Office of Utilities Regulation

DETERMINATION OF THE ELECTRICITY

INDICATIVE GENERATION

AVOIDED COSTS

Parameters and Assumptions contained herein will be used for bid evaluations.

OUR
OFFICE OF UTILITIES REGULATION

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DETERMINATION OF THE ELECTRICITY INDICATIVE GENERATION AVOIDED COSTS

DESCRIPTION OF THE PROCESS

The electricity generation avoided cost figures were developed using the Wien Automatic System Planning (WASP) software tool. The process of determining the avoided generation costs consists of three main phases, which have to be implemented sequentially. The phases are:

1. **PREPARATION OF THE WASP INPUT DATA (i.e. Modeling JPS' Electricity Generation System)**
2. **PERFORMING SIMULATIONS IN WASP TO DETERMINE THE ECONOMIC OPTIMAL GENERAL EXPANSION STRATEGY**
3. **EXTRACTION OF DATA FROM WASP OUTPUT FILES TO DERIVE AVOIDED COST**

ECONOMIC OPTIMAL GENERATION EXPANSION STRATEGY

The economic optimal generation expansion sequence, determined using the WASP program, is as follows:

1 x 60MW Medium Speed Diesel Plant in 2010
3 x 120MW Coal Fired Steam Plants in 2013
1 x 120MW Coal Fired Steam Plants in 2015
1 x 120MW Coal Fired Steam Plants in 2021
1 x 120MW Coal Fired Steam Plants in 2025
1 x 60MW Medium Speed Diesel Plant in 2027

Refer to WASP Simulation output in Appendix below for more details.

Note that the following plants are also expected to be added to the system:

1 x 82MW Petcoke Cogeneration Plant in 2013

1 x 60MW Coal Based Cogeneration Plant in 2013

The cogeneration plants were inputted into the WASP simulation as committed plants; hence their schedules were not determined by the WASP optimization process.

COMPUTATION OF THE AVOIDED ELECTRICITY GENERATION COSTS

There are two scenarios in which generating plants can contribute to an electricity grid. They can provide:

1. Energy (electricity) plus a Firm Generating Capacity; or
2. Energy (electricity) only;

In the later case, the generating plants will not necessarily cause the deferment or replacement of expected future plant additions. On the other hand, generating plants of significant combined capacity will ultimately result in the deferment or replacement of future plant additions. This occurrence has resulted in a difference in the way the avoided cost is computed for both scenarios.

In the energy plus firm capacity scenario, the avoided cost is based solely on the expected future generating plants (which would be deferred or replaced), while for the energy only case, the avoided cost is based on the operations of both the existing and the expected plants to be added in the future.

Avoided Cost Components

The avoided electricity generation cost consists of two components, which relates to the following principal cost causation components:

1 **Energy**: cost which varies with the consumption of energy (variable cost, mostly fuel, but also includes variable O&M costs)

2 **Capacity**: cost which varies with the capacity requirements of the customers (fixed cost of generation investments, plus fixed O&M costs).

In the case of generating facilities that provide energy only, the capacity component of the avoided generation cost is not applicable.

In line with the foregoing, the avoided costs figures in the OUR's "Declaration of Indicative Avoided Generation Costs," were computed using the following formulas:

<u>For Generating Facilities that provide ENERGY only</u>

$$Avoided\ Cost = \frac{\sum_{i=1}^{n} (Fuel\ Cost_i + Variable\ O\&M_i)}{\sum_{i=1}^{n} Energy_i}$$

Where

i = ith power plant in the electricity grid (relates to the present worth figure)

n = the total number of power plants (inclusive of existing and future additions)

For Generating Facilities that provide ENERGY plus a FIRM GENERATING CAPACITY

Avoided Energy Cost = { (Sum of all the present worth Fuel and Variable O&M costs of the expected future plant additions)/(Sum of all the present worth energies from the expected future plant additions)}

Avoided Capacity Cost = { (Sum of all the present worth Capital costs less salvage and the Fixed O&M costs of the expected future plant additions)/(Sum of all the present worth energies from the expected future plant additions)}

SUMMARY OF THE INPUT PARAMETERS

Load Forecast

The load forecast, which is the term used to collectively represent both the energy and peak demand (load) projections, is a very important input in the generation expansion planning process, as it strongly influences the future generation capacity requirements and their schedules. The peak demand and energy projections utilized in the study are shown in Table 1.0. It was assumed that the system's peak demand and energy would grow at an average of 2.5% per annum over the next 20 years.

Year	Peak Demand (MW)	Energy (GWh)
2008	645.1	4,425
2009	661.3	4,536
2010	677.8	4,649
2011	694.7	4,766
2012	712.1	4,885
2013	729.9	5,007
2014	748.2	5,132
2015	766.9	5,260
2016	786.0	5,392
2017	805.7	5,527
2018	825.8	5,665
2019	846.5	5,806
2020	867.6	5,952
2021	889.3	6,100
2022	911.6	6,253
2023	934.3	6,409
2024	957.7	6,569
2025	981.6	6,734
2026	1006.2	6,902
2027	1031.3	7,075
2028	1057.1	7,251

Table 1.0: Peak Demand and Energy Projections

Load Profile

The JPS system has a fairly consistent daily load pattern on weekdays and weekends, which are shown in Figures 1.0 and 1.1 respectively. For long time periods, it is convenient to represent load profiles in forms known as load duration curves (LDCs) (see Figure 1.2). The system's LDCs, which are also important inputs to the generation planning exercise, were developed from recent chronological load data submitted by JPS.

It can be computed from Table 1.0 that the annual system load factor used in the study was 78.31%. This load factor resulted from applying a modified JPS system load profile for the period April 2007 to March 2008. The modification to JPS system load profile involved normalizing the instances in which the load data reflected the connection of a limited load to the electric grid due to the effect of hurricane.

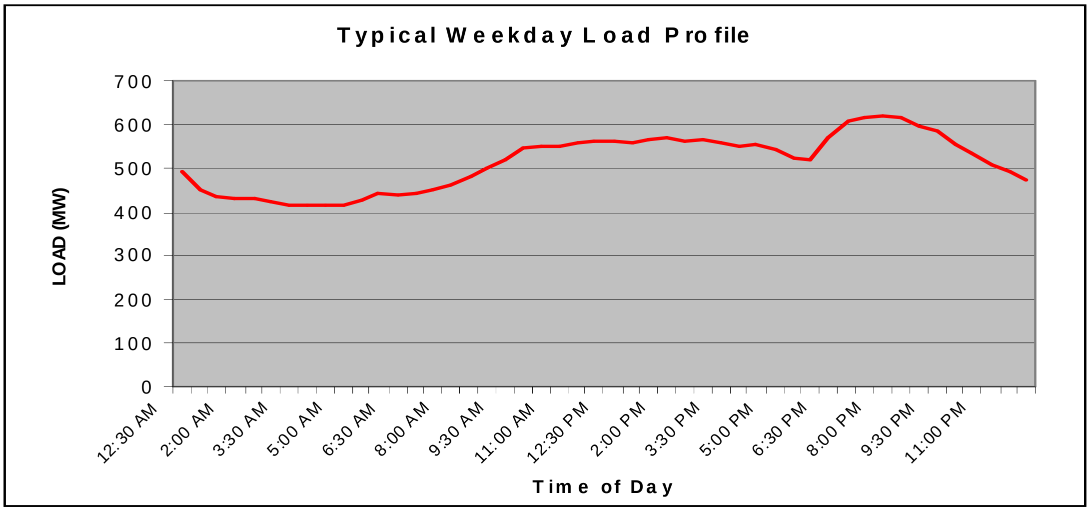

Figure 1.0: Typical Weekday Demand Pattern

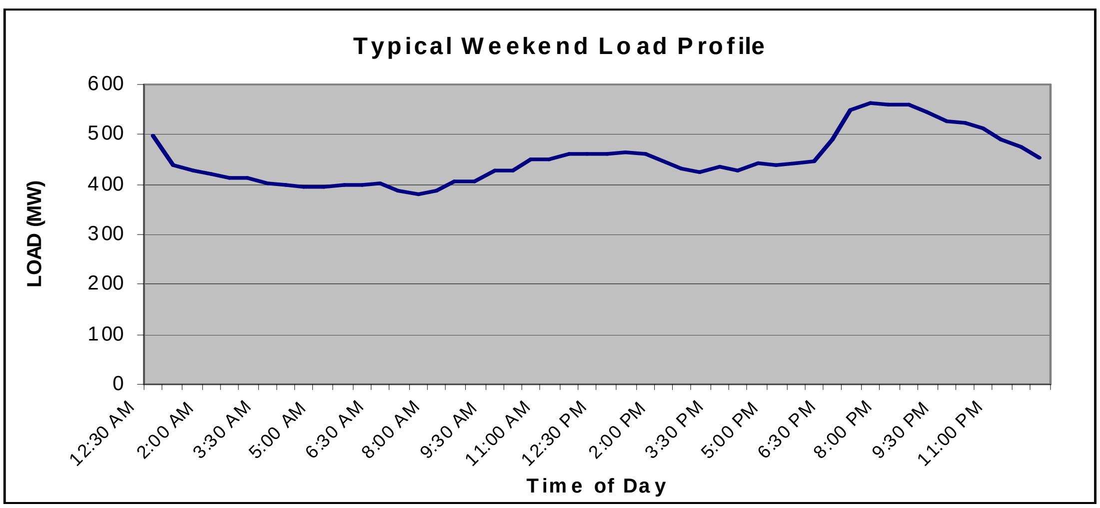

Figure 1.1: Typical Weekend Demand Pattern

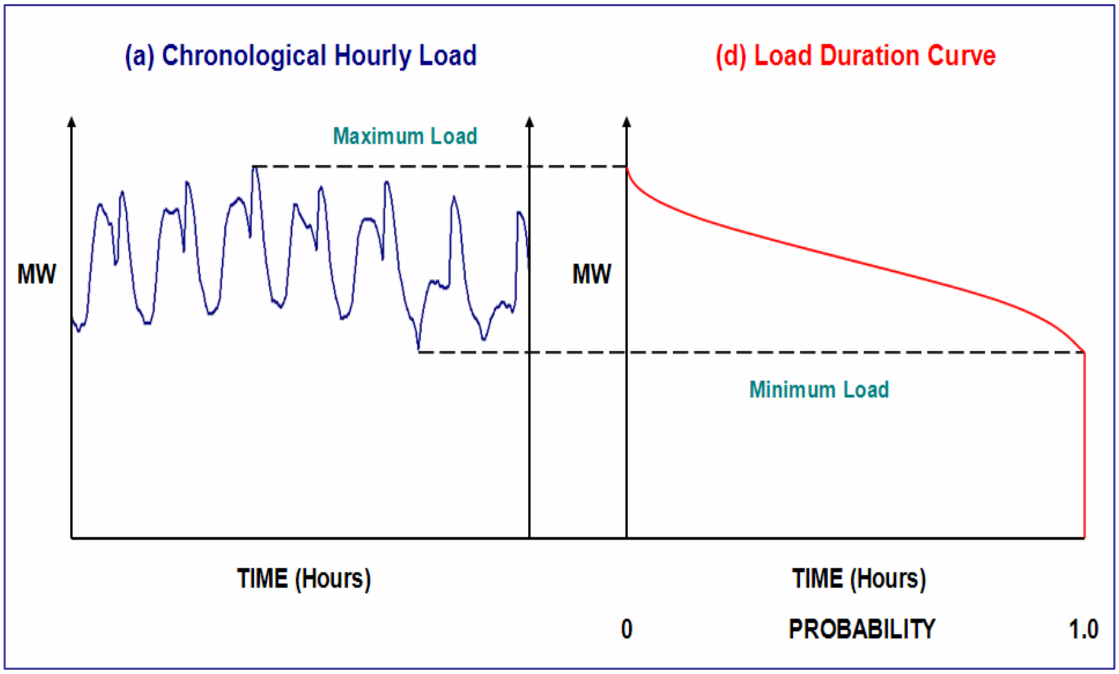

Figure 1.2: "Representation of the Load of an Electricity System: *(a) Chronological Hourly Load, (d) Load Duration Curve"*

Important Characteristics of the Existing Generating Plants

Table 1.1 below gives the important characteristics of the existing renewable energy technologies (RET) that were modeled in the study, while Table 1.2 gives a detailed outline of the capabilities and performance characteristics of the individual thermal generating units in the system.

Renewable Energy Technology	Installed Capacity (MW	Expected Annual Energy Contribution (GWh)
Hydroelectric	21.5	162.3
Wind	20.7	55.4

Table 1.1: Important Characteristics of the existing RET

Unit	**Description**	**Fuel**	**Gross Capacity** (MW)	**Planned Outage Days**	**Forced Outage Rate** (%)	**Approx. Availability** (%)	**Net Heat Rate at Max. Capacity** (kJ/kWh)	**Electrical Efficiency at Max. Capacity** (%)	**Variable O&M Cost** (US$/ MWh)	**Fixed O&M Cost** (US$/KW-month)	**In Service Date**	**Age (Yrs)**
OH1	Oil Fired Steam	HFO	30.0	28	8.0%	85%	15,515	23.2%	6.70	0.75	1968	40
OH2	Oil Fired Steam	HFO	60.0	28	8.0%	85%	14,675	24.5%	6.70	0.38	1970	38
OH3	Oil Fired Steam	HFO	65.0	28	8.0%	85%	12,757	28.2%	6.70	0.35	1972	36
OH4	Oil Fired Steam	HFO	68.5	28	8.0%	85%	12,713	28.3%	6.70	0.33	1973	35
HB6	Oil Fired Steam	HFO	68.5	28	8.0%	85%	12,758	28.2%	6.70	0.33	1976	32
RF1	Low Speed Diesel	HFO	18.0	38	5.0%	85%	9,613	37.5%	8.00	0.93	1985	23
RF2	Low Speed Diesel	HFO	18.0	38	5.0%	85%	9,613	37.5%	8.00	0.93	1985	23
GT3	Combustion Turbine	ADO	21.5	38	5.0%	85%	14,426	25.0%	5.00	0.39	1973	35
GT5	Combustion Turbine	ADO	21.5	38	5.0%	85%	15,612	23.1%	5.00	0.39	1974	34
GT6	Combustion Turbine	ADO	14.0	19	5.0%	90%	17,148	21.0%	5.00	0.60	1990	18
GT7	Combustion Turbine	ADO	14.0	19	5.0%	90%	16,508	21.8%	5.00	0.60	1990	18
GT8	Combustion Turbine	ADO	14.0	19	5.0%	90%	16,751	21.5%	5.00	0.60	1992	16
GT9	Combustion Turbine	ADO	20.0	19	5.0%	90%	14,507	24.8%	5.00	0.42	1992	16
GT10	Combustion Turbine	ADO	32.5	38	5.0%	85%	13,198	27.3%	5.00	0.26	1993	15
GT11	Combustion Turbine	ADO	20.0	19	5.0%	90%	12,819	28.1%	5.00	0.42	2001	7
BOCC	Combine Cycle	ADO	120.0	26	3.0%	90%	8,447	42.6%	6.00	0.99	2003	5
JPPC1	Slow Speed Diesel - **(IPP)**	HFO	30.0	26	3.0%	90%	8,080	44.6%	112.1	30.65	1996	12
JPPC2	Slow Speed Diesel - **(IPP)**	HFO	30.0	26	3.0%	90%	8,080	44.6%	112.1	30.65	1996	12
JEP1	Medium Speed Diesel - **(IPP)**	HFO	74.1	23	4.0%	90%	8,205	43.9%	124.9	18.51	1995	13
JEP2	Medium Speed Diesel - **(IPP)**	HFO	50.2	23	4.0%	90%	8,205	43.9%	124.9	18.51	2006	2
ALCO	Combine Heat & Power - **(IPP)**	HFO	5.0	19	5.0%	90%	-	-	84.0	15.00	-	-

Table 1.2: Capabilities and Performance Characteristics of the existing Thermal Generating Plants

Important Characteristics of the Future Candidate Generating Plants

Table 1.3 below gives the important characteristic of the future candidate thermal generating plants.

Plant Type	**Fuel Type**	**Plant Capacity** (MW)	**Planned Outage days**	**Forced Outage Rate** (%)	**Net Heat Rate at Max. Capacity** (kJ/kWh)	**Thermal Efficiency at Max. Capacity** (%)	**Variable O&M Cost** (US$/MWh)	**Fixed O&M Cost** (US$/KW-month)
Coal Fired Steam	Coal	120	26	5.0	9,729	37.0	7.0	2.48
Combined Cycle	Natural Gas	120	26	3.0	8,090	44.5	3.0	0.99
Combine Cycle	ADO	120	26	3.0	8,090	44.5	3.0	0.99
Combustion Turbine	Natural Gas	60	18	3.0	9,867	36.5	1.50	0.37
Combustion Turbine	ADO	60	18	3.0	9,867	36.5	1.50	0.37
Medium Speed Diesel	HFO	60	18	3.0	8,200	43.9	1.50	0.37

Table 1.3: Capabilities and Performance Characteristics of the Future Candidate Thermal Generating Plants

Characteristic of the Committed Generating Plants

In the study it was assumed that two cogeneration plants would be commissioned in 2013. The plants included a 100MW capacity Petcoke cogeneration plant exporting 82MW net to the grid, and a coal based cogeneration plant exporting 60MW net to the grid. The table below gives the performance characteristics of the committed generating plants.

Plant Type	**Fuel Type**	**Net Export to Grid** (MW)	**Planned Outage days**	**Forced Outage Rate** (%)	**Net Heat Rate at Max. Capacity** (kJ/kWh)	**Electrical Efficiency at Max. Capacity** (%)	**Variable O&M Cost** (US$/MWh)	**Fixed O&M Cost** (US$/KW-month)
Petcoke Fired Steam Cogen	Petcoke	82	26	5.0	9,850	36.5	7.0	2.48
Coal Fired Steam Cogen	Coal	60	26	5.0	10,000	36.0	7.0	2.48

Table 1.4: Capabilities and Performance Characteristics of the Committed Thermal Generating Plants

Fuel Costs

The table below gives the respective fuel costs assumptions that were made in the study.

FUEL TYPE	**Average Price at Plant Sites over the period 2008 to 2028**
Coal	US$110/tonne **(US$4.16/MBtu)**
Natural Gas	US$11.00/MBtu
Residual Oil (No. 6)	US$74.75/Bbl to US$76.29/Bbl **(US$11.89/MBtu to US$12.13/MBtu)**
Distillate Oil (No. 2)	US$121.67/Bbl to US$122.31/Bbl **(US$20.89/MBtu to US$21.00/MBtu)**
Petcoke	US$3.56/MBtu

Capital Costs

The following capital costs were used in the study for the respective technologies:

Petcoke Fired Steam Cogeneration Plant: US$3,300/KW (Inclusive of Interest During Construction)
Coal Fired Steam Cogeneration Plant: US$3167/KW (Inclusive of IDC and coal port infrastructure cost)
Coal Fired Steam Plant: US$3478/KW (Inclusive of IDC and coal port infrastructure cost)
Combined Cycle Plant (operating on NG or ADO): US$1383/KW (Inclusive of IDC)
Combustion Turbine (operating on NG or ADO): US$789/KW (Inclusive of IDC)
Medium Speed Diesel Plant: US$1550/KW (Inclusive of IDC)

APPENDIX:

WASP Simulation Output - Optimal Generation Expansion Sequence over the 20 year planning Horizon

YEAR	PRESENT WORTH COST OF THE YEAR (K$) CONCST	SALVAL	OPCOST	ENSCST	TOTAL	OBJ.FUN. (CUMM.)	LOLP %	PFC	NGCC	GT	OFCT	MSD	BCC	MSG	OFCC
2008	0	0	578560	1414	579974	579974	0.302	0	0	0	0	0	0	0	0
2009	0	0	533635	1664	535299	1115274	0.383	0	0	0	0	0	0	0	0
2010	76531	2133	466608	438	541444	1656718	0.122	0	0	0	0	1	0	0	0
2011	0	0	431236	743	431979	2088697	0.218	0	0	0	0	1	0	0	0
2012	0	0	398935	1247	400183	2488880	0.389	0	0	0	0	1	0	0	0
2013	710464	54083	150847	12	807240	3296119	0.007	3	0	0	0	1	0	0	0
2014	0	0	141635	23	141659	3437778	0.012	3	0	0	0	1	0	0	0
2015	188792	20603	111693	11	279893	3717671	0.007	4	0	0	0	1	0	0	0
2016	0	0	104615	20	104635	3822306	0.012	4	0	0	0	1	0	0	0
2017	0	0	98140	39	98179	3920485	0.022	4	0	0	0	1	0	0	0
2018	0	0	92149	68	92217	4012702	0.037	4	0	0	0	1	0	0	0
2019	0	0	86650	112	86762	4099464	0.062	4	0	0	0	1	0	0	0
2020	0	0	81588	179	81767	4181231	0.106	4	0	0	0	1	0	0	0
2021	95648	28329	64997	17	132333	4313564	0.016	5	0	0	0	1	0	0	0
2022	0	0	60871	33	60904	4374468	0.029	5	0	0	0	1	0	0	0
2023	0	0	57083	58	57141	4431609	0.050	5	0	0	0	1	0	0	0
2024	0	0	53633	97	53730	4485339	0.086	5	0	0	0	1	0	0	0
2025	60786	33480	45266	241	72813	4558152	0.212	6	0	0	0	1	0	0	0
2026	0	0	42561	375	42937	4601088	0.366	6	0	0	0	1	0	0	0
2027	11146	8175	39004	179	42154	4643242	0.198	6	0	0	0	2	0	0	0
2028	0	0	36697	286	36983	4680225	0.346	6	0	0	0	2	0	0	0

CONCST: Construction Cost
SALVAGE: Salvage Value
OPCOST: Operational Cost
ENSCST: Energy Not Served Cost
LOLP: Loss of Load Probability
PFC: Coal (pulverized) Fired Steam Plant
NGCC: Natural Gas Combined Cycle Plant
GT: Gas Turbine (Singe Cycle)
OFCT: Oil Fired Combustion Turbine
MSD: Medium Speed Diesel Plant
BCC: Biomass Combined Cycle
MSG: Medium Speed Gas Plant
OFCC: Oil Fired Combined Cycle