (Rate 50) Regression Output

Variable	Symbol	Coefficient	Std. Error	t-Statistic	Prob.
Intercept	C	9.07503	0.816857	9.611782	0.0000
Price	$\ln P_t$	-0.035004	0.040831	-0.48977	0.6319
Income	$\ln Y_t$	0.052426	0.077644	2.444859	0.02840
No. of Cust	$\ln C_t$	0.68227	0.023649	26.13487	0.0000
Adj. R-Squared	Adj. R^2	0.99061			
Durbin-Watson Stat	D-W	1.600939			

4.1 Goodness of Fit

In all the classes the regression fits were good. The adjusted coefficient of determination ranged from 0.9655 for the Small Industrial class to 0.9920 for the Residential class indicating that the variables (real electricity price, real GDP and the number of customers) employed in the models explains at least 96.55% of the variation in demand for electricity.

4.2 Elasticities

As in all log-linear regression model the coefficients represents the respective elasticties. Theoretically, it is reasonable to expect demand to decrease when price rises and increase with the growth of GDP or the expansion of the customer base. In this respect the models lived up to expectations (see Table 4.5) as in all instances the signs of the coefficients are consistent with theory.

Table 4-5 Elasticities of Demand

Elasticities	RT10	RT20	RT40	RT50
Price	-0.1345	-0.1436	-0.1584	-0.0350
Income	0.1382	0.1728	0.0570	0.0524
Customer	1.5037	1.0050	1.3068	0.6823

Not only were the signs of coefficients in line with expectations, but the same was true for the magnitudes of the elasticities. Both the price and income coefficients were are inelastic, while customer additions (except for RT50) turned out to be relatively elastic.

4.3 Price Elasticity of Demand

Interestingly, there seems to be very little difference in the responsiveness of demand in the RT10, RT20 and RT40 categories to price movements, with coefficients of –0.13,

-0.14 and –0.16. Of course, as is the case in most electricity markets worldwide the Residential group is the least responsive of the three categories.
For the Large Industrial group (RT50), however, the demand is extremely price inelastic at –0.04. It may be argued that because a significant component of the hotel sector falls in this group, prices tend to have little effect on consumption since:

1. the usage is more driven by the needs of tourist rather than the inclination to conserve;

2. large hotels operate at a fairly sophisticated level relative to other sectors in the economy. In this context, the benefits to be gained from energy efficient equipment and supply configuration, in response to price increases tend to be small.

4.4 Income Elasticity of Demand

The income elasticities for the Residential and the Small Commercial classes are more responsive to movement in income than the other two classes. This is not surprising since the Small Commercial class consists of mostly shops and small producers whose goods and services are mainly directed to the domestic market. And what happens with regards to the consumption of goods and services in the domestic market is largely determined by the income of the residential sector.

In contrast RT10 and RT20 customer classes, the Small Industrial class and the Large Industrial class have relatively weak linkages with the domestic economy. This is associated with the fact that there is greater emphasis on tourism and commodity export in these classes. Consequently, it seems plausible to assume that the responsiveness of the demand for electricity is more related to conditions in the global economy (the US in particular) rather than the domestic economy. Therefore it is no surprise their income elasticities as it relates to real GDP is extremely low (0.06 and 0.05 for RT40 and RT50 classes respectively).

4.5 Customer Elasticity of Demand

Except for the Large Industrial (RT50) category, the demand associated with customer addition is elastic. The evidence seems to suggest that customer addition to this category is generally small owing to the degree of risk associated with these businesses and the high start up capital required. In addition, new entrants in this category tend to place a relative higher premium on efficiency, as result the latest technology available is often employed allows them to minimize operating cost. Consequently, customer elasticity of demand is low (0.68).

4.6 Significance of the Variables

In general the variables, notably the number of customer, in the models came out to be significant at the 5% level and lower. The exceptions were GDP for the Residential and Small Industrial groups with significance levels of 7% and 35% respectively.

The significance level registered by the Residential can be explained by the presence of the informal sector. The informal sector encompasses economy activities outside of the mainstream economy, which eludes quantification spanning petty traders on the sidewalk to clandestine narcotic business. The influence of the informal sector nonetheless dilutes the significance of the formal economy causing GDP to less important in estimating the Residential demand.

In the case of the Small Industrial GDP is not significant because of the composition of the class. The Rate 40 group contains a fairly large number of irrigation and water supply pumps as well as many government offices. It therefore may be argued that for these customers output is driven more by the essential nature of the services offered and has very little relationship with real economic activities.

5.0 Economic Review and Outlook

In 2001 the Jamaican economy grew by 1.7%, the second consecutive year of positive growth after four continuous years of recession. Growth was achieved in 2001 despite three shocks the economy suffered.

First, there was an outbreak of violence in Western Kingston in July. This resulted in adverse international publicity and a fall off in tourist arrivals. Then there was the September 1, 2001 terrorist attack in the US, which inflicted another blow to the flagging tourist industry and triggered further contraction in the world economy. Finally, a turbulent hurricane season resulted in massive flooding, enormous infrastructure damage and created havoc in the fragile agricultural sector. It has been posited that outside of these shocks the economy would have grown in the region of 3% during 2001.

The 8.7% inflation in 2001, although representing the fifth consecutive year of single digit inflation, exceeded the 2000 level by 1.6%. The higher than expected inflation has been largely attributed to significant price increases in transportation sector in the middle of the year and the speeding up of the deterioration of the exchange rate with the slowing down of foreign currency inflows.

Based on the Bank of Jamaica's (BOJ's) medium term forecast the economy is expected to show an average growth of 3 – 5% over the next three years with tourist, mining, agriculture and financial sectors being the main contributors. On the strength of the country's monetary policies and fiscal discipline on the part the government, it is projected that inflation will be contain within the region of 5% over the medium term.

6.0 Modeling Assumptions

In developing the forecast four variables are critical the projections; growth in real GDP, the inflation rate, real increase in electricity prices and the rate of population growth. JPSCo came up with the trajectory for the variables based on historical tempered by the BOJ outlook. The main economic assumptions used in the model are shown in Table 6-1.

Table 6-1 Demand Forecast Assumptions

	Base	Low	High
Growth in Real GDP	3.0%	0.0%	6.0%
Inflation Rate	5.0%	7.0%	4.0%
Population Growth	0.9%	0.8%	1.0%
Tariff Increase	3.0%	5.0%	1.0%

6.1 Gross Domestic Product

The lower limit (3%) of the BOJ's GDP projection was the assumed in company's base forecast. The dynamics between the real and financial sectors of the economy are inverted, with the considerable higher rate of returns in the financial sector relative to the real sector. This contravenes economic fundamentals since risk free financial instruments provide higher return than risky real sector investments. Consequently, there is a measure of inertia within the economy that makes the upper end of the BOJ's projection excessively optimistic.

6.2 Inflation Rate

The inflation rate assumed in base demand forecast is 5% per annum. By assuming the upper limit of the BOJ's GDP forecast this adjustment had to be made to their corresponding 5% inflation projection. A lower level of growth means a less favorable balance of trade, which has exchange rate implications. It is expected that this in turn will lead to an inflation level slightly above the BOJ's forecast.

6.3 Tariff Rate

A 3% annual increase is assumed in real tariff in keeping with the expected growth in the economy.

6.4 Population Growth

Based on the trend over the period 1992 – 2000, the population was assumed to increase at a rate of 0.9 % each year.

7.0 Forecast

Arising from the structure of the model and the assumptions made JPSCo's sales growth over the next 20 years is projected at the rate of 4.5%, 5.4% and 3.3% for the base, high and low cases respectively. The results are captured in Tables 7-1 to 7-4.

Table 7.1 Base Forecast –Annual

Year	Customer	Sales	Generation	Peak Demand
		MWh	MWh	MW
2002	506,590	2,925,005	3,524,103	583.0
2003	523,896	3,053,631	3,679,073	608.7
2004	541,350	3,190,060	3,843,446	635.9
2005	558,951	3,331,202	4,013,497	664.0
2006	576,703	3,477,206	4,189,405	693.1
2007	594,605	3,628,227	4,371,358	723.2
2008	612,659	3,784,425	4,559,548	754.3
2009	630,866	3,945,962	4,754,171	786.5
2010	649,229	4,113,010	4,955,434	819.8
2011	667,747	4,285,742	5,163,545	854.3
2012	686,423	4,464,339	5,378,722	889.9
2013	705,257	4,648,986	5,601,189	926.7
2014	724,251	4,839,876	5,831,176	964.7
2015	743,407	5,037,205	6,068,921	1,004.1
2016	762,726	5,241,176	6,314,670	1,044.7
2017	782,209	5,452,000	6,568,675	1,086.7
2018	801,857	5,669,893	6,831,197	1,130.2
2019	821,672	5,895,078	7,102,504	1,175.1
2020	841,656	6,127,784	7,382,872	1,221.4

Table 7.2 Optimistic (High) Forecast Results - Annual

Year	Customer	Sales	Generation	Peak Demand
		MWh	MWh	MW
2002	511,608	2,970,086	3,578,416	592.0
2003	532,018	3,136,173	3,778,522	625.1
2004	552,632	3,313,619	3,992,312	660.5
2005	573,451	3,499,552	4,216,328	697.6
2006	594,479	3,694,351	4,451,026	736.4
2007	615,717	3,898,413	4,696,883	777.1
2008	637,168	4,112,152	4,954,400	819.7
2009	658,833	4,335,998	5,224,095	864.3
2010	680,714	4,570,404	5,506,511	911.0
2011	702,814	4,815,839	5,802,216	959.9
2012	725,136	5,072,795	6,111,801	1,011.2
2013	747,680	5,341,782	6,435,882	1,064.8
2014	770,450	5,623,336	6,775,104	1,120.9
2015	793,447	5,918,014	7,130,137	1,179.6
2016	816,674	6,226,397	7,501,683	1,241.1
2017	840,134	6,549,092	7,890,472	1,305.4
2018	863,828	6,886,731	8,297,266	1,372.7
2019	887,759	7,239,975	8,722,861	1,443.1
2020	911,929	7,609,512	9,168,087	1,516.8

Table 7.3 Pessimistic (Low) Forecast -Annual

Year	Customer	Sales	Generation	Peak Demand
		MWh	MWh	MW
2002	506,558	2,910,280	3,506,362	580.1
2003	521,828	3,011,110	3,627,844	600.2
2004	537,213	3,117,542	3,756,074	621.4
2005	552,714	3,226,383	3,887,209	643.1
2006	568,330	3,337,680	4,021,302	665.3
2007	584,064	3,451,479	4,158,409	688.0
2008	599,916	3,567,828	4,298,588	711.2
2009	615,886	3,686,774	4,441,897	734.9
2010	631,977	3,808,367	4,588,395	759.1
2011	648,187	3,932,658	4,738,142	783.9
2012	664,520	4,059,697	4,891,201	809.2
2013	680,975	4,189,536	5,047,634	835.1
2014	697,553	4,322,230	5,207,506	861.5
2015	714,256	4,457,832	5,370,881	888.6
2016	731,083	4,596,397	5,537,827	916.2
2017	748,037	4,737,981	5,708,411	944.4
2018	765,119	4,882,643	5,882,702	973.2
2019	782,328	5,030,441	6,060,772	1,002.7
2020	799,666	5,181,433	6,242,691	1,032.8

Table 7.4 Base Forecast -Monthly

Month	Sales (MWh)							Generation	Peak Demand
	Rate 10	Rate 20	Rate 40	Rate 50	Rate 60	Others	Total	(MWh)	(MW)
Jan-03	108,059	56,421	49,483	40,245	4,622	648	**259,478**	312,624	575.9
Feb-03	91,847	50,446	48,111	38,143	4,620	648	**233,816**	281,706	575.3
Mar-03	91,670	51,707	51,140	37,830	4,641	648	**237,637**	286,310	589.8
Apr-03	98,286	56,106	53,126	38,413	4,778	648	**251,358**	302,840	593.0
May-03	92,850	54,085	53,438	43,770	4,734	648	**249,526**	300,634	596.3
Jun-03	100,794	59,459	54,113	41,864	4,784	648	**261,662**	315,255	596.4
Jul-03	102,414	58,687	55,882	42,881	4,783	648	**265,295**	319,633	600.3
Aug-03	108,039	62,898	59,617	44,645	4,791	648	**280,640**	338,120	610.2
Sep-03	99,168	57,973	52,910	42,273	4,756	648	**257,727**	310,515	611.0
Oct-03	100,366	58,412	53,167	42,177	4,840	648	**259,610**	312,783	610.3
Nov-03	103,063	57,751	51,146	42,405	4,786	648	**259,800**	313,012	609.8
Dec-03	99,120	54,240	49,058	40,889	4,787	648	**248,742**	299,689	610.2
Jan-04	115,145	59,017	51,062	40,770	4,668	648	**271,310**	326,880	601.6
Feb-04	97,870	52,768	49,647	38,640	4,666	648	**244,240**	294,265	600.9
Mar-04	97,682	54,086	52,773	38,323	4,687	648	**248,200**	299,036	616.1
Apr-04	104,731	58,687	54,822	38,914	4,825	648	**262,629**	316,420	619.5
May-04	98,939	56,573	55,144	44,341	4,782	648	**260,427**	313,768	622.9
Jun-04	107,403	62,195	55,840	42,410	4,832	648	**273,328**	329,311	623.1
Jul-04	109,130	61,387	57,665	43,441	4,831	648	**277,102**	333,858	627.1
Aug-04	115,124	65,792	61,520	45,228	4,839	648	**293,152**	353,195	637.4
Sep-04	105,671	60,640	54,599	42,824	4,803	648	**269,186**	324,320	638.3
Oct-04	106,947	61,099	54,865	42,727	4,888	648	**271,174**	326,716	637.6
Nov-04	109,822	60,409	52,779	42,957	4,834	648	**271,449**	327,047	637.0
Dec-04	105,619	56,735	50,624	41,422	4,835	648	**259,884**	313,114	637.5