APPENDIX

30630022-Consulting 06-Draft

Setting of technical parameters for LRMC of CCGT
Initial draft report

Arnhem, 22 May 2006

Authors H. Koetzier, W. van der Veen, T.J. McInally (OnLine Energy Services)
KEMA Consulting Arnhem

By order of Energy Market Authority of Singapore

author : H. Koetzier		06-05-	reviewed	:	W. van der Veen	06-05-
B	44 pages 1 annexe		approved	:	R.J. Meier	06-05-

KEMA International B.V. Utrechtseweg 310, 6812 AR Arnhem P.O. Box 9035, 6800 ET Arnhem The Netherlands
T +31 26 3 56 91 11 F +31 26 3 89 24 77 contact@kema.com www.kema.com Registered Arnhem 09076333

CONTENTS

ABBREVIATIONS

ACG	Automatic Generation Control
b	Barrel (159 l)
CCGT	Combined cycle gas turbine
EMA	Energy market authority
EMC	Energy market company
FOB	Free on board
GSO	Gas system operator
HHV	Higher heating value
HSFO	High sulphur fuel oil
ISO	International standards organization
LDC	Load duration curve
LFO	Light fuel oil
LHV	Lower heating value
LRMC	Long run marginal cost
LTSA	Long term service agreement
MCE	Market clearing engine
MEUR	Million Euros
MSGD	Million Singapore dollars
MTI	Ministry of trade and industry
ORBP	OPEC reference basket price (the crude oil price)
PSO	Power system operator

SUMMARY

N.B. This report is Draft only for initial review, none of the figures or modelling results contained therein should be in any way construed as final or accurate at this stage. The document is released to provide Participants with feedback on our assumptions and approach and as a basis to refine our data.

KEMA have been engaged by the Energy Market Authority of Singapore to provide settings for the technical parameters used in the vesting contract computation for years 2007/8. These technical parameters are based on the development of a new efficient green field power plant referred to hereinafter as the Proxy plant. This Proxy plant should be of a technology that is already operational in Singpoare with a total installed capacity servicing at least 25% of the Singapore Electricity demand.

In order to evaluate these parameters KEMA have assumed a plant type which is of Combined Cycle Gas Turbine type “F”, an economic lifecycle of 20 years, and local conditions in Singapore. The total plant capacity chosen by KEMA is 800 MW_e (ISO Rated) in two trains of 400 MW^e each. The cost of the infrastructure, land, land preparation, impact of local ambient conditions, aging and relative construction costs in SE Asia have all been used in our computation of the parameters. Additionally, in order to validate the plant factor, we have used fundamental modelling to forecast the plant operation over the 20 year period of its lifecycle.

The first stage of the project was to introduce market participants to the KEMA approach to computation of the technical parameters and to take feedback therefrom. This we have done and the feedback is reported in the text of this document. The culmination of this stage is the document before you, which is the KEMA Initial draft report. Participants will be given the opportunity to review this report whence KEMA will hold a presentation and feedback session once again to ensure we have captured the participant input correctly. We will then re-run our computations based on agreed feedback and present a subsequent report for review.

1 INTRODUCTION AND METHODOLOGY

N.B. This report is Draft only for initial review, none of the figures or modelling results contained therein should be in any way construed as final or accurate at this stage. The document is released to provide Participants with feedback on our assumptions and approach.

The following statement (slightly adapted) taken from EMA's tender notice (a) serves very well as an introduction to this report: *The Energy Market Authority has implemented vesting contracts to curb the exercise of market power by the generation companies in the National Electricity Market of Singapore. The vesting contracts will commit the gencos to sell a specified amount of energy at a specified price (viz. vesting price) and thereby prevent the gencos from exercising their market power to drive up prices. The vesting price is set at the long-run marginal cost (LRMC) of the most efficient generation technology serving at least 25% of the total electricity demand. At this time the most efficient generation technology is the combined cycle gas turbine (CCGT). The vesting price is hence set at the long run marginal cost of the CCGT. The underlying concept of LRMC, as it has been determined, is to find the average price at which the most efficiently configured generation facility with the most economic technology in operation in Singapore will cover its variable and fixed cost and provide reasonable return to investors.*

1.1 Methodology

Thus the vesting price is the LRMC of a proxy plant. This proxy plant is:
- A green field plant constructed by a new industry player
- Using most efficient technology that currently serves at least 25% of the total Singapore electricity demand.

This report proposes initial draft settings for the technical LRMC parameters, being:
- Plant output on site @ 100% load
- Plant factor
- Yearly average heat rate
- Investment cost
- Build duration
- Fixed annual running cost
- Variable running cost (non fuel)
- Economic lifetime

1.2 Approach

KEMA follow the approach indicated by EMA that is:

1. Meet with the generation companies and electricity consumers to secure individually their views on how to set the technical LRMC parameters, and provide its assessment of those views. KEMA have met with Senoko, Seraya, Tuas, SembCorp, NERA, PCS, Keppel Merlimau, Island Power Company, Exxon

2. Show the assumpations and approch that KEMA have taken illustrated by model results and an initial rough view of how these may impact on the LRMC Parameters..

This report covers items 1. and 2.

3. Take inventory of feedback received from gencos and large consumers on draft recommendation and recommend final settings of technical LRMC parameters.

1.3 Starting points

A number of starting points were laid down in our initial meeting with EMA, gencos and large consumers. These are compiled in table 1.1.

Table 1.1 Starting points

Item	Category	Participant Feedback	KEMA response and starting points
1	**General**		
1.1		Analysis should include all costs during construction, commissioning and operation of the plant	Agreed
1.1		Capital costs, operating costs, et al should be discounted over the economic lifetime of the asset.	Agreed
1.2		All costs and parameters should include full lifecycle costs	Agreed – We have used full lifecycle costs in our modelling to derive the plant load factor.
1.3		Characteristics used in modelling should reflect those of the plant type chosen as the proxy plant	Agreed KEMA use this in all relevant aspects of the study

Table 1.1 Starting points (continued)

Item	Category	Participant Feedback	KEMA response and starting points
1.4		The chosen proxy should reflect incremental construction	Not agreed Although this would be appropriate for an incumbent, we believe a new player, to achieve full economies of scale, will likely construct more than one train. We are of the opinion that two 400MW_e (ISO) rated trains constructed side by side is appropriate (see section 3.1)
1.5		The chosen proxy plant should be consistent with the existing most reliable plant in operation in Singapore	Not agreed The definition of the proxy plant is the most efficient plant with existing technology already in use in Singapore that, together with existing plant of the same type, constitutes at least 25% of the supply capacity in the Singapore electricity market.
1.6		The chosen plant should reflect green field construction by a new industry player.	Agreed
2	**Plant capacity on site at 100% load**		
2.1		Temperature duration curves should reflect those at the power station location	Agreed KEMA will use localised temperatures at the Senoko, Seraya and TUAS power plants
2.2		Capacity to register with the EMC should represent the low point of capacity at the high point of the temperature duration curve	Not agreed KEMA view this as too pessimistic as the grid will accept availability declarations down to a ½ hourly granularity in the market. We have therefore taken the view that capacity is flexible up to the highest available at the coldest point of the temperature duration curve. KEMA will model the available capacity at the yearly average temperature

Table 1.1 Starting points (continued)

Item	Category	Participant Feedback	KEMA response and starting points
2.3		Heat curves to be included as part of the KEMA reports	Agreed KEMA will include heat curves where we have used them.
2.4		Participants requested KEMA to take account of aging in computation of the plant capacity	Agreed KEMA will included the effect of aging in our analysis and modelling to compute the plant factor.
3	**Plant Factor**		
3.1		Take account of reserve requirements and the co-optimisation of reserve, regulation and energy in the market model.	Not agreed KEMA have adopted the view that the model should compute the plant factor of the proxy plant based on fundamental analyses. This differs frrom modelling the market and the many strategies participants may adopt.. We believe a participant in the long run will offer to the market based on sound fundamental economics (best profit).
3.2		Modelling to validate that take or pay gas parameters are not breached	Noted Rolling take or pay agreements have a high degree of flexibility. Within the expected lifetime of an assumed contract for the proxy KEMA will confirm from the operating regime that it's take or pay obligations are met.
3.3		Modelling to take account of embedded generation	Agreed For generation of significant size KEMA will include embedded plant in our models that are effectively categorised as must run
3.4		Modelling to take account of plant in place and under construction.	Agreed KEMA have effectively assumed that the proxy plant is likely to come in after Keppel, being the closest actual development on the horizon being Island Power that could be considered as a reasonable proxy
3.5		Modelling to take account of load predicted over the economic lifetime of the plant	Agreed

Table 1.1 Starting points (continued)

Item	Category	Participant Feedback	KEMA response and starting points
3.6		Modelling to use assumptions consistent with the chosen plant type	Agreed
3.7		KEMA to calibrate model against historic operation	Agreed in part KEMA are concerned that historic operation does not reflect the same situation as a new IPP there being none in place at the moment. We will, however publish the dispatch schedules from the model.
3.8		Participants Requested KEMA to use actual data from similar plant to the proxy that is already in place	Not agreed See the comment to 3.7 above.
4	**Yearly Average Heat Rate**		
		No Comments	
5	**Investment Cost**		
5.1		Participants requested interest during construction to be taken into account in investment cost	Not agreed This should be included in a correctly executed discounted cash flow analysis that is outside the scope of our exercise KEMA will exclude it to avoid double accounting
5.2		Local cost in Singapore to be adequately reflected	Agreed
5.3		Reference costs should be consistent with proxy plant	Agreed
5.4		Include cost of land development/preparation	Agreed
5.5		Include costs of transformers (generator pays for this in Singapore).	Agreed Will be included in the infrastructure cost
5.6		Include costs of switchyard	Agreed c.f. 5.5 above
5.7		Include start-up costs (staff take on etc in advance of commercial operation starting)	Agreed KEMA will factor this in as appropriate

Table 1.1 Starting points (continued)

Item	Category	Participant Feedback	KEMA response and starting points
5.8		Consider long term view of commodities in relation to equipment prices (e.g. steel costs)	Noted: We will take a reasoned view of costs when constructing our capital cost model
6	Build Duration		
6.1		It is generally agreed that a build duration of 2 to 2.5 years is reasonable. This should consider time from financial close to full commercial operation	KEMA have assumed a 2¼ year build duration
7	Fixed Annual Running Cost	Costs to Include the list below	
7.1		Cost of trading in the market	Agreed
7.2		Cost of Backup Fuel (90 Days ultra low sulphur diesel – minimum 60 days on site)	Agreed
7.3		Cost of fuel to be considered over economic lifecycle of the proxy plant.	Agreed
7.4		Hot switching capability costs (Primary to backup fuel)	Agreed
7.5		The cost of business interruption insurance	Agreed KEMA will make assumptions on the level of cover and when it will kick in following an interruption in forming a reasonable view of this cost.
7.6		Maintenance Costs (Fixed or variable consideration is fine)	Agreed
7.7		Probability of increased maintenance costs resulting from poor operation (e.g. two shifting)	Noted We will look at this only if the model suggests there will be problems in this area over the plant effective lifecycle
7.8		The cost of spares holding	Noted This is part of the LTSA with the manufacturer (section 6.1.3)
8	Variable running costs non fuel	Participants wish the following list of items to be included	
8.1		Transmission Grid Charges	Agreed
8.2		EMC Fees	Agreed
8.3		PSO Fees	Agreed

Table 1.1 Starting points (continued)

Item	Category	Participant Feedback	KEMA response and starting points
8.4		Gas Network Transportation Charges	These charges are still under discussion and as yet not finalised. EMA has instead furbished us with an average gas price that has been computed taking accordance of transportation costs
8.5		GSO Fees	Noted: c.f.8.4 above
9	Economic Lifetime		
9.1		It was recommended that an economic lifetime of 20 years be considered in the study	Agreed
9.2		It was recommended the residual value should be taken as greater than zero at the end of the 20 years	Not Agreed KEMA believe it normal to reduce residual to 0 over the economic lifecycle of the plan. This is consistent with LRMC parameter computations made in the past

2 TECHNOLOGY

The most efficient technology that currently serves at least 25% of Singapore's electricity demand is the so-called F-technology. Table 2.1 gives some more information about the F-technology (b).

Table 2.1 50 Hz representatives of the F technology and some data (b)

Manufacturer	Alstom	General Electric	Mitsubishi	Siemens
Type designation CCGT	KA26-1	S109FA	MPC1 (M701F)	1S.V94.3A
Type designation GT	GT26	MS9001FA	M701F	V94.3A
Net capacity (MW, ISO, new)	410	391	398	398
Net efficiency (on LHV, ISO, new)	57,8%	56,7%	57,0%	57,5%
Type steam cycle	3-pressure, reheat	3-pressure, reheat	3-pressure, reheat	3-pressure, reheat

ISO conditions: 15 °C ambient temperature, 1,013 bar ambient pressure

3 PLANT CAPACITY ON SITE @ 100% LOAD

3.1 ISO capacity new

The typical single train capacity at ISO conditions, in new-state for the F-technology is app. 400 MW_e (see table 2.2). A typical green field plant constructed by a new industry player would in KEMA's view be 800 MW_e, realized in two single trains of 400 MW_e (ISO). A single train with two gas turbines and one steam turbine could also be realized. This would lead to a reduction in investment cost, but would lead to less favourable operational flexibility with respect to low load and start-stop operation. In practice often the 2*400 option is chosen (KEMA (c, d)). In the Singapore market a single 800 MW_e train would also attract significant cost of reserve power in the market.

3.2 Impact of ambient conditions

3.2.1 Air temperature

Due to higher ambient temperatures, plant site capacity will be lower than the ISO capacity. The gas turbines that drive the combined cycles are essentially constant volume machines. They suck in a volume flow of air that is indifferent to ambient conditions. As the ambient temperature increases, its density decreases. At constant volume flow the mass flow of air sucked in decreases. To keep operating conditions within the envelope the amount of gas fired has to decrease proportionally. Ergo the capacity of the combined cycle decreases. Figure 3.1 shows the relation for a combined cycle based on the 9FA gas turbine (GEC Alstom (e)). Inspection of the temperature data provided by EMA[1] indicated an average temperature at the Seraya, Senoko and Tuas sites of 29½ °C, with a minimum (2*standard deviation) of 26°C. The average air temperature of 29½ °C results in a reduction of 7% with respect to the ISO capacity.

[1] EMA, Pwee Inn Loy. E-mail May 5th, 2006

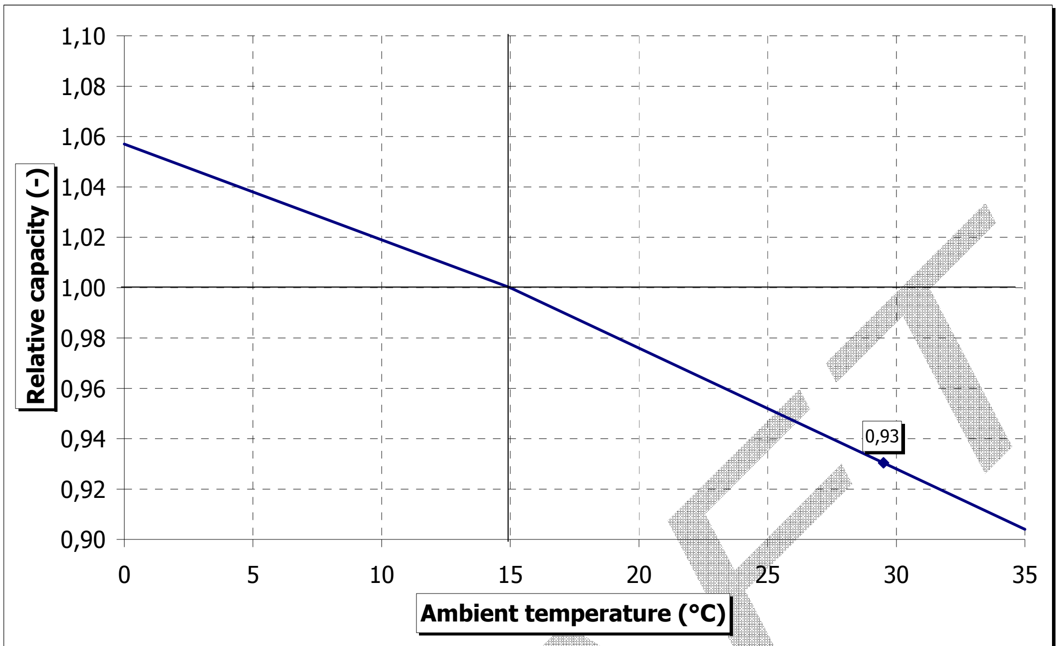

Figure 3.1 Impact of ambient temperature on F class CCGT capacity (GEC Alstom (e))

3.2.2 **Air pressure**

Ambient pressure does not feature, because Singapore is at sea level.

3.2.3 **Cooling water temperature**

There is a significant impact of the cooling water temperature on the capacity of the combined cycle (figure 3.2). Cooling water temperature is taken at 28 °C. At this temperature there is a reduction of app. 2%.

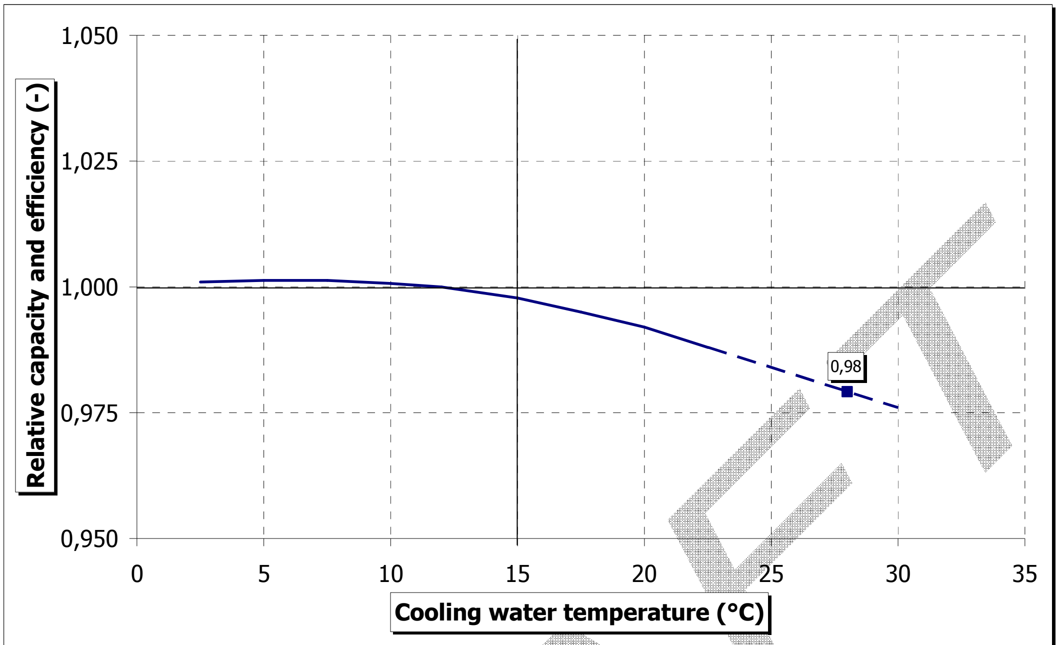

Figure 3.2 Impact of cooling water temperature on capacity and efficiency of combined cycle (GEC Alstom (e))

3.3 Plant capacity on site @ 100% load in new state

Based on the arguments above we calculate the average net plant capacity on site @ full load in new state to be 0,93 (ambient temperature) * 0,98 (cooling water temperature) is **729 MW$_e$**. This is a reduction of 9% compared to the ISO rating of 800 MW$_e$.

3.4 Impact of ageing

The performance of combined cycle power plants is subject to ageing, predominantly in the gas turbine. Figure 3.3 shows the expected relation by Alstom (g). We observe that over a period of 15 – 20 years (120 000 operating hours), the capacity will have decrease by approximately 3%. We take account of this within the 20 year model that we use to validate the plant factor.

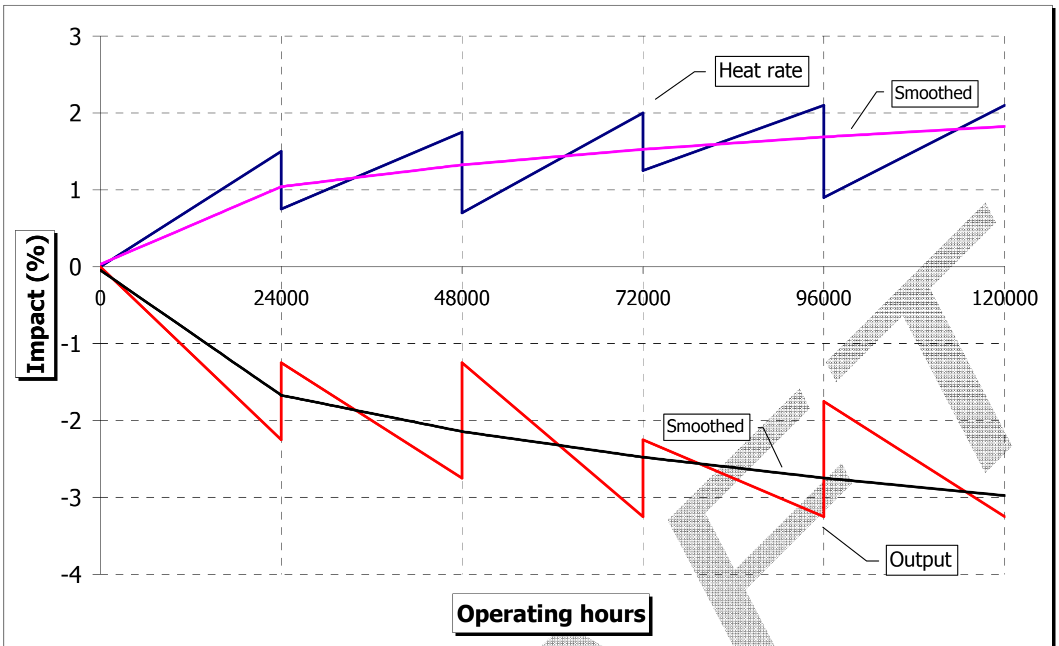

Figure 3.3 Impact of ageing on GTCC heat rate and capacity (Alstom (g)).
Discontinuities indicate revisions and overhauls

4 HEAT RATE

The yearly average heat rate depends on the following parameters:

- ISO efficiency @ 100% load
- Ambient conditions
  - Air temperature
  - Air pressure
  - Cooling water temperature
- Ageing
- Load profile
  - Part-load
  - No of starts
  - Regulation

4.1 ISO efficiency at 100% load

The typical efficiency under ISO conditions in new-state at MCR is 57¼ % on lower heating value (table 2.2). This corresponds to a heat rate of 5960 Btu/kWh

4.2 Impact of ambient conditions

4.2.1 Air temperature

The efficiency of a combined cycle is relatively independent of the ambient temperature. For temperatures above 15 °C the impact is virtually negligible (figure 4.1) at 0,999 at 29½ °C .

4.2.2 Air pressure

Ambient pressure does not feature, because Singapore is at sea level.

4.2.3 Cooling water temperature

There is a significant impact of the cooling water temperature on the efficiency of the combined cycle (figure 4.2). At a cooling water temperature of 28 °C (section 3.2.3), there is a decrease of efficiency of app. 2%. This corresponds to an increase of 2% in heat rate.

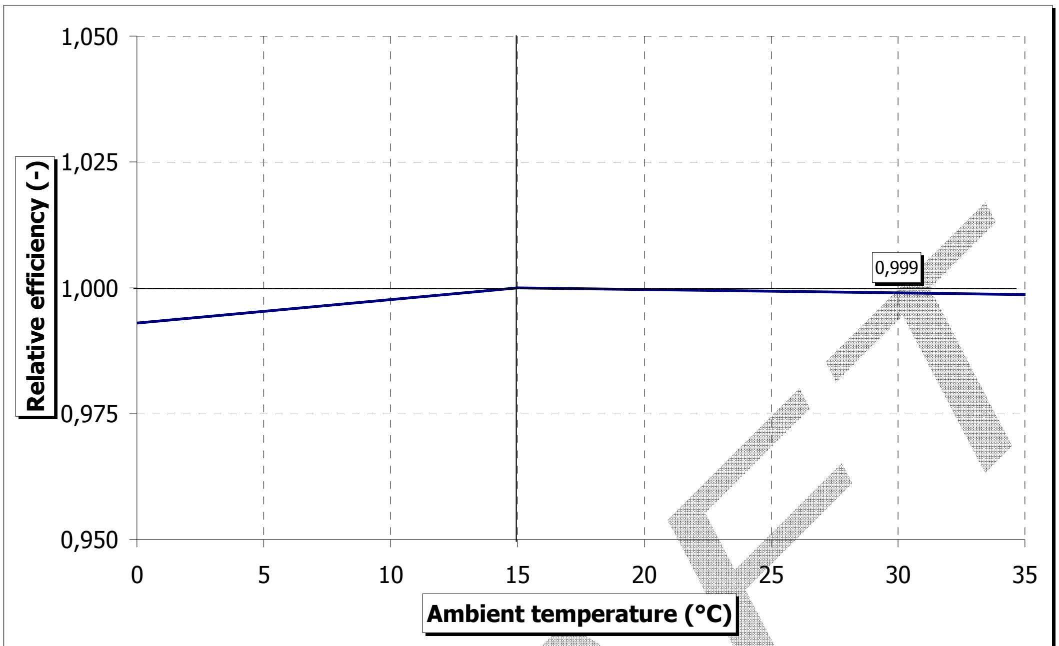

Figure 4.1 Impact of ambient temperature on F class CCGT efficiency (GEC Alstom (e))

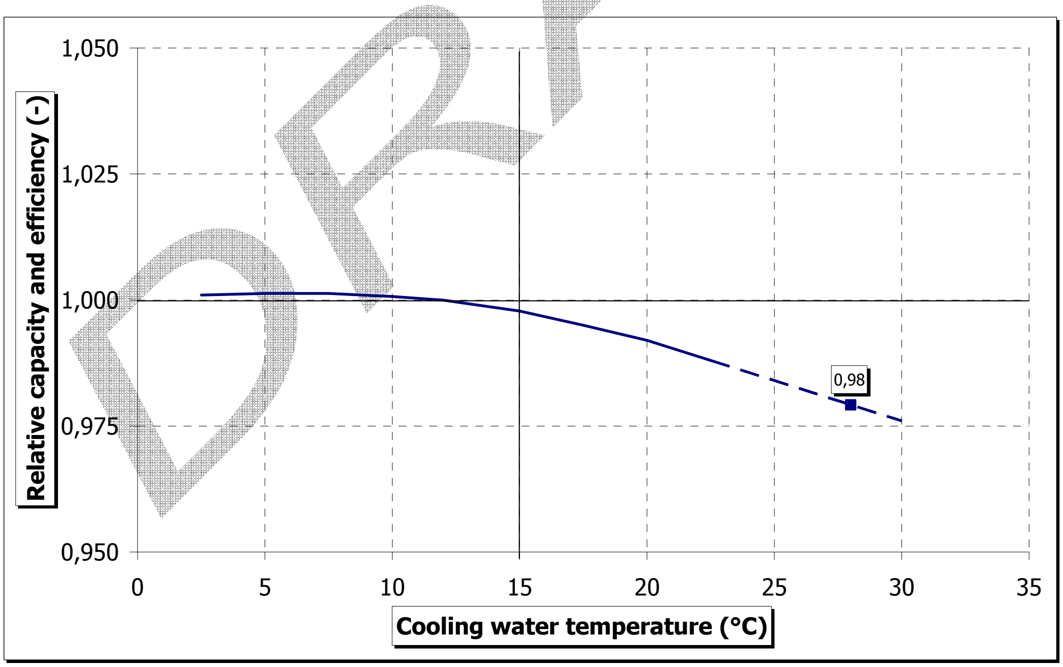

Figure 4.2 Impact of cooling water temperature on efficiency of combined cycle (GEC Alstom (e))

4.3 Average plant heat rate on site @ 100% load in new state

Based on the arguments above we calculate the average net plant heat rate on site @ full load to be 5960 / 0,999 (ambient temperature) / 0,98 (cooling water temperature) is 6088 Btu/kWh on lower heating value. This corresponds to 56,05 % efficiency. Taking into account a ratio HHV/LHV of the gas of 1,108 the avarage plant heat rate on site based on HHV is 6088 * 1,108 is 6746 Btu/kWh.

4.4 Impact of ageing

The performance of combined cycle power plants is subject to ageing, predominantly in the gas turbine. Figure 4.3 shows the expected relation by Alstom (g). We observe that over a period of 15 – 20 years (120 000 operating hours), the heat rate will have increased by approximately 2%. The average increase in heat rate during this period will be app. 1¼ %.

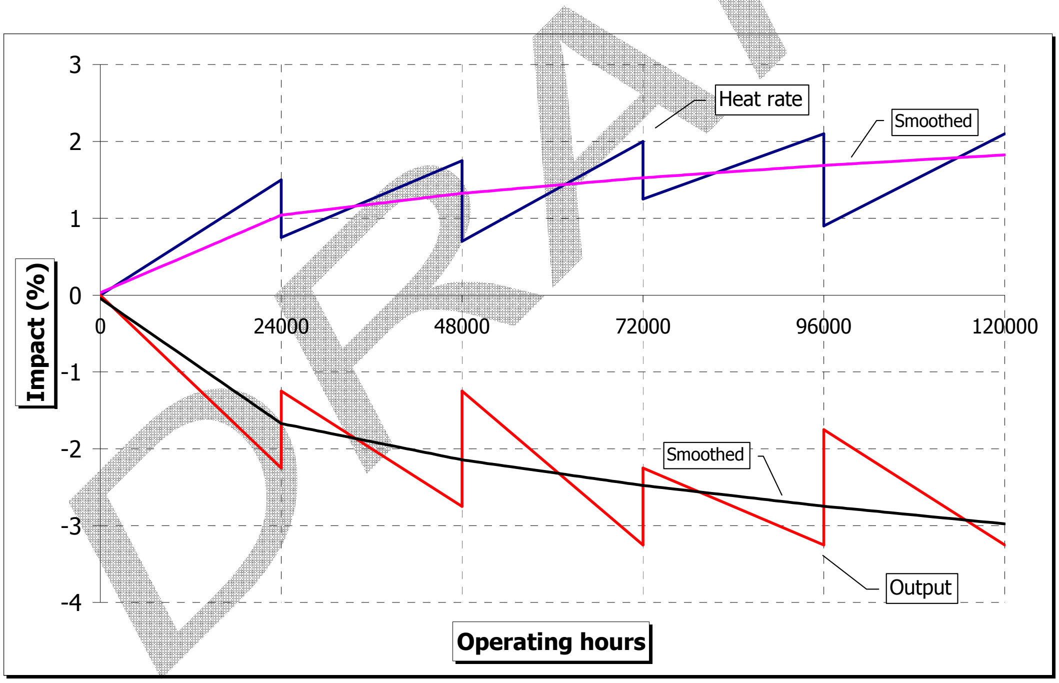

Figure 4.3 Impact of ageing on GTCC heat rate and capacity (Alstom (g)). Discontinuities indicate revisions and overhauls

4.5 Load profile

4.5.1 Impact of part load

Figure 4.4 shows the impact of part load on an F class GTCC. We see e.g. that at 51 % load the efficiency decreases to 92,6% of the value at 100% load. The heat rate increases by 8%.

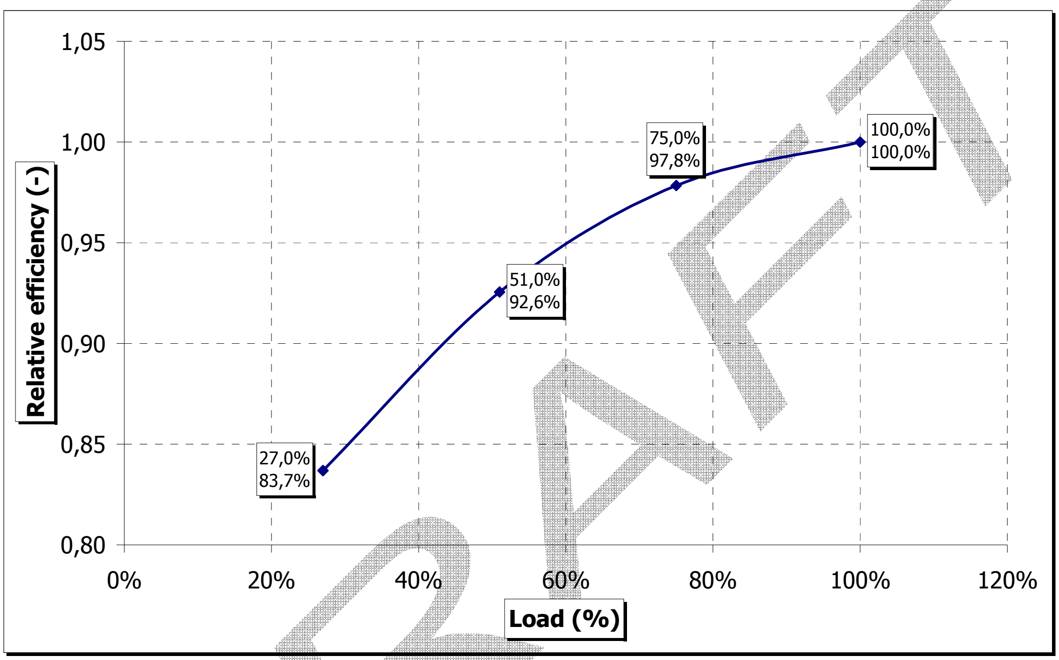

Figure 4.4 Impact of part load on F class CCGT efficiency (GEC Alstom (e))

4.5.2 Impact of number of starts

The additional fuel consumption of a start[2] is conveniently expressed as the number of operating hours at full load that has equal fuel consumption (h). For a hot start (after a night shutdown) this is ½ operating hour and for a warm one this amounts to 1 operating hour. Expressed in fuel consumption these numbers are 700 and 1400 MWh respectively. This number will be used in the estimation of the plant factor as additonal cost for a start.

---

[2] The fuel consumption that does not lead to electricity consumption

4.5.3 **Impact of regulation**

According to Tuas (i) *Generation schedules (supply) will not match load (demand) instantaneously. Automatic Generation Control (AGC) systems provide "regulation" to keep generation (with small generation output) and load in balance in real-time*.
This regulation will increase fuel consumption due to non-steady state operation. We estimate this will increase the heat rate with app. ½ % (j).

4.5.4 **Yearly average heat rate**

The ultimate yearly average heat rate is determined together with the load factor by taking into account above impacts in the simulation of the dispatch of the proxy power plant in the market (section 8)

5 INVESTMENT COST

This section describes the estimation of the investment cost for natural gas-fired CCGT operating in Singapore: the so-called proxy plant. The derivation is outlined in table 5.1. The italic numbers in brackets in the text below refer to the corresponding rows in the table.

5.1 Plant capacity

The net electric capacity at ISO conditions in new-state is 800 MW, divided over two trains of 400 MW each (*1*). The average site capacity was determined at 715 MW_e in section 3.3 (2). The maximum capacity on site is reached in new-state when the air and cooling water temperature are at its lowest. From section 3.2 these temperature are 26 and 24½ °C respectively. From figure 3.1 and 3.2 we calculate a maximum site capacity of 746 MW_e (*3*). This capacity determines the connection charge (*21 – 23*).

5.2 EPC power island

KEMA estimates the equipment cost (FOB) for the combined cycle at 275 EUR/$kW_{e,ISO}$ for a single gasuous fuel plant (4). For dual fuel hot switching capability an estimated cost of 5 MEUR per GT is added (5). At 800 $MW_{e,ISO}$ this corresponds to 230 MEUR or 478 MSGD[3]. For the transport cost (6) we estimate 2% of the equipment cost (4, *5*). For the construction of the power island we estimate a cost of 63 MEUR, being 70% of the West-European value (7)[4]. Provision of spare parts *(8)* is part of the LTSA[5] with the manufacturer.
This yields an EPC cost for the power island of 619 MSGD | 298 MEUR (*8*), corresponding to specific cost on ISO basis, in new-state of 774 SGD/kW_e | 372 EUR/kW_e.

[3] using an exchange rate of 2,08 SGD/EUR, the average over 2005.
[4] Construction cost appears to be significantly lower in South-East Asia than in West-Europe. Causes may be: lower wages, lower cost of supervision, less power of trade unions (k)
[5] Long Term Service Agreement

5.3 Land cost

For land lease JTC (l) quote an upfront premium of 1 240 000 SGD per ha for a period of 30 years in the Jurong area (*10*). Water front fee is quoted at 360 – 540 SGD/meter per year. We take the centre value of 450. This is the same as in the previous vesting period. We convert into an upfront premium for 30 year, using a discount rate of 6% real. This results in an upfront premium of 6 200 SGD per meter (*11*). We have added land preparation cost (m) at 100 000 EUR/ha (*12*). Apparently this item was not included in the previous vesting period (m1). Thus the total land cost amount to 19,34 MSGD (13).

5.4 Facility cost

KEMA estimate a cost of 37,5 MSGD for the facility cost, comprising of, ancillary buildings, awitch-house, seawater intake/outfall, jetty for emergency fuel unloading and gas receiving facilities (*14 – 19*).

5.5 Emergency fuel facilities

A generation licencee is required to emergency fuel facilities for 60 days on site. This amounts to 87 500 b (section 6.1.2) or 175 million liters. KEMA estimate the cost for tankage and auxiliaries for this storage at 27,3 MSGD (20).

5.6 Connection charge

The standard connection charge (n) of 50 000 SGD of the previous vesting period is still valid (*21*). KEMA estimate a specific cost of 25 000 SGD/MWe for the cost of 230 kV switch gear (including transformers, switch yard and underground cable). At a total capacity of 746 MWe this amounts to 18,65 MSGD. Thus the total connection charge amounts to 55,95 MSGD.

5.7 Installation cost

The Installation cost (*24*) has been moved to Power island construction (*6*). KEMA's estimate of these cost of 131 MSGD is clearly higher than the estimate in the previous vesting period (52 MSGD).

Consultancy cost

KEMA estimate a consultancy cost of 11 MSGD for engineering studies, legal and financial advice *(25 – 28)* .

5.8 Total land, infrastructure and development cost

The considerations above lead to total land, infrastructure and development cost of 151 MSGD | 73 MEUR *(29)*.

Table 5.1 Derivation of investment cost for <u>two</u> 400 MW_e ISO trains built side by side

		Parameter	Specific price	Total cost kSGD	kEUR
1	Unit ISO capacity	400 x 2			
2	Unit average site capacity	357,5 x 2			
3	Unit max site Capacity	373,0 x 2			
	Power island				
4	Equipment		275 EUR/$kW_{e,ISO}$	457 600	220 000
5	Hot switching capability		5 000 kEUR/GT	20 800	10 000
6	Transport cost	2% of 4, 4a		9 568	4 600
7	Construction			131 040	63 000
8	Spare parts			-	-
9	**EPC Power island**			**619 008**	**297 600**
	Land, infrastructure & development cost				
	Land cost				
10	Land lease	12,5 ha	1 240 000 SGD/ha	15 500	7 452
11	Water front fee	200 m	6 200 SGD/m	1 240	596
12	Land preparation	12,5 ha	100 000 EUR/ha	2 600	1 250
13	**Total Land cost**			**19 340**	**9 298**
	Facility cost				
14	Ancillary buildings				
15	Switch-house				
16	Seawater intake/outfall				
17	Jetty emergency fuel unloading				
18	Gas receiving facilities				
19	**Total Facility cost**			**37 500**	**18 029**
20	**Emergency fuel facilities 2006**	175 000 m^3	75 EUR/m^3	**27 300**	**13 125**
	Connection Charge				
21	Standard connection charge	746 MW	50 000 SGD/MW_e	37 300	17 933
22	Cost of 230 kV switch gear (including transformers, switch yard and underground cable)	746 MW	25 000 SGD/MW_e	18 650	8 966
23	**Total Connection Charge**			**55 950**	**26 899**
24	**Installation Cost**	*Moved to construction (5)*			
	Consultancy Cost				
25	Engineering Studies				
26	Legal Advice				
27	Financial Advice				
28	**Total Consultancy Cost**			**11 000**	**5 288**
29	**Total Land, infrastructure & development cost**			**151 090**	**72 639**
30	***Total investment cost***			***770 098***	***370 239***
31	***Ditto specific (SGD/kW_e, EUR/kW_e)***	***Site average***		***1 077***	***518***
32	***Ditto specific (SGD/kW_e, EUR/kW_e)***	***ISO, new***		***963***	***463***
33	Exchange rate (SGD/EUR)	2,08			

6 RUNNING COST

We distinguish between fixed running cost and variable non-fuel cost.

6.1 Fixed running cost

6.1.1 Manpower, overhead, etc

KEMA estimate the cost for manpower, corporate overheads, working capital and other expenses (insurance, property tax, etc) at 16 MSGD/a[6].

6.1.2 Carrying backup fuel

For the cost of carrying backup fuel we estimate a cost of app. 14 MSGD/a. The derivation is as follows:

Average site capacity (MWe)	715
Average site efficiency	55%
Daily fuel consumption (MWh)	31 200
90 Days fuel consumtion (MWh)	2 808 000
LHV diesel oil (MWh/b)	1,70
Barrels needed for 90 days	1 651 765
Diesel (50 ppm) price USD/b	84
Stock value (USD)	138 748 235
Carrying cost @ 6% real discount rate (USD/a)	8 324 894
Ditto SGD/a	14 000 000

6.1.3 Maintenance

For maintenance of the power plant main components we estimate a cost of 225 MEUR, including spare parts (o) in West-Europe, based on an LTSA with the manufacturer for 100 000 EOH or a duration of 12 years (whichever comes first). This is 18,75 MEUR/a or 2 250 EUR/EOH. For Singapore we assume a mark-down of 10%[7], resulting in 16,88 MEUR/a or 2 025 EUR/EOH**.** This corresponds to 35 MSGD/a or 4200 SGD/EOH. For the routine maintenance of the plant we estimate an additional 5 MSGD/a.

---

[6] 3,11 + 4,89

[7] materials no mark-down; labor & supervision 30% mark-down

6.2 Variable non-fuel cost

6.2.1 EMC fees

EMC, the Energy market company, is the market operator under the New Electricity Market rules. Generators pay an administrative fee to this company, based on the number of MWh injected to the grid. For the fiscal year April 2006 – March 2007 this fee is indicated at 0,38 SGD/MWh (p).

6.2.2 PSO fees

The Market Rules require EMC to publish the Power System Operator's schedule of fees for a given fiscal year. The PSO's budget for the period 01 April 2006 to 31 March 2007 is SDG 15 043 million. PSO's administrative fee for the wholesale electricity market for this period is 0,208 SGD/MWh[8].

6.2.3 Consumables

KEMA estimate the cost of consumables (water, oil, chemicals) at 0,2 SGD/MWh electricity produced.

[8] http://www.emcsg.com; Budgets and Fees; PSO budget & fees (FY2006/07)

7 OPERATIONAL CHARACTERISTICS

This section sets the parameters for the operational characteristics of the proxy plant. These additional parameters will be used in the simulation to estimate the plant factor (see section 8).

7.1 Availability

KEMA expect an availability of at least 90% based on the work of Alstom Power (g).

7.2 Practical minimum load

KEMA expect a practical minimum load of app. 55% based on allowable NO_x-emissions. Below this load the emissions increase strongly (see e.g. ref (q, r)).

7.3 Ramp-up speed

KEMA expect an achievable ramp rate (from practical minimum load to full load) of app. 3% or 24 MW per minute (see e.g. ref. (q, r)).

7.4 Start-up time

Start-up time for to full load for a hot start (after a night outage) is expected to be app. 1½ hours. For a warm start (after a weekend outage) we expect 2½ hours to full load. For a completely cold start we expect 6 hours (see e.g. ref (o)).

7.5 Cost of a start

A start has two effects, that is:
1. Additional fuel consumption
2. Additional wear of the installation

The additional fuel consumption is conveniently expressed in a consumption corresponding to a number of operating hours at full load. For a hot start (after a night shutdown) this is ½ operating hour and for a warm start this is 1 operating hour (h). Expressed in fuel consumption this is 700 respectively 1 400 MWh.
For the additional wear we reckon in equivalent operating hours as well. For a combined cycle one start corresponds to approximately 10 operating hours. Expressed in cost this is about 42 000 SGD/start (see also previous section).

8 PLANT FACTOR AND YEARLY AVERAGE HEAT RATE

8.1 Introduction

The plant factor is defined as:

Actual GWh delivered to grid in one year / *Theoretical maximum*

The theoretical maximum is determined by running full load for the whole year (8766 hours, including leap years). So for a plant with an average site capacity of 715 MW_e, the theoretical maximum is 715 * 8766 / 1000 is 6268 GWh.

The plant factor is a result of the dispatch of the plant. The optimum dispatch depends on:

- Marginal cost of the plant
- Marginal cost of the other plants in the market
- Operational characteristics of the plant
- Operational characteristics of the other plants in the market
- System load
- System constraints like network constraints and requirements for ancillary services

The contributors to the marginal cost of the proxy plant are:

- Fuel price
- Heat rate (section 4)
- Variable non-fuel cost (section 6.2)

Operational characteristics of the plant that impact on the dispatch are (section 7):

- Availability
- Practical maximujm and minimum load
- Ramp-up speed
- Start-up time
- Cost of a start

8.2 Estimation of the plant factor

In the Singapore market the dispatch is done by the PSO, the Power System Operator. The PSO uses the Market Clearing Engine (MCE) to determine the least-cost dispatch schedule and market prices. KEMA uses a similar software tool called Prosym to simulate the optimum dispatch of the Singapore generating units. Prosym takes into account all the influences mentioned in the previous section. The plant factor of the proxy CCGT is determined by simulation of the Singapore wholesale market for a period of 20 years (the economic lifetime of the proxy plant). For this simulation the information described in the previous section is required to feed the model. In Appendix It he relevant numbers are recorded. Apart from these data the development of the system in the coming 20 years is important. The supply and demand balance will change due to a growing demand and changes in the composition of the supply. This will influence the plant factor of the CCGT. Old plants will probably be taken out of operation and new plants will be commissioned. A plan has been made for this development based on the expected load development, the commissioning dates and technology of the new units and assumptions on the life time of the units.

8.2.1 **Assumptions concerning market development**

Below the main assumptions concerning the market development are compiled

- Load development (MW, GWh) according to *Elec Forecast (EMA March 2006 Review.xls)*
- Load pattern is based on 2005 half hourly load data (EMA web site)
- Initial expansion plan is based on an Reserve Margin falling below 30% in any year
- For initial simulations existing units are decommissioned after 25 years (CCGTs) and 35 years (Steam units)
- Decommissioned units are replaced by CCGT units with better performance than the proxy CCGT due to the expected better technology available by the time new capacity is required
- The must-run units are assumed to live until the end of the evaluation period or be replaced between times by similar units with the same generating capacity
- Spinning reserve requirement is 1,5 times largest dispatched capacity
- CHP units (Sembcorp, Exxon, Syngas and Merlimau) are considered must-run units. This implies that these units will run at maximum capacity when they are available
- The *Environment* plant is also considered must-run
- The plant characteristics are according to the KEMA data base and actual site conditions (Appendix I)
- Characteristics of the Proxy plant are according to this report
- Fuel prices for the whole period are based on a crude oil price of 60 USD/b (ORBP). Sensitivity calculations are performed for 40 and 80 USD/b
- HSFO price is 80% of ORBP
- Orimulsion price is 60% of ORBP

- Gas prices are according to EMA calculations
- Initial efficiency of future CCGTs is adjusted for improved technology
- Efficiency and capacity derating due to ageing of running CCGTs is accounted for
- Variable operation and maintenance costs are not considered in the commitment and dispatch of the units
- Co-optimisation is not taken into account, as the simulations are performed to determine the merit order in a competitive market without strategic behaviour of market participants. We assume that the owner of the proxy plant will bid low enough to ensure dispatch of the plant during all available hours. Owners of all other plants are assumed to do the same.

To illustrate the interaction between the demand and the supply figure 8.1 shows the supply curve and the Load duration curve (LDC) of 2007.

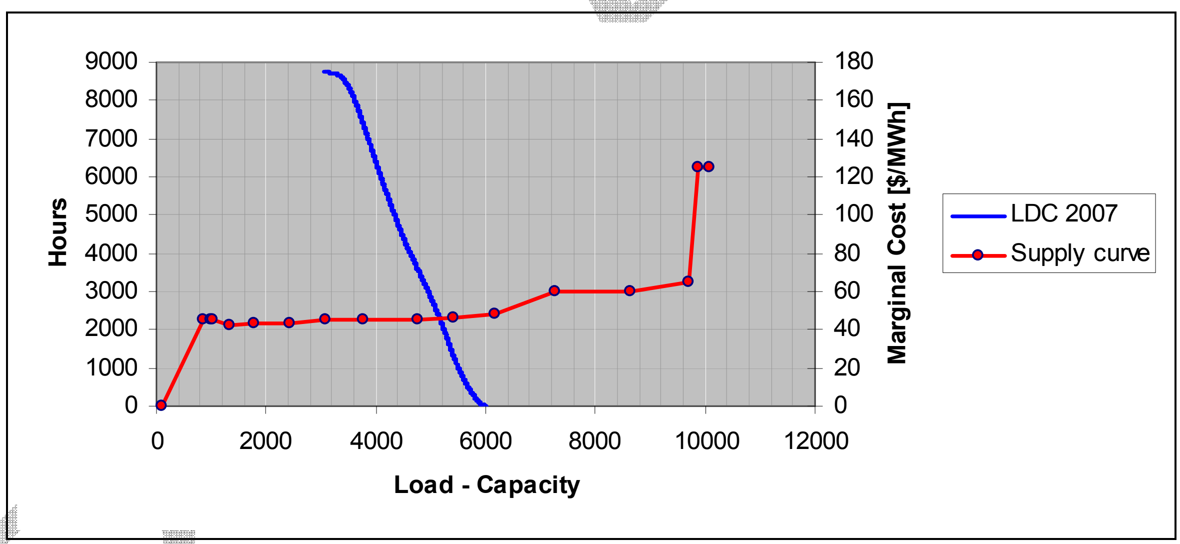

Figure 8.1 Supply and load duration curves of 2007

We observe the following. The load is always more than 3500 MW. Of this 3500 MW about 1200 MW (present view) is served by must run capacity. Also there is 750 MW of Orimulsion capacity in the system which is cheaper than the CCGTs. This makes about 2000 MW of capacity placed in the merit order and running before the CCGT capacity. A new CCGT unit would come right on top of this 2000 MW and would therefore be pure base load capacity. In the course of time new units would come in and would push the proxy CCGT down in the merit order at the same time the LDC would shift to the right, due to increasing demand. How this impacts on the plant factor in the course of time is shown in the next section.

Initial results

The initial results are the actual output from the model fed with the data presented before.

The expansion plan with the forecasted load, the new generating capacity, the total capacity and the reserve factor is shown in figure 8.2.

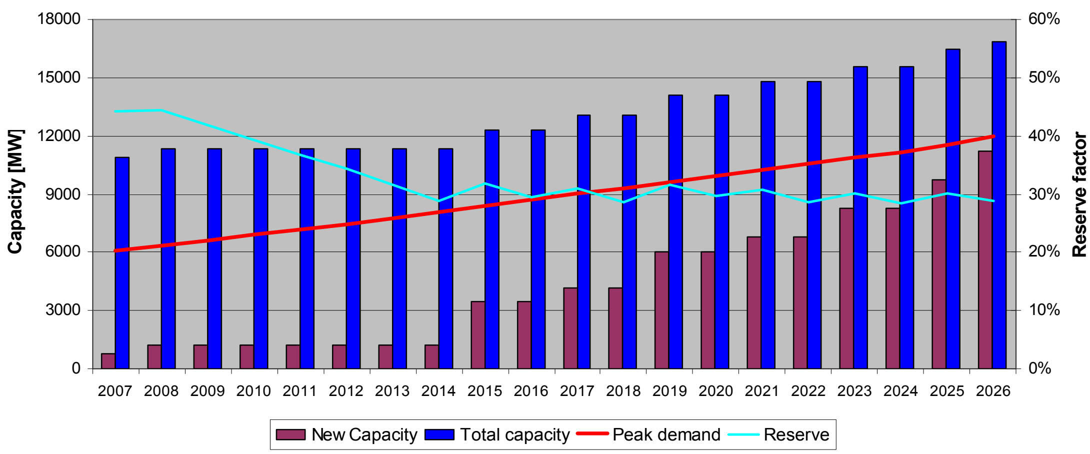

Figure 8.2 Expansion plan based on used assumptions

We observe the following. For a reliable supply (Reserve not falling below 30%) no additional capacity, apart from the proxy CCGT and the Merlimau plant (under construction) would be required before 2015. The reserve factor would decrease from over 40% to about 25%. After 2015 new additions would be required every 2 years to maintain the desired reliability.

The break down of generating capacity and load is indicated in figure 8.3. The capacity for each type of plant (CCGT, OCGT, Steam, must-run) is shown together with the maximum and minimum forecasted load.

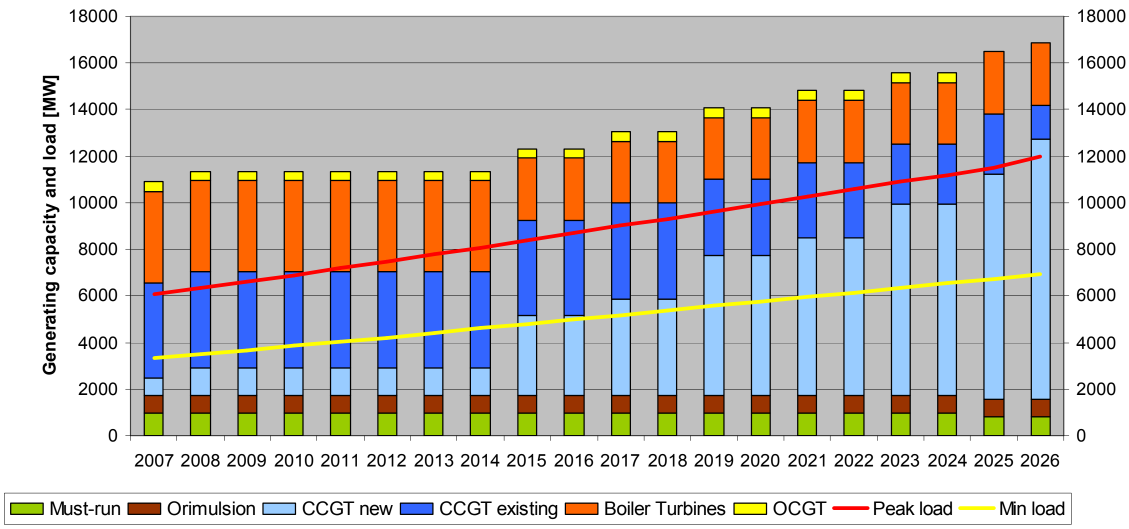

Figure 8.3 Capacity per type of plant according to expansion plan

The red line shows the peak load according to EMA and the yellow one is the minimum load development. Assumed is that all required capacity expansion is by means of new CCGT units. Each unit will be slightly more efficient than the last one added. The proxy CCGT would be between the light and dark blue bars. Everything below the yellow line will run in absolute base load. This means that the proxy plant will in base load during twelve years up to and including 2018. From then on it will be more and more a mid merit unit.

8.2.1.1 Plant factor

One of the results of the initial simulations is the annual plant factor for the proxy CCGT for each year from 2007 up to and including 2026, that is tabulated below (table 8.1) and calculated relative to the site capacity of the proxy CCGT in new state (729 MW_e). We observe a plant factor of about 88% for the first ten years. After 2016 the plant factor decreases due to increasing new (more efficient) capacity being added to the system and reduction of the capacity through ageing. The arithmetic average over 20 years is **78%**.

We emphasize these results are initial results and need to be discussed with EMA, the gencos and large consumers.

Table 8.1 Plant factor of proxy CCGT relative to site capacity in new state (729 MW_e)

Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Plant factor	89,4%	88,3%	88,0%	88,3%	88,1%	88,1%	87,7%	87,7%	87,1%	87,2%
Year	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Plant factor	86,4%	86,9%	79,7%	81,9%	76,3%	79,2%	56,6%	62,2%	41,9%	24,5%

8.2.1.2 Yearly average heat rate

The other result is the yearly average heat rate, taking into account
- Average plant heat rate on site @ 100% load in new state
- Impact of ageing
- Impact of part load
- Impact of number of starts
- Impact of regulation

The results are indicated in table 8.2. We observe a gradual increase in heat rate due to aging and operation away from base load. The arithmetic average over 20 years is **6902 Btu/kWh** on HHV. We emphasize these results are initial ones and need to be discussed with EMA, the gencos and large consumers.

Table 8.2 Yearly average heat rate

Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Yearly average heat rate (Btu/kWh)	6 781	6 812	6 842	6 858	6 860	6 864	6 866	6 870	6 876	6 877
Year	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Yearly average heat rate (Btu/kWh)	6 885	6 885	6 926	6 924	6 946	6 938	6 979	6 969	7 007	7 084

REFERENCES

(a) EMA, 2005. TERMS OF REFERENCE. Consultancy Services to Review the Technical Parameters for LRMC (Long Run Marginal Cost) of CCGT (Combined Cycle Gas Turbine) for Setting the Vesting Price for the Period 1 January 2007 to 31 December 2008

(b) GAS TURBINE WORLD, 2004-5 GTW Handbook

(c) KEMA, 2005, Environmental impact report. ENECOGEN power plant of 840 MW_e in Europoort (Rotterdam). Report no; 50562004 KPS/PIR 05-3623 (in Dutch)

(d) KEMA, 2004, Environmental impact report. Sloe power plant. Report no: 50251450 KPS/TPE 03-1049 (in Dutch)

(e) KEMA, 1995, (Schaafsma, C.T.). Proposal for the guarantee and performance measurements of the combined cycle power plants EC 3-7 of the Eemscentrale. Report no: 33963-FPP 95-6814 Revision 1. *Includes GEC Alstom correction curves*.

(g) ALSTOM Power, 2003, (Fetescu, M.). Gas Turbine Technology and Cycle Selection for Combined Cycle Power Plants. Presented at: ASME Turbo Expo 2003, Atlanta.

(h) KEMA, 2006, (Koetzier, H., Braam, A.L.H.). Purchasing A Power Plant: The Role Of Technical Due Diligence. Presented at: Power-Gem Middle East, Abu Dhabi.

(i) TUAS POWER SUPPLY. An Introduction to NEM Market Rules, Tuas Power Supply Pte Ltd, sheet 20

(j) KEMA, 2006, (Dusomos, G.T.J.). Vocal communication

(k) ALSTOM POWER TURBO-SYSTEMS, 2006, (Bopp, C., Ladwig, M.). Meeting with KEMA representatives, April 11, 2006.

(l) JTC, 2006. JTC's land rent and Prices, with effect from 1 January 2006 (Jurong, Tuas view)

(m) KEMA, 2005, (Braam, A.L.H.). Utility Fixed Assets Valuation Study for Barbados Light & Power Company Limited (m1) EMA, 2004, Long Run Marginal Cost (LRMC). Parameters for 1 January 2005 to 31 December 2006. September 2004.

(n) SP POWER GRID, Transmission Rate Service Schedule, downloaded April 19, 2006

(o) SIEMENS POWER GENERATION, 2005, (Anonymous). Proposal for CONFIDENTIAL

(p) EMC, 2005, (Tan, Z.Y.) Budget for FY 2006/2007. December 22, 2005.

(q) KEMA, 2005, (Braam, A.L.H. et al). Project Springfield Technical Due Diligence

(r) KEMA, 2000 – 2006, (Koetzier, H.). Charge! – KEMA generation database.

APPENDIX I ASSUMPTIONS FOR PLANT FACTOR ESTIMATE

General assumptions on generating units

	Lifetime	Start-uptime (hours)	Planned maintenance	Forced Outage	Minimum load
Steam units	35	4	5.0%	5.0%	30%
CCGTs	25	2	5.0%	5.0%	55%
OCGT	25	1	5.0%	3.0%	60%

Fuel pricing

Fuel prices are based on an OPEC Reference Basket Price (ORBP) for crude oil of 60 USD/b. Prices of other crude oil related fuels can be derived from the crude oil price using historically determined ratios. The price for natural gas has been provided by EMA based on the crude oil price. All used ratios and prices are shown below. The exchange rate is 1,7 SGD/USD.

	ORBP	Ratio to ORBP	Fuel price
	USD/b		SGD/GJ
HSFO	60	0,80	13.3
LFO	60	1,25	20.8
Orimulsion	60	0,40	6.7
Natural gas	60		13,7