Thermal Power Station Advice

Report for the Electricity Commission

JULY 2009

Prepared By:

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This Report covers technical data relating to thermal generating plants and is based on the facts known to PB at the time of preparation. This report does not purport to contain all relevant information on all plant. PB has made a number of assumptive statements throughout the Report, and the Report is accordingly subject to and qualified by those assumptions. The uncertainties necessarily inherent in relying on assumptions and projections mean that it should be anticipated that certain circumstances and events may differ from those assumed and described herein and that such will affect the results.

***PB** Quality System:*

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Prepared by :	Neil Wembridge, Luc Poloni, Nigel McGimpsey, Noel Hall
Reviewed by :	Nick Barneveld
Approved by :	Nick Barneveld
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1 Introduction

1.1 Background

The following paragraph is taken from the email received from the Electricity Commission, dated Wednesday 20th May 2009:

> "…New Zealand has around 2500 MW of thermal installed capacity operating today. Some of the plants are more than 35 years old and could face major refurbishment in the near future to keep their high availability and reliability. The Electricity Commission (Commission) Generation Expansion Model is capable of providing least cost build schedule of new power stations under various scenarios however the decommissioning date of the existing power stations is an exogenous decision and therefore is subject to uncertainty. To date the decommissioning of the existing plants has been varied across the generation scenarios to reflect the uncertainty. In view of refining the assumptions of the next grid planning assumptions, the Commission needs advice on the possible dates of the decommissioning of the existing thermal power stations or, if cost effective, the refurbishment required to extend the operating life of the plants…"

1.2 Tasks

In order to provide the required information to the Commission, this study has been divided into five main tasks.

- Task 1 – Provides an overview of thermal plant in New Zealand including a general description of the power station along with a discussion of when it was commissioned, annual operating hours and major outages experienced by the plant.
- Task 2 – Establishes world trends in the operating life of thermal plant with and without major life extension refurbishment.
- Task 3 – Discusses major maintenance and refurbishment costs for thermal plant.
- Task 4 – Estimates decommissioning dates for thermal plant in New Zealand for two scenarios, with and without a major life extension refurbishment.
- Task 5 – Demonstrates the economic impact of a life extension refurbishment by estimating the Long Run Marginal Cost of generation for thermal plant in New Zealand.

1.3 Scope

Thermal plant included in the NZ asset review tasks (tasks 1, 4 and 5) are as follows:

- Huntly Power Station - units 1 to 4
- Huntly CCGT - E3p
- Huntly OCGT - P40
- Taranaki CCGT
- Otahuhu B CCGT
- New Plymouth
- Southdown CCGT
- Southdown E105
- Whirinaki dry year reserve plant

This study focuses on physical life capacity and not technical or economic redundancy. For example, New Plymouth PS is not run for fuel availability and economic reasons but still has physical life.

2 NZ thermal plant descriptions

2.1 Introduction

2.1.1 EC brief

"*Provide a quick description of each of the existing thermal power stations in New Zealand... The descriptions should comprise information on the commissioning date, estimate of the number of hours that the plant has operated, major outages and any other relevant information that could impact the life of the plants*."

2.1.2 PB approach

Descriptions of the existing thermal power stations were retrieved from PB's in-house databases, from the owner web sites, and from other public domain sources.

Estimates of the operating hours of each plant were retrieved from public domain sources such as the CDS[1] (centralised data set), Energy Link and PB in-house databases where available. Otherwise, PB has calculated operating hours to date for each plant based on high level estimates of operating regime (e.g. baseload, intermediate, peaking) and availability over the life of the plant to date.

2.2 Huntly Power Station - Units 1 to 4

2.2.1 Plant description

Huntly Power Station units 1 – 4 are four identical 250 MW (gross), conventional, subcritical, Rankine cycle, thermal generation units (boiler and steam turbine). The units' boilers are dual fuelled and designed to burn natural gas and sub-bituminous coal. Heat rejection from the steam turbine condensers is to the Waikato River using once-through river water cooling.

[1] The Electricity Commission's Modelling and Forecasting group provides historical and forecast information to the Commission and to the wider industry. The Commission is required to establish, maintain, and publish a Centralised Dataset (CDS) under Part F of the Electricity Governance Rules. The purpose of the Centralised Dataset is to support efficient planning processes by ensuring the collection and maintenance of historical information required to make decisions on transmission and transmission alternatives. The Centralised Dataset contains historical metering, market related, hydrological, and network related data. The Dataset is available on request.

2.2.2 Commissioning date

The commitment to build Units 1 - 4 was made in 1973, the main plant contracts awarded in 1974, and the first (Unit 1) of the four 250 MW generating units was commissioned in 1982. The remaining units followed in successive years with Unit 4 commissioned in 1985. The design of these units is therefore around 35 years old and the plant is nominally 25 years old. The original design life is understood by PB to be 25 years and 200,000 equivalent operating hours (EOH) which are industry standard design limits. In addition to normal generation, EOH are also consumed by starts, stops and trips.

2.2.3 Operating hours

The following operating hours, up to and including the year 2008 have been derived from PB's in-house databases and data are extracted from the Electricity Commission's Centralised Dataset (CDS).

- Unit 1 153,000 hours
- Unit 2 155,000 hours
- Unit 3 142,000 hours
- Unit 4 143,000 hours

In terms of operating hours the main plant items have used approximately 71 – 78% of their design service life of 200,000 hours.

2.2.4 Major outages

- Conventional Rankine cycle, thermal generation units are subject to planned maintenance at defined intervals. Planned maintenance normally occurs annually, at the time of lowest electricity demand. In New Zealand this is over the Christmas/New Year school holiday period. Annual planned maintenance varies in scope, ranging from statutory inspections to major overhauls. Plant like Units 1 – 4 are normally subject to major overhaul once every 4 – 6 years.
- In early 1999 Unit 3 generator transformer was extensively damaged as a result of internal explosions and subsequent fire. The fire, heat and water damage extended beyond the generator transformer, effecting Unit 3 Isolated phase bus duct, the unit transformer, a station transformer, the turbine hall building behind and above Unit 3 generator transformer and the ground surrounding the area. The unit was out of service for several months.

2.2.5 Other life impacts

- Huntly Power Station Units 1 – 4 were designed primarily to burn Waikato coal but also designed to fire natural gas, and both coal and gas can be fuelled simultaneously in the boilers. Coal was expected to be used to provide the energy for 75% of the generation in a normal year with gas fuel being used to provide the balance. Historically, natural gas supply and pricing economics resulted in Units 1 - 4 operating predominantly on natural gas in a base load regime from the time the first unit was commissioned in 1982, and until 2002. However, during that period the station routinely burned sufficient coal to ensure that a coal firing capability was maintained.

From 2002 onwards the coal to gas ratio steadily increased and in February 2003 the final determination of the Maui gas field reserves resulted in Genesis' entitlement to gas supply for Huntly Power Station being reduced by 25%. This, along with an increase in the demand for electricity, led to the station now using approximately 90 – 95% coal and 5 – 10% natural gas. Around 50% of the coal consumed at Huntly is now imported from Indonesia.

There are two implications of this fuel type transition:

Firstly, natural gas is a relatively benign fuel in terms of boiler maintenance needs, having none of the inert ash components associated with coal. Coal ash is erosive and may also foul heat exchange surfaces in the boiler. It must also be captured, collected and disposed of. With gas firing there are no such issues and the life of fire-side surfaces in the boiler, and ash handling plant, is typically prolonged compared to coal fuelled operation. The boiler fireside surfaces and ash capture and handling equipment are therefore estimated to have more remaining life than the unit service hours indicate.

Secondly, the coal handling plant and coal combustion preparation equipment is estimated to have more remaining life than the unit service hours indicate. It is estimated that the pulverising mills in particular, and the associated coal feeders, pulverised fuel pipes, and burners have probably consumed less than half their nominal 200,000 hour design life. Note with respect to the pulverising mills that certain high wear components have an expected design life much shorter than 200,000 hours, and regular refurbishment and replacement is an accepted and normal maintenance feature for such items.

- Control systems replacement at 12 – 15 year intervals is expected due to technical obsolescence.

2.3 Huntly Power Station – Unit 5 CCGT

2.3.1 Plant description

Huntly Power Station Unit 5 is a natural gas fuelled, 385 MW capacity, single shaft, combined cycle gas turbine plant (CCGT) using a Mitsubishi 701F3 gas turbine. The steam turbine condenser is cooled by a wet-dry (hybrid) type cooling tower equipped with plume abatement capability.

2.3.2 Commissioning date

Genesis proposed to establish a new CCGT power plant within the boundaries of the Huntly Power Station site in late 2000. The commitment to build Unit 5 was made in 2004 and it was commissioned in June 2007.

The 701F came to the market in the early 1990s and the F3 is understood to be a third generation machine. The design of the unit is therefore estimated to be around 7 years old and the plant is nominally 2 years old, compared to a nominal design life of 25 years.

2.3.3 Operating hours

The operating hours given in the following Table 2.1 are derived from data extracted from the Electricity Commission's Centralised Dataset (CDS).

Table 2.1 Huntly Unit 5 Operating hours

Year	Estimated number of hours of operation
2007 (commissioned June)	5,323
2008	8,283
TOTAL	**13,606**

2.3.4 Major outages

- Gas turbine and combined cycle plant is also subject to planned maintenance at defined intervals. Planned maintenance on the hot components of gas turbines in particular occurs at predetermined operating hour intervals, typically with inspections and minor maintenance at 12,500 hours, and with overhauls and major maintenance at 25,000 hours. Other planned maintenance for other components of the plant normally occurs annually, as for Huntly Units 1 – 4 above.
- There have been no planned or unplanned major outages to date.

2.3.5 Other life impacts

- Control systems replacement at 12 – 15 year intervals is expected due to technical obsolescence.

2.4 Huntly Power Station – Unit 6 OCGT

2.4.1 Plant description

Huntly Power Station Unit 6 is a dual fuelled, 48 MW capacity, open cycle gas turbine plant, designed to burn natural gas and diesel (distillate), using the General Electric LM6000 Sprint^{TM} aero derivative gas turbine.

2.4.2 Commissioning date

The commitment to build Unit 6 was made in 2003 and it was commissioned in June 2004.

The GE LM6000 Sprint^{TM} model installed at Huntly is understood to have been introduced in 2000. The design of Unit 6 is therefore around 9 years old and the unit is nominally 5 years old, compared to a design life of around 25 years.

2.4.3 Operating hours

The operating hours given in the following Table 2.2 are derived from data extracted from the Electricity Commission's Centralised Dataset (CDS).

Table 2.2 Huntly Unit 6 Operating hours

Year	Estimated number of hours of operation
From May 2004	2,373.5
2005	4,883.5
2006	6,867.5
2007	3,080.5
2008	3,213.5
TOTAL	**20,418.5**

2.4.4 Major outages

- Gas turbine plant is subject to planned maintenance at defined intervals. Planned maintenance on the hot components of gas turbines in particular occurs at predetermined operating hour intervals. The LM6000 maintenance inspection and overhaul periods are typically at 12,500 operating hours (bore-scope visual inspections), 25,000 operating hours (overhaul), and 50,000 operating hours (hot gas path replacement). The 50,000 hour hot gas path replacement effectively zero-times a gas turbine.
- Other planned maintenance normally occurs annually, as for Huntly Units 1 – 4 above. Maintenance overhaul requirements on the pressure parts are typically at 4 yearly intervals. This is primarily driven by statutory inspection requirements.
- There is potential for future gas turbine replacement into the package with a more efficient LM 6000 model as GE continues gas turbine development.
- There have been no other planned or unplanned major outages to date.

2.4.5 Other life impacts

- Control systems replacement at 12 – 15 year intervals is expected due to technical obsolescence.

2.5 Taranaki CCGT

2.5.1 Plant description

Taranaki Combined Cycle Plant is a natural gas fuelled, 377 MW capacity (357MW at commissioning), single shaft, combined cycle gas turbine plant (CCGT) using the Alstom GT26 gas turbine. The steam turbine condenser is cooled by a wet-dry (hybrid) type cooling tower equipped with plume abatement capability.

2.5.2 Commissioning date

The turnkey contract to build the Taranaki Combined Cycle Plant commenced in November 1995 and the plant entered commercial operation following practical completion in July 1998.

The GT26 gas turbine was developed by ABB, prior to its takeover by Alstom, and was launched commercially in 1993. The Taranaki plant was supplied with a GT26A gas turbine variant, which was the first release of that design variant of the GT26. ABB offered an upgrade to the 'B' rating hot gas path specification. This upgrade was completed during a major overhaul, referred to as a 'C' class inspection, in 2001. The specification of the Taranaki gas turbine is now classed as GT26AB to indicate that it is an 'A' rated engine, uprated with 'B' hot gas path components.

The Taranaki Combined Cycle Plant was the first three-pressure, single-shaft unit to be installed in the world, and the fourth GT26 to be installed. The term "three-pressure" refers to the heat recovery steam generator (HRSG) and steam turbine, or Rankine cycle part of the "combined cycle". In this configuration, steam is produced at three different pressures, and expanded through three different parts of the steam turbine. The term "single-shaft" means that the gas turbine, steam turbine and electric generator are coupled together to form a single shaft.

The design of the unit is estimated to be around 12 years old and the plant is 11 years old, compared to a nominal design life of around 25 years.

2.5.3 Operating hours

The operating hours given in the following Table 2.3 are derived from data extracted from the Electricity Commission's Centralised Dataset (CDS).

Table 2.3 Taranaki Combined Cycle Plant operating hours

Year	Estimated number of hours of operation
From 01/07/1998	3,948
1999	7,224
2000	7,888
2001	7,632.5
2002	7,754.5
2003	7,455.5
2004	6,700
2005	7,188
2006	7,670
2007	7,684
2008	6,240.5
TOTAL	**77,385**

2.5.4 Major outages

- Gas turbine and combined cycle plant is also subject to planned maintenance at defined intervals. Planned maintenance on the hot components of gas turbines in particular occurs at predetermined operating hour intervals, typically with inspections and minor maintenance at 12,000 hours, and with overhauls and major maintenance at 24,000 hours. Other planned maintenance for other components of the plant normally occurs annually.

Given the above operating hours, it is expected that the Taranaki Combined Cycle Plant has by now had three major maintenance overhauls, at 25,000 hours, 50,000 hours and 75,000 hours.

- TCC was offline between mid March and late April 2001[2].
- Planned 'C' level inspection in April 2003[3] including an outage lasting approximately one month.
- A major 'C' level inspection was missed in February 2005.
- A major outage was experienced for approximately two months from February 2008. This included routine maintenance and an upgrade including a 1% improvement in efficiency[4].
- Alstom have declared that there were a number of type faults on early installations of these machines (GT26A variant). The faults were mainly dealt with during planned outages impacting availability not reliability or operating life.
- There have been no other major outages.

2.5.5 Other life impacts

- Control systems replacement at 12 – 15 year intervals is expected due to technical obsolescence.

2.6 Otahuhu B CCGT

2.6.1 Plant description

Otahuhu B Power Station is a natural gas fuelled, 404 MW capacity (380 at commissioning), single shaft, combined cycle gas turbine plant (CCGT) using the Siemens V94.3A(2) gas turbine. The steam turbine condenser is cooled by a wet-dry (hybrid) type cooling tower equipped with plume abatement capability, and using seawater make-up from the adjacent estuary.

2.6.2 Commissioning date

Otahuhu B Power Station was commissioned in December 1999.

The Siemens V94.3A(2) gas turbine is understood to be a first generation machine, in effect a "first of its kind". The design of the unit is therefore estimated to be around 10 years old and the plant is 10 years old, compared to a nominal design life of around 25 years.

2.6.3 Operating hours

The operating hours given in the following Table 2.4 are derived from data extracted from the Electricity Commission's Centralised Dataset (CDS).

[2] http://www.med.govt.nz/upload/30408/x006.pdf
[3] http://www.contactenergy.co.nz/web/pdf/financial/2003_queenstown_tcc.pdf
[4] http://www.contactenergy.co.nz/web/pdf/Community/CEL_13914_ComUpdate_Taranaki_v7LR.pdf

Table 2.4 Otahuhu B operating hours

Year	Estimated number of hours of operation
1999	1,792.5
2000	3,170.5
2001	7,035
2002	5,978.5
2003	7,470.5
2004	8,083
2005	6,993.5
2006	8,364
2007	7,952
2008	6,880
TOTAL	**63,719.5**

2.6.4 Major outages

- As for Huntly Unit 5 and the Taranaki Combined Cycle Plant, gas turbine and combined cycle plant is also subject to planned maintenance at defined intervals. Planned maintenance on the hot components of gas turbines in particular occurs at predetermined operating hour intervals, typically with inspections and minor maintenance annually at an inspection interval of approximately 8,300 hours, and with overhauls and major maintenance at 25,000 hours. Other planned maintenance for other components of the plant normally occurs annually.
- While Otahuhu B was being returned to service after its first six-month inspection in 2000 its generator transformer failed and had to be returned to Brazil for repair.[5] It was out of service for about six months[6], returning to service in late January 2001.
- Otahuhu B has had three major outages as follows:
  - 25,000 EOH service late 2002, early 2003[7];
  - 48,000 EOH outage in late 2005 and
  - 73,000 EOH outage in late 2008.
- The HRSG was subjected to extensive weld inspections prior to take over, due to poor weld quality it is likely that the HRSG will be subjected to some forced outages as a result of tube failures.[8] Recently some issues have been identified with the main steam and hot reheat pipe work systems P91 material, an ongoing weld inspection program will be required to manage these issues[9].

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5 http://www.contactenergy.co.nz/web/pdf/financial/2001_halfyearreport_msgtoshares.pdf
6 http://www.stuff.co.nz/the-press/business/475634
7 http://www.contactenergy.co.nz/web/pdf/financial/2002_annualreport_full.pdf
8 http://www.contactenergy.co.nz/web/mediaandpublications/pressreleases/1999/19990527_01?vert=mp
9 http://www.findata.co.nz/Markets/NZX/3470/GENERAL_CEN_CEN_Otahuhu_B_Update.htm

2.6.5 Other life impacts

- Control systems replacement at 12 – 15 year intervals is expected due to technical obsolescence.

2.7 New Plymouth Power Station

2.7.1 Plant description

New Plymouth Power Station originally comprised five identical 120 MW (gross), conventional, subcritical, Rankine cycle, thermal generation units (boiler and steam turbine). The units' boilers are dual fuelled and designed to burn natural gas and fuel oil. Heat rejection from the steam turbine condensers is to the ocean using once-through seawater cooling.

The station was originally designed to burn coal, but in May 1970, after the discovery of the Maui natural gas field, the boilers were redesigned to burn fuel oil and natural gas. The station was oil-fuelled for the first two years of operation, but switched to Kapuni gas in 1976 and to Maui gas in 1979. The oil-firing systems were decommissioned prior to 1993, but were reinstated in 2005 to allow the station to run on either natural gas or fuel oil in the case of an emergency.[10,11,12]

Prior to March 1999, two units were derated to around 115 – 120 MW gross owing to generator stator insulation deterioration. In April 1997 Contact was granted non-notified consents for the Otahuhu B CCGT plant, and in the process of securing these consents Contact entered in to an agreement with Greenpeace to mothball one of its five New Plymouth units at the Commissioning Date (of Otahuhu B) and to mothball a second New Plymouth unit no later than 5 years after the Commissioning Date. This implies that the first unit was mothballed in December 1999, and the second in December 2004. The station capacity is now stated by Contact to be 330 MW (gross), provided by three units.

Asbestos was discovered in the power station in late 2007, and a decision was made to cease operations at the site, with the last day of generation on 25 September 2007. Asbestos removal was undertaken during the later part of 2007 and early 2008, however the station was re-opened in June 2008 to help ease winter power shortages.[13] Its future status remains uncertain.

2.7.2 Commissioning date

The commitment to build New Plymouth Power Station was made in the mid 1960s and construction began in 1968. The first of the five 120 MW generating units was commissioned in March 1974 and the last in December 1976. The design of these units is estimated to be around 40 years old and the plant is nominally 34 years old, compared to a design life of around 25 years.

[10] Electricity Corporation of New Zealand Limited, New Plymouth Thermal Power Station (brochure dated 7/89)
[11] ECNZ, A Guide to the New Plymouth Thermal Group, New Plymouth (brochure dated 8/93)
[12] Contact Energy Ltd, Thermal Electricity, brochure dated 2007
[13] Taranaki Regional Council, New Plymouth Power Station Monitoring Programme Annual Report 2007-2008, Technical Report 2008–42, October 2008

2.7.3 Operating hours

Historical ECNZ documents describe the nominal design life of New Plymouth as 100,000 hours based on 25 years operation at an average net capacity factor (NCF) of 50%. Assuming that the 'older' (in terms of operating hours) units were the ones taken out of service, it is estimated that the remaining units have accumulated 85,000 – 100,000 operating hours, or 85 – 100% of their nominal design life.

2.7.4 Major outages

- As for Huntly Power Station Units 1 – 4, conventional Rankine cycle, thermal generation units are subject to planned maintenance at defined intervals. Planned maintenance normally occurs annually, at the time of lowest electricity demand. In New Zealand this is over the Christmas/New Year school holiday period. Annual planned maintenance varies in scope, ranging from brief statutory inspections to major overhauls. Plants like the New Plymouth units are normally subject to major overhaul once every 4 – 6 years.

  Given the plant's uncertain future, and its status as an emergency generator to ease power shortages, it is likely that all major maintenance is being deferred and only sufficient maintenance is being carried out to ensure adequate availability for an emergency generation role.

  This puts the New Plymouth plant in a similar situation to that of Marsden A during the late 1980s and early 1990s, and it seems likely that a need for major maintenance would trigger a decision to decommission the plant. Such a decision was made in late 2007, but subsequently rescinded.

2.7.5 Other life impacts

- As noted previously, and as is typical for all power generation and industrial process plant, controls replacement at 12 – 15 years is expected due to obsolescence. Such a requirement would likely trigger a decision to decommission the plant.

2.8 Southdown cogeneration (122MW)

2.8.1 Plant description

The Southdown Cogeneration Facility is a natural gas fuelled, 122 MW (net) combined cycle cogeneration plant. It comprises two, nominally 45 MW General Electric LM6000 PC aero derivative gas turbine generators, two heat recovery steam generators (HRSG) and one nominally 35 MW steam turbine. A low pressure (LP) steam turbine extraction provides approximately 24 t/h of process steam to industry (Carter Holt Harvey paper mill). Particular features of the plant are:

- The HRSGs are equipped for duct firing to provide steam to meet the cogeneration steam demand and to maximise generation from the steam turbine. The duct firing capability also enables a single LM6000/HRSG unit to provide some steam turbine generation and cogeneration steam with the second LM 6000 out of service.

- There is no bypass stack between the gas turbine and the HRSG, however the HRSG are a once through design that can potentially be run dry to enable open cycle operation of the LM6000 should the steam turbine be out of service.

The steam turbine condenser is a wet surface air cooled condenser (ACC). Its saturated outlet conditions provide the visible steam plume often observed at the Southdown facility.

2.8.2 Commissioning date

The Southdown Cogeneration Facility was commissioned progressively from December 1996 to September 1998, by TransAlta and purchased by Mighty River Power (MRP) in December 2002[14]. The LM6000-PC model was introduced in 1997[15]. The design of the gas turbine unit is therefore estimated to be around 12 years old and the plant is 11 years old, compared to a nominal design life of around 25 years.

2.8.3 Operating hours

The operating hours given in the following Table 2.5 are derived from data extracted from the Electricity Commission's Centralised Dataset (CDS).

Table 2.5 Southdown Cogeneration Facility operating hours

Year	Estimated number of hours of operation	Cumulative operating hours
1998	8,594	8,594
1999	8,744.5	17,338.5
2000	8,675	26,013.5
2001	8,684.5	34,698
2002	8,760	43,458
2003	8,718.5	52,176.5
2004	8,265	60,441.5
2005	7,447.5	67,889
2006	6,591.5	74,480.5
2007*	6,780.5	81,261
2008*	6,605.5	87,866.5
TOTAL	**87,866.5**	

*The operating hours in 2007 and 2008 include the output from a third gas turbine generator ("Southdown E105" – see Section 2.9) added in 2007.

The additional gas turbine generator added in 2007 is a peaking plant and is estimated to have generated around 500 – 1,000 hours in each year of operation

[14] http://www.mightyriverpower.co.nz/Generation/PowerStations/CoGeneration/Southdown/Default.aspx?id=1414
[15] GE Power Systems, GE Aeroderivative Gas Turbines – Design and Operating Features, GER-3695E, 10/00

to date. On that basis the Southdown Cogeneration Facility is estimated to have accumulated around 86,000 operating hours.

2.8.4 Major outages

- As for Huntly Unit 6, the LM6000 maintenance inspection and overhaul periods are typically at 12,500 operating hours (bore-scope inspections), 25,000 operating hours (overhaul), and 50,000 operating hours (hot gas path replacement). The 50,000 hour hot gas path replacement effectively zero-times a machine.
- Maintenance overhaul requirements on the pressure parts are typically at 4 yearly intervals. This is primarily driven by statutory inspection requirements.

2.8.5 Other life impacts

- Controls replacement at 12 – 15 year periods is expected due to obsolescence.
- There is potential for future gas turbine replacement into the package with a more efficient LM 6000 model as GE continues gas turbine development. However the Rankine cycle part of the combined cycle plant is unlikely to have a significant change in performance as the thermodynamic bounds of the maximum steam pressure and temperature and heat rejection are fixed.
- There is limited potential for future refurbishment of the steam turbine with improved blading design for increased isentropic efficiency. However unless the air cooled condenser is replaced to enable a significant improvement in the steam turbine backpressure there will not be any major potential for performance improvement.

2.9 Southdown E105

2.9.1 Plant description

The Southdown E105 gas turbine is a nominally 45 MW open cycle gas turbine installation using a General Electric LM6000 gas turbine. It is installed to provide peak load generation and also to provide synchronous condensing capacity (voltage support) to the national electricity grid.

The E105 LM6000 gas turbine package was a surplus zero-time engine manufactured in 2001, and that has been converted to a specification with water injected NOx emission control. The gas turbine is also provided with SPRINT™ water injection to provide an additional peak generation capability of approximately 5 MW. Water injection increases the fuelled hour maintenance costs owing to increased erosion on the low pressure (LP) blading.

Synchronous condensing duty is enabled by a gearbox incorporating a clutch. The gas turbine is used to run the generator up to speed, the generator is synchronised to the grid, the clutch is then disengaged and gas turbine is shut down. The E105 installation is the first 50 Hz LM6000 to be provided with a clutched gearbox for synchronous condensing duty.

2.9.2 Commissioning date

The E105 LM6000 was commissioned in 2007. Although the LM6000-PC model was introduced in 1997, gas turbine models are typically upgraded from time to time as technology develops. The design of the gas turbine unit is therefore estimated to be around 3 - 5 years old and the plant is 2 years old, compared to a nominal design life of around 25 years.

2.9.3 Operating hours

As noted in section 2.8.3 and above, the E105 machine ("the additional gas turbine generator added in 2007") is a peaking plant and is estimated to have contributed around 500 - 1000 hours in each year of operation to date. On that basis the E105 machine is estimated to have accumulated around 2,000 operating hours.

2.9.4 Major outages

- As for Huntly Unit 6 and the Southdown Cogeneration Facility, the LM6000 maintenance inspection and overhaul periods are typically at 12,500 operating hours (bore-scope inspections), 25,000 operating hours (overhaul), and 50,000 operating hours (hot gas path replacement). The 50,000 hour hot gas path replacement effectively zero-times a machine. MRP carry a rotatable spare gas turbine to minimise outage time on the gas turbine.

2.9.5 Other life impacts

- There is potential for the retrofit of a Heat Recovery Steam Generator (HRSG) to the E105 gas turbine to recover waste heat from the 450°C exhaust temperature. There are two primary means of using heat recovered:
  - One option is to integrate with the existing Southdown Cogeneration Facility to displace duct firing of the existing HRSGs. This would yield a heat rate enhancement for the entire facility but would not increase total generation from the site.
  - The alternative is the development of a stand-alone CCGT installation for E105 with the addition of a steam turbine and cooling tower. This would not integrate with the existing cogeneration facility but would provide additional generation. Without additional duct firing this would provide approximately 12 MW of steam turbine generation.
- Control systems replacement at 12 – 15 year intervals is expected due to technical obsolescence.

2.10 Whirinaki Power Station

2.10.1 Plant description

The Whirinaki Power Station is a 155 MW, diesel fuelled, open cycle gas turbine power station using three Pratt & Whitney FT8 Twin Pac gas turbine generators. The FT8 gas turbine is an aero-derivative gas turbine derived from the Pratt &

Whitney JT8D turbofan aircraft engine. In the TwinPac configuration, two FT8 aero-derivative gas turbines, each rated at around 26 MW are directly connected to each end of a centrally located synchronous generator.

The gas turbines need water injection to control exhaust emissions to meet consent requirements. Four on-site staff manage the plant, which can also be operated remotely from Contact's Otahuhu Power Station.

The Whirinaki plant provides reserve generation for use during dry periods when hydro lake inflows are abnormally low and in cases where additional system support is required such as when a generating plant has a major outage. Contact Energy Limited operates and maintains the plant on behalf of the New Zealand Government.

The site was previously occupied by a 220 MW power station, which began operation in 1978. This comprised four Pratt & Whitney FT4 Twin Pac gas turbine generators. This diesel fuelled power plant was an expensive electricity generator and was operated very rarely. In 1993, one Twin Pac was relocated to construct a cogeneration plant at the Te Awamutu dairy factory. The remaining units were purchased in 2001 by Edison Mission Energy and relocated for use in the Valley Power project in Victoria (Australia), in which Contact subsequently invested.

The original FT4 units were therefore 23 years old when decommissioned in New Zealand, but have continued in service (peaking duty) at their new location in Australia.

2.10.2 Commissioning date

Following national power shortages in 2001 and 2003 due to low hydro lake levels, the New Zealand Government commissioned Contact Energy to build reserve generation on the Whirinaki site.

Construction of the Whirinaki plant began in October 2003, and the three gas turbines were all successfully tested in March – April 2004. The first FT8 TwinPac was introduced in 1990 but the models installed at Whirinaki are expected to have been current upgrade models, with a design around 2 – 3 years old.

The design of the gas turbine units are therefore estimated to be around 7 - 8 years old and the plant is 5 years old, compared to a nominal design life of around 25 years.

2.10.3 Operating hours

The operating hours given in the following Table 2.6 are derived from data extracted from the Electricity Commission's Centralised Dataset (CDS).

Table 2.6 Whirinaki operating hours

Year	Estimated number of hours of operation
2004	328
2005	93
2006	236

2007	17.5
2008	1,248.5
TOTAL	**1,923**

In 2008, Whirinaki operated more than expected due to below average southern hydro-lake levels resulting in high wholesale electricity market prices.

2.10.4 Major outages

- The FT8 maintenance inspection and overhaul periods are typically at 12,500, 25,000 and 37,500 operating hours for hot section inspection and refurbishment and 50,000 operating hours for major shop inspection and refurbishment. The 50,000 hour hot gas path replacement effectively zero-times a machine.

2.10.5 Other life impacts

- Control systems replacement at 12 – 15 year intervals is expected due to technical obsolescence.

3 World trends in thermal plant life

3.1 Introduction

3.1.1 EC brief

"*Provide a brief quantitative review of the world trends of the life of coal and gas power stations. If possible this might include a probability distribution of the coal and gas plant life using international historical data. Two plots could be provided for each of the technology, one without any refurbishment and the other with refurbishment (i.e. this will provide the average life extension given by the refurbishment). Along with this data a description of the key factors influencing the plant life should be provided*."

3.1.2 PB approach

The main information sources were public domain, such as the North American Electric Reliability Corporation (NERC) Generating Availability Data System (GADS), the US Department of Energy (DOE) and National Energy Technology Laboratory (NETL), the UK Department of Trade & Industry (DTI), the International Energy Agency (IEA), supplemented by PB in-house databases in NZ and the UK.

Generic OEM (Original Equipment Manufacturer) guidelines and published material were referenced in addition to actual installation examples.

The information obtained was used to develop a distribution of plant life against plant technology (CCGT and coal steam plant) and plant which has undergone major refurbishment to extend the original design life. Extrapolation and interpolation of the data points has been necessary because each installation is inherently different and original design lives vary depending on technology used, size of asset and location characteristics such as fuel type and characteristics.

3.1.3 Definitions

In order to discuss how long a plant will operate for it is important to discuss the following widely used phrases.

Operating life/Economic life/Design life

The operating life of a power station can be defined as the length of time in years after commissioning that a plant will generate, or has been generating electricity before being decommissioned.

The economic life of a plant refers to a prediction of how long it will be generating based on specific economic criteria such as remaining profitable. The economic life is usually discussed within the context of a forecast of certain financial factors such as future electricity prices, and fuel costs. A plant reaching the end of it's economic life suggests it would then be decommissioned, however there are situations where the plant may be retained in an operational state, a state of readiness to return to service, or mothballed.

The design life refers to the length of time used in engineering design and manufacture specifications for the plant. Design life is typically defined in terms of operating hours which are then translated into an expected calendar lifetime depending on the operating regime – base load, peaking etc. A plant could be designed to operate for 25 years in a specific operating regime which, for example, dictates the use of specific alloys or thickness of heat shielding equipment. A change in operating regime can affect the assets calendar lifetime.

Heat rate

When forecasting plant life, it is useful to consider impacts of time and operating regime on the heat rate or efficiency of the power station. Heat rate[16] is usually measured as kJ/KWh, and indicates the amount of fuel energy (kJ) required to generate a unit of electricity (kWh). Therefore the lower the heat rate the higher the efficiency of the plant.

Plant heat rate or efficiency will degrade over time with use due to the wearing of components. Routine maintenance and overhauls are designed to minimise the effects of degradation and maintain the heat rate as close to the original design criteria as possible over the life of the plant. Restoring the heat rate back to the original design or better, requires significant investment and often involves replacement of the majority of components with technically superior equivalents.

Plant heat rate can be one of the major factors influencing plant life, as efficiency ultimately impacts economic viability. If the heat rate has degraded to the extent that significant capital investment is required to restore the heat rate and the benefits of such investment do not provide a positive economic return, a decision can be made to decommission the plant.

3.2 Factors influencing the plant life

3.2.1 General

It has been suggested that:

"In most cases coal-fuelled power plant can have its life extended by a factor of 50-100% over the original design life. This arises in part from the conservative assumptions made in the original design process and in part is a consequence of well-managed repair and maintenance in these plants"[17].

PB's perception is that this factor has resulted in many power plants the world over operating well beyond their nominal 25 – 30 year design life.

[16] A measure of efficiency
[17] Fleming & Foster, IEA Coal Research, Aging of Coal-fired Power Plants, 2001

3.2.2 Design life

Power plant equipment design life is typically specified as 25 years operational life and 200,000 hours. A number of hot, warm and cold starts will also be specified. An EOH penalty will be associated with each start, stop or trip event.

The 200,000 hour life is primarily related to reasonable extrapolation limits of creep life[18] testing data[19] for high temperature materials. Power station buildings and structures are designed to have a minimum life of 50 years for general building design code compliance.

3.2.3 Life limiting factors

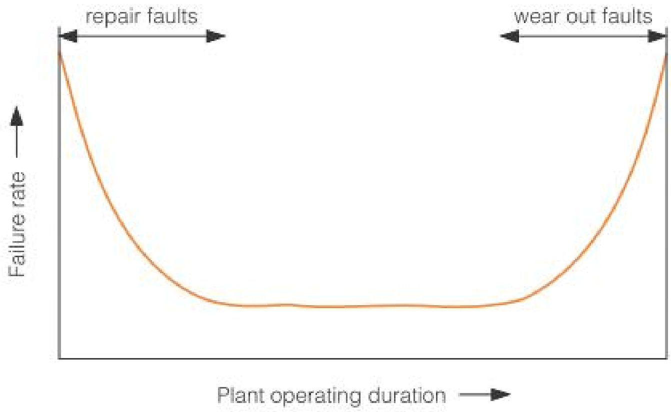
For an operating power plant the main technological life limiting issues are:

- The creep life of high temperature components. This is typically limited to boiler pressure parts, high temperature pipework and the heavy wall thickness and/or non-symmetrical high pressure (HP) steam turbine components (e.g. emergency stop valves, bypass valves, governor valves, steam chests, HP cylinder casings, HP nozzle rings). It may include the HP turbine rotor, both shaft and disks.
- Fatigue life of rotating components, components subject to repeated temperature change, and components subject fluctuating loads and vibration.
- Erosion – primarily related to gas side solid particle erosion of the boiler pressure parts. However water and steam side erosion can also be an issue, particularly in low pressure steam turbines.
- Corrosion
- Technological obsolescence – primarily an issue with controls and instrumentation and electrical systems.
- Environmental compliance – resource consents are only granted for limited periods and emission compliance, particularly if the environment is subsequently degraded, may impose major emissions control equipment (e.g. flue gas desulfurization (FGD)).

"Generally all components show a classic 'bathtub' failure curve (see Figure 3-1). *At long operating times, failure rates are high, as components 'wear out' due to time dependent failure mechanisms. At short operating times, components also show high failure rates due to shortcomings in quality control, which have allowed components containing defects to go into service. Such increases in failure rate were once common after breakdowns and repair outages, but have been reduced by increasing awareness of the downstream costs of poor inspection and quality control procedures. Between these high failure rates lies a region of low failure rates, related only to random events.*

[18] the gradual deformation of a material, especially a metal or alloy, due to constant stress, high temperature, etc.
[19] Creep data obtained for newer materials is usually based on ongoing tests that are, at the time of that materials' inclusion in a plant design, at much less than the 200,000 hour design life, so extrapolations based on the long term behaviour of similar materials are usually required to provide the design data.

Figure 3-1 Bath tube failure curve



Large utilities power plant operators tend to produce power with their newer plant, which offers higher efficiency, with older plant being used for peak load. Plant operating continuously, base load service, generally suffers creep damage while plant operating peak load service also experiences thermal fatigue (Fideli, 1998). Thus, as plant ages, it is increasingly at risk of failure both from time dependent creep failure mechanisms and load cycling dependent fatigue."[17]

Evaluation of remnant life is required to determine any economic life extension of power plant.

"Whilst maintenance costs will increase with age in power plant, this is normally more than offset by the decrease in capital costs resulting from depreciation. In most cases, the decision to replace power generation plant by new equipment is based on the savings to be realised from increased efficiency, rather than any technical difficulty in extending plant life (Wheeler, 1999; Verma and others, 1999)."[17]

The economic drivers for plant life extension are under-pinned by the refurbishment costs, increasing O&M costs, and increasing fuel costs for old and less efficient plant. The existing subcritical Rankine cycle power plant in NZ (New Plymouth and Huntly power stations) is typically 33 - 36% efficient (on a higher heating value (HHV) basis). The latest generation of ultra-supercritical coal-fuelled plant is currently approaching 42 – 44%.

3.2.4 Conclusion

Power station plant can be the proverbial "grandfathers axe" – new heads and new handles over the years but it's the same axe. Likewise, operating life can be maintained well beyond the original design life with the replacement and refurbishment of equipment. This is well illustrated with the age of the thermal power plant fleet, as shown in Section 3.4.

3.3 New Zealand experience

Recent (past 50 years) New Zealand experience has seen two thermal power plants reach the end of their useful lives and be eventually demolished: Meremere and Marsden A power stations.

3.3.1 Meremere Power Station

Following a report commissioned in 1952, it was decided in 1955 to build a 180 MW (gross) coal-fuelled, subcritical Rankine cycle, thermal power plant at Meremere, in the northern Waikato. Construction began in 1956 and power from the first of the stations original 6 machines began to flow into the North Island electricity system in August 1958. In 1965 it was decided to install a seventh steam turbine generator and this was commissioned in April 1967.

After approximately 23 years operation it was decided in the early 1980s to refurbish the Meremere plant to extend its operating life by a further 10 years or 60,000 hours. At the time it was expected that during its extended life, the station would be used principally for ensuring security of supply to the national grid. Under such circumstances the annual load factor (≈ Capacity Factor in today's terms) of the station was expected to be in the order of 20%. However, in dry hydrological years or with major outages at other thermal power stations, the station was expected to be run extensively at higher load factors.

The refurbishment was carried out over the period 1983-86. A major feature of the refurbishment project was the retrofitting of electrostatic precipitators and associated flyash handling plant on the boiler gas outlets to reduce particulate emissions. In addition, boiler pressure parts were refurbished, controls and instrumentation were upgraded, and four of the steam turbines were refurbished and the condensers retubed. The refurbishment project was to cost around $30 million, to essentially provide a reliable and environmentally acceptable capacity of 180 MW (gross). That equated to a specific capital cost of around $170/kW, which was relatively low cost capacity even in those days (1982 – 86).

Toward the end of the refurbishment project the economic circumstances justifying the project changed and the work ceased, leaving the major part of the work done but not commissioned. In addition no. 1 boiler was damaged in a boiler explosion during recommissioning in 1985 and was not repaired. Steam turbine no. 7 had previously been damaged and decommissioned in 1979 and had been used for spare parts.

Meremere Power Station was rarely called on to generate after refurbishment and generated power for the last time in December 1990 and was decommissioned in March 1991 and placed in long term storage. Negotiations to sell the plant to a waste-to-energy developer took place in 1996/97 but the sale did not proceed. The station was eventually demolished, except for the turbine hall building which has been retained for use as a recycling centre, and the site rehabilitated.

Had the station continued in operation for the intended 10 years post refurbishment, to 1996, it would have been 38 years old. Neither the original design life nor the operating hours of the boilers and steam turbine generators are known.

3.3.2 Marsden A Power Station

Marsden A Power Station was the outcome of power planning that took place in the late 1950's and early 1960's. Construction of the 2 x 120 MW residual oil fuelled, subcritical, Rankine cycle, thermal power station, commenced in 1965 and the station was accepted by the New Zealand Electricity Department in June 1967.

The site at Marsden was originally selected because of its proximity to the nearby oil refinery. Marsden A was designed to burn a heavy residual oil which was a by-product of the refinery - it was New Zealand's first major oil fuelled power station. Provision was made for addition to its capacity in future years if required. The Marsden B facility was subsequently begun in 1975 and virtually completed in 1979. However, the sudden unexpected and rapid rise in the price of oil in the 1970's, and a less than forecast demand for power, led to the mothballing Marsden B before it was completed in 1979.

The annual operating hours and capacity factors for Marsden A are not known, however it is estimated that it may have operated with capacity factors of around 50% for the first decade of its life (1968 – 1978). The same circumstances that resulted in the mothballing of Marsden B would be expected to have also impacted on the operation of Marsden A. It is estimated that generation levels (and annual capacity factors) reduced after 1978 and on through the 1980s, particularly after Huntly Power Station was commissioned in 1982 – 1985. By 1990 it was recorded that:

"*Electricity generation at Marsden Power Station using oil fuel, costs significantly more than at Huntly Power Station using gas fuel. While there is sufficient lower cost generation from elsewhere in New Zealand, Marsden Power Station is not used for long-term generation of electricity. It is presently cheaper to transmit bulk electricity to Northland from south of Auckland, despite losses in the transmission process.*

Marsden A may appear to the casual observer to be unused, but it fulfils a valuable role in the electricity generation system. It is used for "hydro firming" and "voltage support" which requires the station to be constantly available.

The "hydro firming" role means that the station is used for generation at times of low water inflows into the hydro lakes. Three quarters of the country's generation is from hydro plant, so it is important that water is optimised for best use. To do this Marsden A must be available and ready to generate for up to four weeks continuous operation in a dry year.

The "voltage support" role means that the station's generators are used to maintain the voltage in the region north of Auckland at an acceptable level. This voltage support reduces the risk of voltage fluctuations that cause lights to dim and other inconvenience to consumers.

Electricorp has undertaken a review of all its thermal plant to confirm the optimal utilisation and availability of its generation capacity. Following this review the turbine one of the generating units at Marsden A has been placed in storage while the other unit is maintained for active use in a hydro firming role.

The unit currently in use also performs a critical standby duty. It ensures security of supply through being able to be brought into service in the case of other power station breakdowns. The generator of the second (stored) unit is used in the voltage support role.

In the mid to late 1990's predicted increases in electricity demand, or the need for additional hydro firming capacity, means this second unit will be brought back into service for generation before any new power stations are built. This would provide *a significant capital cost advantage over the construction of an equivalent new power station*."[20]

The 'voltage support' role noted above was achieved by using the generator as a synchronous condenser. This done by disconnecting the generator from its steam turbine, and by connecting an unused boiler feed-pump motor to the generator to provide for it to be run up to speed (3000 rpm) and synchronised to the electricity grid. This meant that the main plant items in a thermal power plant, the boiler and steam turbine, did not have to be "constantly available" as suggested above.

Some time in the 1990s, with the prospect of any further generation diminished, it was decided to close the Marsden A plant. In 1997 the non functioning parts of Marsden A were demolished, including the felling of both the Marsden A and Marsden B, 120m high reinforced concrete chimneys.

In October 2005, Mighty River Power, the current owner of the Marsden power plants, announced that it had "recommissioned a machine at the Marsden A Power Station to help improve electricity supply security in the Northland and Auckland regions." By "machine" it is understood to refer to the above noted generator that was set up as a synchronous condenser, as the Marsden A boilers and steam turbines were demolished in 1997. Only the turbine hall and control room building remains.

Marsden A was therefore around 30 years old when it was finally demolished, although it had probably ceased generation up to 10 years earlier. It is estimated that its life in operating hours was much 'younger' than its years, owing to the hydro support role over much of its life.

3.3.3 Conclusions

The design life and operating hours of Meremere and Marsden A power stations are not known. However, it is clear from the above accounts that these power plants were not shut down or decommissioned because their design life had expired, or because they were "worn out".

Their generation was reduced, and eventually ceased, because of economic reasons. These reasons were largely, it is suggested, relating to fuel costs and plant efficiency. It simply became uneconomic to procure the appropriate fuel, and convert it to electricity.

If there had been an adequate gas supply pipeline capacity to Marsden, or if the technology of the Marsden plants had made for practicable, low cost conversion to coal-firing, it is likely that Marsden A at least would have been converted to fire natural gas or coal.

Plant efficiency is not unrelated to age or, more precisely, to when the plant was in effect 'conceived'. Power plant unit sizes and efficiencies have steadily increased over time, and unit size itself has efficiency implications, as well as 'economies of scale'. Even with the relatively few thermal (boiler and steam turbine) power plants built in New Zealand, there has been a clear increase in the unit size and efficiencies of the New Zealand thermal plants.

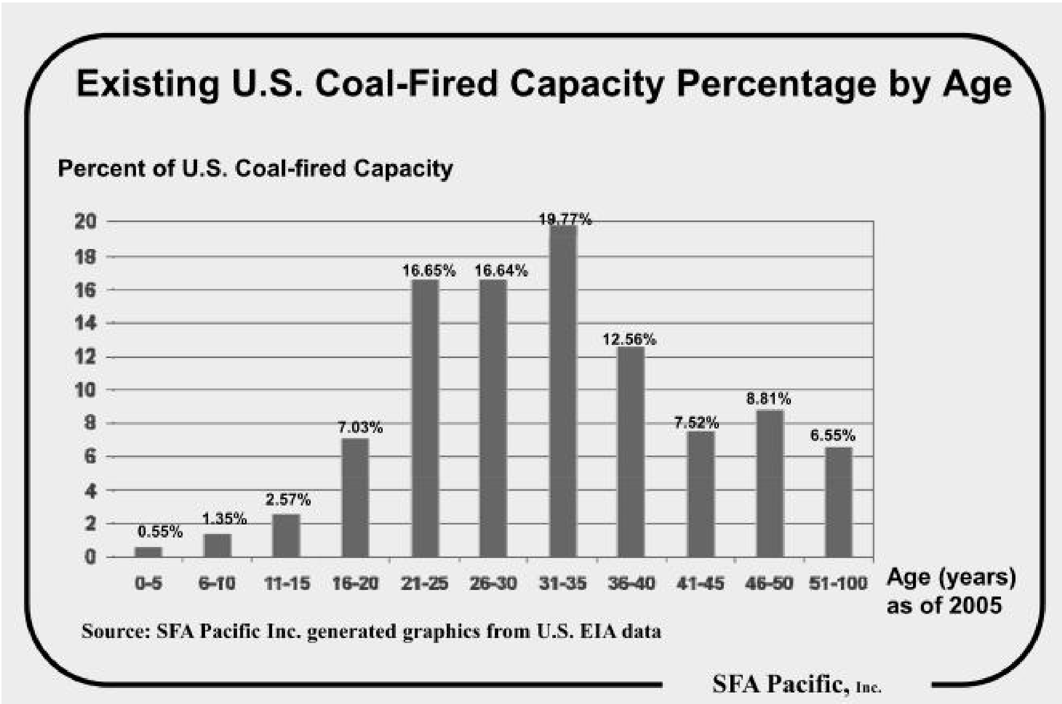
[20] Electricity Corporation of New Zealand Limited, Electricorp Production, Marsden B Power Station Investigations, Information Bulletin, November 1990

3.4 World trends of the life of coal and gas power stations

3.4.1 USA

Approximately 50% of the existing USA coal fuelled power plant fleet is greater than 30 years old, as shown in the following Figure 3-2.

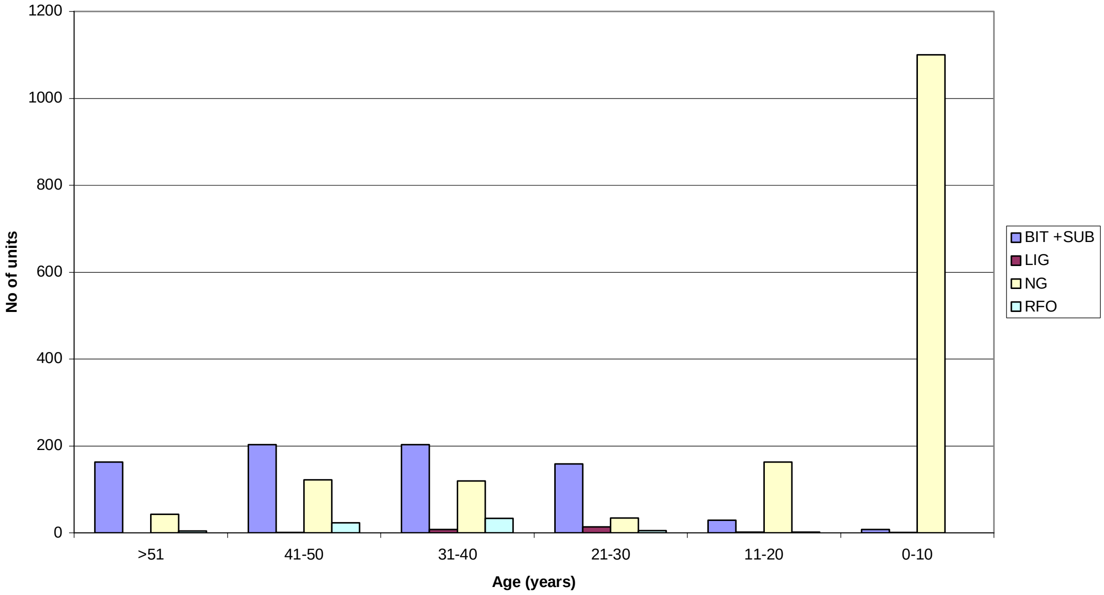
Figure 3-2 US coal-fuelled power plant age



As well as maintaining old power plants in operation, new gas-fuelled power plants are built to produce the electricity required. This is represented in the following Figure 3-3, showing the number and age of existing generating units (in operation (OP) or stand-by (SB)) over 100 MW in the United States in 2007 (source Energy Information Administration website[21]).

[21] Database Annual Electric Generator Report (http://www.eia.doe.gov/cneaf/electricity/page/eia860.html)

Figure 3-3 Age of existing generating units in USA in 2007 (OP + SB)



Key:

BIT = Bituminous

SUB = Sub-bituminous

LIG = Lignite

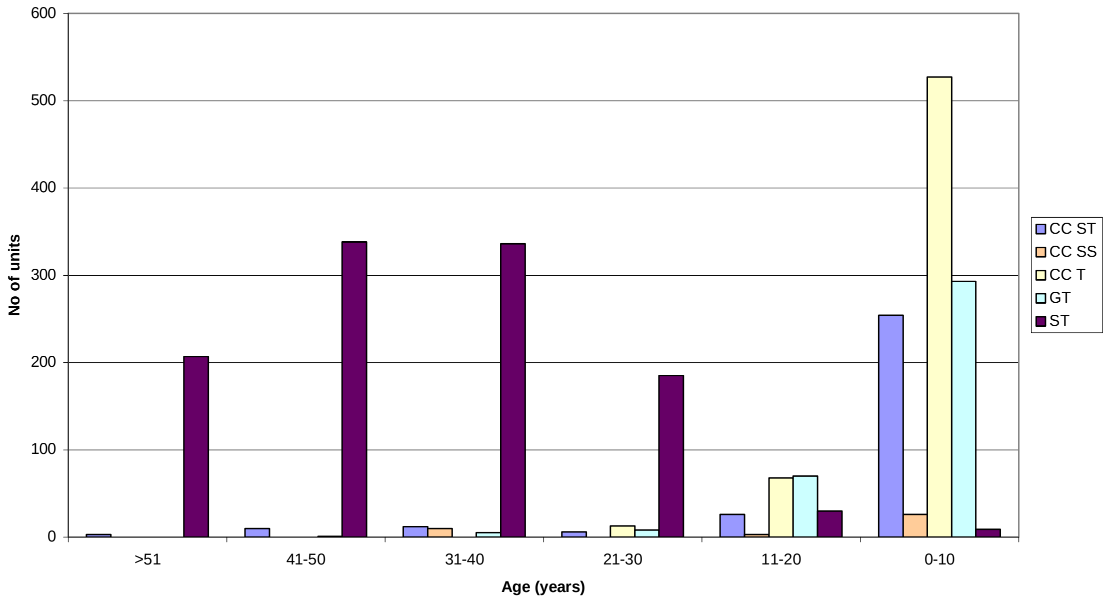
NG = Natural gas

RFO = Residual fuel oil

The trends observed in power plant construction (i.e. the decline of coal-fuelled plant and rise of gas-fuelled plants) can be compared to the evolution of the technology starting from development of Rankine cycle steam turbine based plants to combined cycle gas turbine plants.

Figure 3-4 separates combined cycle plants in three generating categories: steam turbine (CC ST), gas turbine (CC T) and single shaft (CC SS).

Figure 3-4 Age of existing generating units by technology in USA in 2007



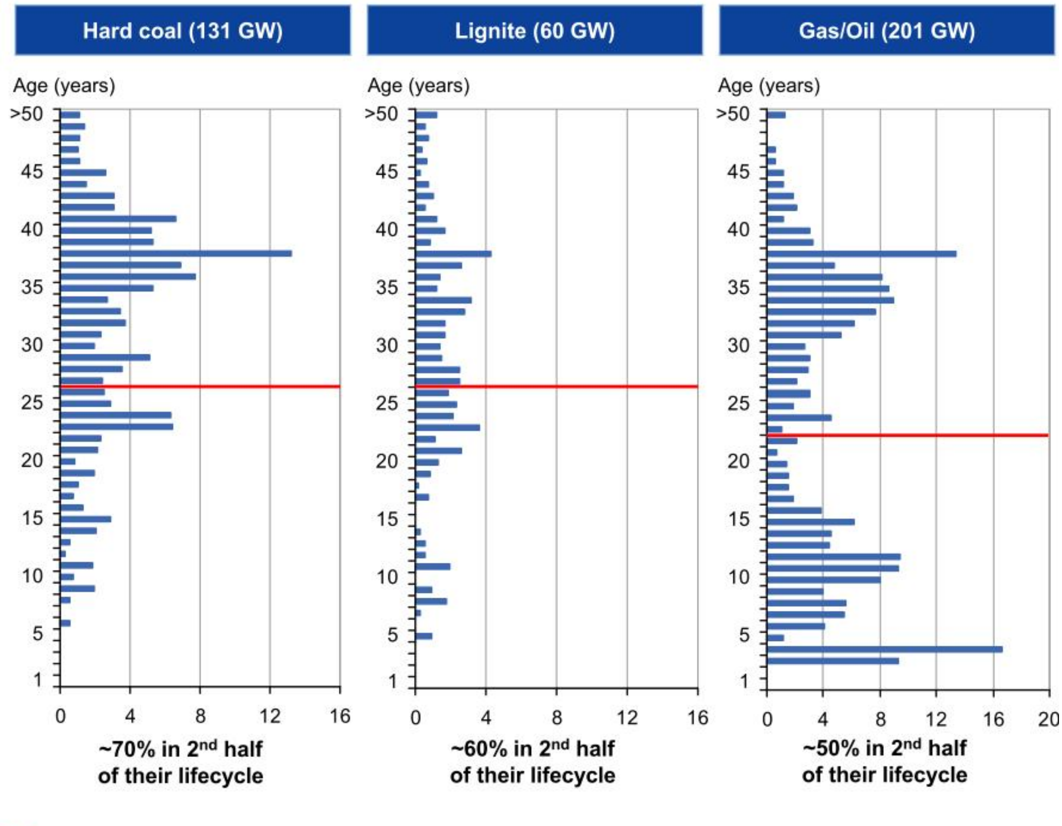
The trend in the age of steam plants (ST) above is a similar to that of the coal-fuelled plants in the previous figure. The recent construction of cleaner gas-fuelled plants is directly linked to the discovery and development of natural gas fields, and the associated development of gas-fuelled open and combined cycle plant gas turbine based power generation plant.

3.4.2 Europe

European power plants are also maintained well beyond the original design life as it is shown on the following Figure 3-5. (Source RWE[22])

[22] http://rwecom.online-report.eu/factbook/en/marketdata/electricity/generation/agestructure.html

Figure 3-5 Age structure of power plants in Europe in 2007



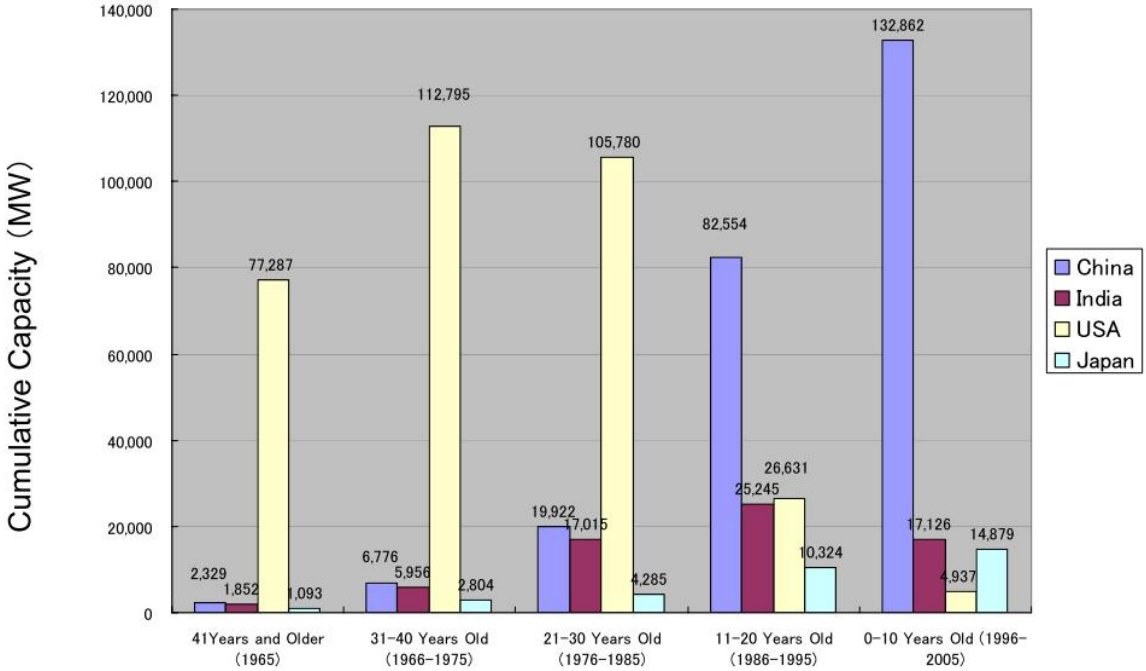
Sources: BCG, RWE.

The trend in age of coal-fuelled plants in Europe is similar to that in the USA. However, compared to the USA, where the gas-fuelled power plants are relatively young, the European gas-fuelled plants are on average older (gas/oil figure). The difference is possibly owing to the inclusion of the oil-fuelled plants which are older in the capacities reported.

3.4.3 Other

Power plants in the developing countries of China and India are more recent compared to the ones in the USA, and most of them have not yet reached their nominal design life. This is illustrated by the following Figure 3-6 which compares the age of existing coal-fuelled power plants in China, USA, India and Japan in 2007.

Figure 3-6 Age of power plants compared between countries



Sources: **Pradeep J. Tharakan, USAID-ECO-Asia Clean Development and Climate Program,** ASEAN Energy Business Forum (AEBF) 22nd -24th Aug.,2007 and Coal Note 2005/2006

3.5 Probability distributions

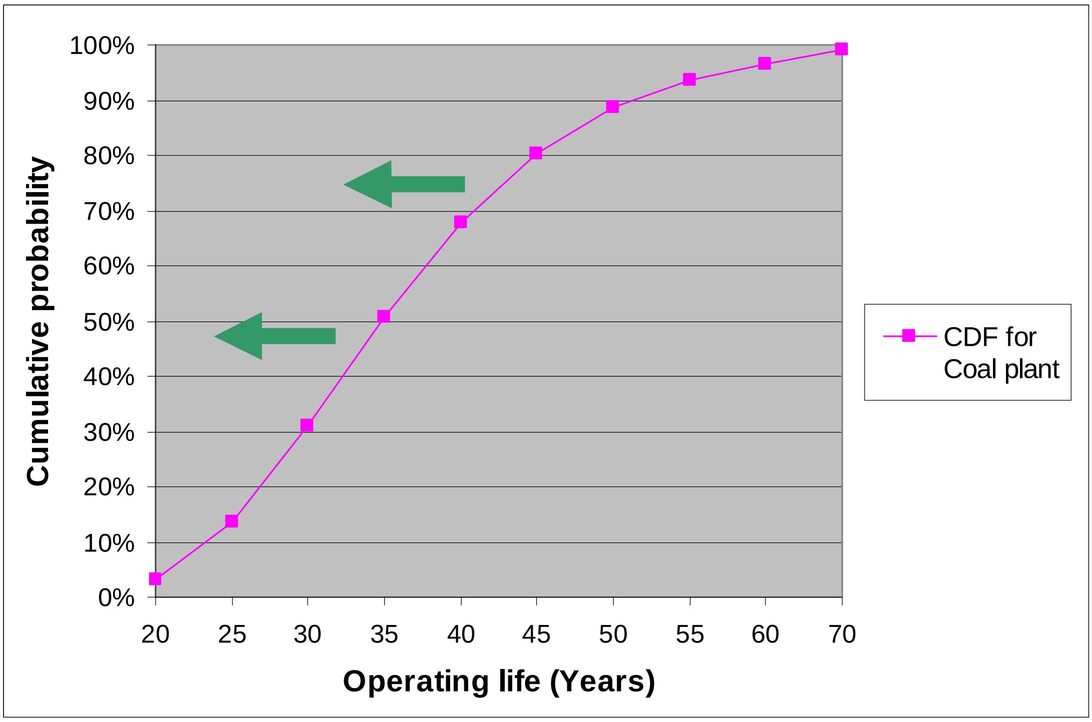
3.5.1 Lognormal distribution

The expected operating life of thermal plant is best approximated by a log-normal distribution, with very few plant being decommissioned before the end of the design life, and the majority of plant being decommissioned around the mean with progressively less plant existing for the older age brackets. The shape of the log-normal probability density function is supported by generators retaining older more inefficient plant for reserve and peaking roles, leaving the younger more efficient plant to be used for baseload operations.

3.5.2 Total operating life

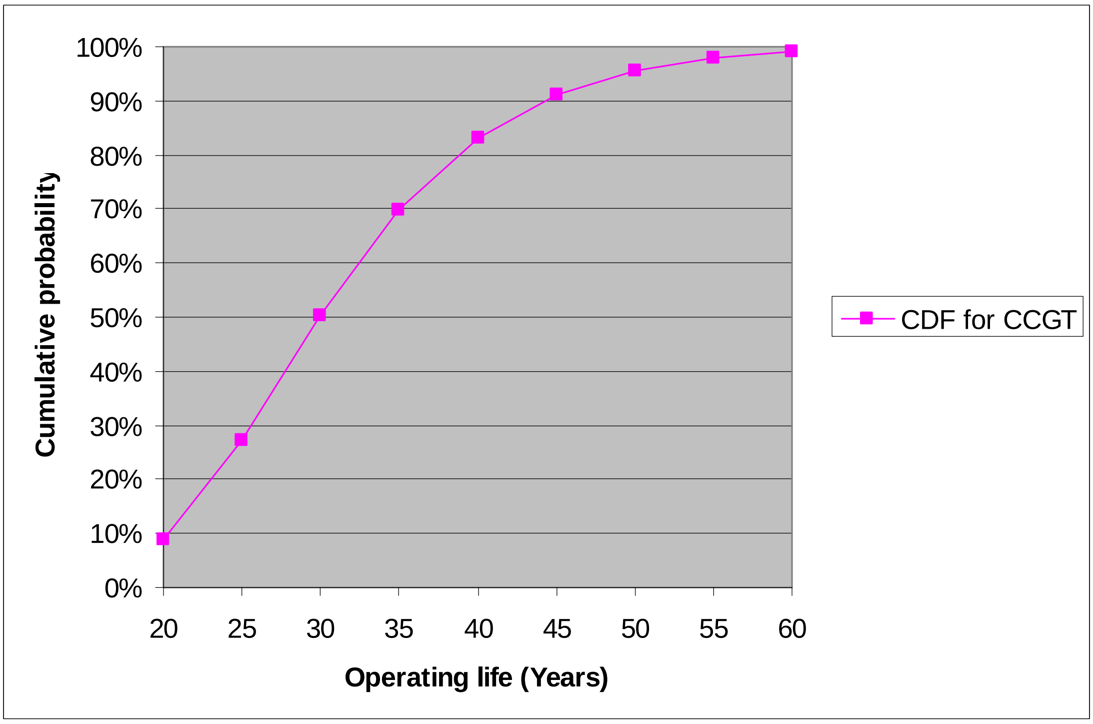
An estimate of the mean and standard deviation for the distribution can be made based on the available data and industry experience. Whilst sufficient data does not exist to create very statistically significant distributions, the combination of observed available data and engineering experience provides a reasonable basis for estimation. The mean operating life of coal plant is estimated at 35 years and CCGT plant at 30 years, the geometric mean of the log-normal distribution for coal plant is estimated at 3.55, and gas plant at 3.4. The geometric standard deviation for both plant types is estimated at 0.3. This provides the following cumulative density functions.

Figure 3-7 Cumulative distribution function for operating life of coal plant



The green arrows in Figure 3-7 represent the likely movement of the curve in response to the introduction of CO_2 emissions charging. Older plant with higher CO_2 emissions will be retired earlier as the costs associated with retrofitting emissions reducing technologies and actual CO_2 emissions costs reduce plant economics in relation to more efficient competing forms of cleaner generation.

Figure 3-8 Cumulative distribution function for operating life of CCGT plant



3.5.3 Effects of refurbishment

In the data reviewed, there was insufficient explanation on whether older plant which had exceeded original design life had undergone major life-extension refurbishment.

Due to the unique nature of each plant it is difficult to define what should be considered a refurbishment to extend life and what should be considered routine maintenance designed to maintain future plant reliability and availability. For example, the nature of maintenance programmes for CCGT plant indicates that life extension refurbishment can occur during scheduled ‘C’ level (50,000 hour interval) inspections, as part of the typical maintenance routine.

Without detailed information, it is therefore difficult to isolate observed operating lives for plant with and without major life-extension refurbishment.

3.6 Conclusions

As observed some coal fuelled steam and natural gas turbines are 40-50 years old and still in operation 20 years beyond the original nominal calendar design life. Whether thermal plants are refurbished, placed on standby or decommissioned before or at their design life remains primarily an economic decision for the owner. The economics of a unit are a function of market competitiveness, relating to potential net revenues versus the net costs which costs will include fuel, maintenance and capital costs. This decision is often difficult to make and the outcome is often based on reasons which are not always transparent to uninformed outside observation.

Recent observed plant retirement decisions in US and Europe have generally been made to replace still operable but older less efficient plant which require significant capital expenditure for emissions related upgrades required for regulatory compliance with newer more efficient (heat rate <7000 kJ/kWh) and lower emissions units.

4 Maintenance and refurbishment costs

4.1 Introduction

4.1.1 Electricity Commission brief

"*As decisions to decommission existing power plant by generating companies are likely to be made when lumpy major maintenance and refurbishment costs are faced, obtaining a better understanding of these for particular generating technologies will enable the Commission to model these with the Commissions expectations of future revenues from market processes*."

4.1.2 PB approach

PB has reviewed major maintenance practices for large thermal plant, for both gas turbines and coal fuelled steam plant. This includes recommended intervals based on equivalent operating hours and asset age.

PB has also provided an indication of the costs involved with major plant overhauls, how costs vary based on the size of the plant and how the plant has been operated and maintained.

4.2 General principles

OCGT and CCGT plant are typically constructed using a design life of around 25 to 30 years. The hot gas path components will need repair and replacing according to the OEM maintenance program several times during this plant design life calendar period.

If operated in a baseload regime most hot gas path components will reach the end of their design life of for example 100,000 EOH after 10 to 12 years. Because this is before the end of the power station design life, hot gas path component replacements are scheduled into the routine maintenance programme.

4.2.1 Operating hours versus Equivalent Operating Hours (EOH)

EOH is determined from baseload operating hours, the start/stop cycles and other factors such as turbine trips with corresponding weighting factors. One hour of baseload operation will be equivalent to one EOH, and one start may be given a loading factor of 10 hence accumulating 10 EOH.

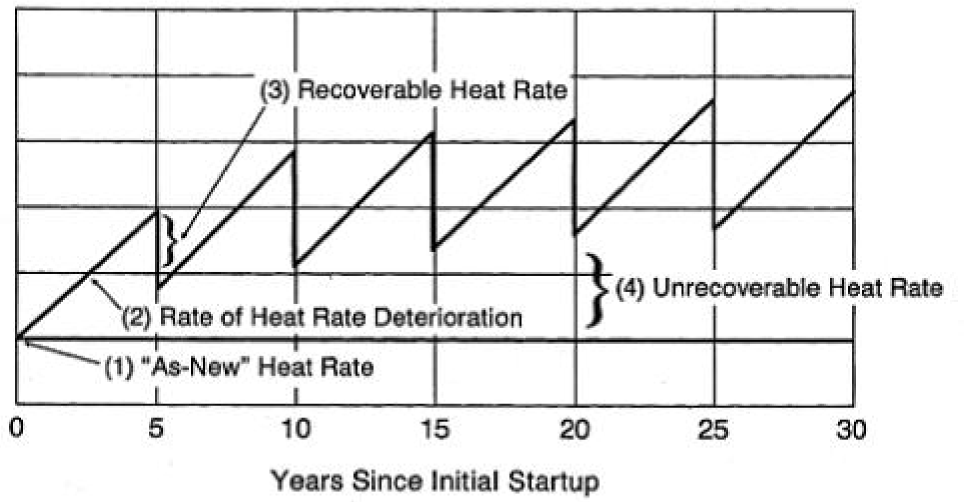
4.2.2 Plant deterioration

From the time a power station is put into service the deterioration process commences, resulting in a loss of efficiency, loss of availability, or a combination of both. This deterioration can be categorized as controllable or non-controllable. Controllable losses are generally owing to poor operation and maintenance practices. Non-controllable losses are due to environmental conditions (i.e. cooling water temperature, etc), dispatching requirements (i.e. customer demand) and normal deterioration.

Deterioration occurs as a result of use, and if left unchecked it can become substantial. Therefore, some amount of deterioration, normal deterioration, will always be present and non-controllable. Most of the normal deterioration can be recovered with regularly scheduled maintenance, the frequency of which determines the average deterioration based on the resulting saw-tooth heat rate curve shown in Figure 4-1. However, there is a gradual increase in the unrecoverable portion of the heat rate deterioration as a unit ages requiring component replacement rather than a refurbishment to eliminate.

Poor maintenance practices regarding the timing of the intervals, and the extent of refurbishment, may also result in excessive deterioration. However, this is controllable.

Figure 4-1 Change in heat rate over time[23]



Poor operation is also a controllable loss. It includes operating off-design (i.e. temperatures too low, or too high), running redundant equipment, particularly at part load, excessive start-ups owing to poor reliability, unit controls not properly tuned, and off-role operation.

Dispatch requirements determine the generation level of the unit and are not controllable. Since heat rate increases with decreasing load, this loss can be substantial; 5 -10% heat rate deterioration at half load.

Excessive deterioration and poor operating and maintenance (O&M) practices are recoverable through routine refurbishment and correction of poor O&M practices.

[23] General Electric GER – 3696D, Upgradable Opportunities for Steam Turbines, 1996.

4.2.3 Refurbishment or replacement

Beyond refurbishment, replacement of components in kind is the next step. This resets normal deterioration loss to 'as-new' values for the particular component and addresses maintenance reliability problems that can impact heat rate.

4.2.4 Upgrade

Replacement opens up the possibility of upgrade. Why not replace a part that may be 20 to 60 years old with today's technology and end up better than the original design? Turbine upgrades are prime examples. Controls, condensers and air heaters are other popular upgrades.

Table 4.1 quantifies typical turbine upgrades and identifies the gains available from recovery (in-kind replacement) and that owing to the improved design.

Table 4.1 Efficiency gains for steam turbines[24]

	Heat Rate Improvement - %	Output Increase - %
HP Section		
Advanced Design	0.40 to 0.60	0.70 to 1.00
Recovery of Aging	0.25 to 0.40	0.40 to 0.70
HP Section Total	0.65 to 1.00	1.10 to 1.70
IP Section		
Advanced Design	0.30 to 0.40	0.30 to 0.40
Recovery of Aging	0.10 to 0.20	0.10 to 0.20
IP Section Total	0.40 to 0.60	0.40 to 0.60
LP Section Without Last Stage		
Advanced Design	0.45 to 0.55	0.45 to 0.55
Recovery of Aging	0.10 to 0.20	0.10 to 0.20
LP Section Total	0.55 to 0.75	0.55 to 0.75
Last Stage		
Advanced Design	0.70 to 1.30	0.70 to 1.30
Recovery of Aging	0.05 to 0.15	0.05 to 0.15
Last Stage Total	0.75 to 1.45	0.75 to 1.45
Longer Last Stage Bucket	1.00 to 1.60	1.00 to 1.60
Total for Advanced Design	2.85 to 4.45	3.15 to 4.85
Total Recovery of Aging	0.50 to 0.95	0.65 to 1.25
Potential Improvement	3.35 to 5.40	3.80 to 6.10

4.2.5 Efficiency

Within the boundaries of current technical capability, the efficiency of a new power plant is largely a function of economic choices made at the time leading up to placement plant orders. The technology is well understood in order to produce a highly efficient plant. In order to produce higher efficiencies, higher pressure and temperatures are required. This increases the cost of the plant as special alloy materials are needed. Technology advances (typically incorporated during major refurbishments) could assist by lowering the cost of these special materials through discovery and better manufacturing process.

There are a few changes that can be made to make an existing unit more efficient without injection of large amounts of capital. However these changes typically will

[24] Supra note 23.

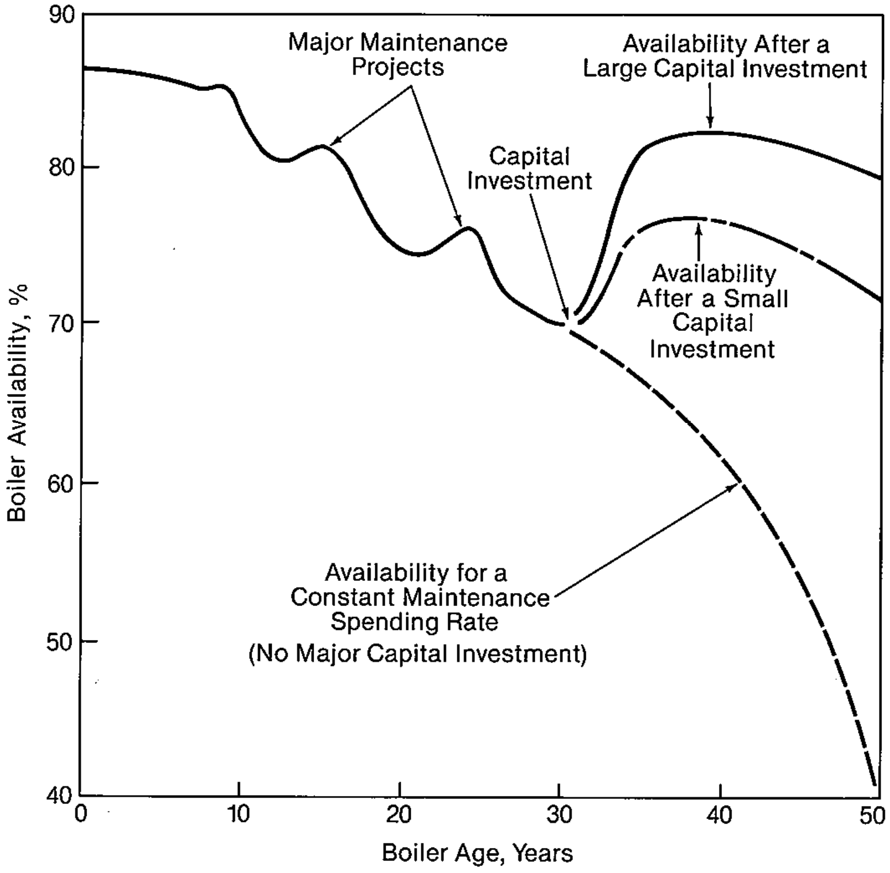
only result in a few percentage point improvements to efficiency, e.g. 35.0% to 35.2%.

4.2.6 Major maintenance

As can be seen from Figure 4-1, continuation of annual maintenance will result in a progressive deterioration of plant over its lifetime. This deterioration can be reduced, and even reversed by major maintenance at times during the plant life, and generally the level of capital injection for such major maintenance (or major refurbishment) will dictate the effectiveness of such measures in improving the plant's performance. This is shown in the following Figure 4-2, a typical diagram for a boiler.

The capital injection for any of these maintenance projects or mid-life refurbishments will be specific to the power station and even the components being considered, and will depend on a large number of factors relating to the operation (past and future) and state of the equipment at the time.

Figure 4-2 Typical availability curve for a large, high pressure power boiler with a life extension capital expenditures[25]



Availability curves for other major plant components, and the power plant as a whole, will follow the above-indicated trends.

[25] Babcock & Wilcox, "Steam – Its generation and use", 40th edition, page 46-2, 1992

4.2.7 Redesign

Advancement in design opens up the possibility of modifying the original design of a unit. This can be as "simple" as resizing the backend of the turbine to increase flow capability or reduce losses owing to being undersized in the original economic analysis (low fuel prices), or as complicated as totally replacing major pieces of equipment and modifying the overall cycle. In some cases, such as turbine nozzles, the replacements can be designed to have a lower rate of deterioration.

In the extreme, this type of upgrade can be a repowering where the boiler is replaced by combustion turbines, a new boiler or converted (CFB). Significant efficiency and fuel changes are possible.

4.2.8 Conclusions

Deterioration can be addressed as follows:

- Refurbishment
- Replacement in kind
- Replacement with advanced design
- Modify original design
- Repowering
- Retirement with replacement by new construction

Complete replacement of power stations nearing their original design life with similar-sized units seldom tends to enjoy a compelling economic argument. Instead, there is usually a stronger economic justification to improve the efficiency, availability and reliability through cost-effective upgrading, refurbishment and operations and maintenance improvements. Most often the revenues available at current market prices are insufficient to cover the capital expenditures required for a new plant despite the greater performance benefits available from entirely new units. New replacement units are usually justified once the extended life has been expended, or by the need for additional generating capacity to supply increasing demand.

One major advantage from plant performance improvements is the reduced relative emissions from the power station.

Mid-life refurbishment typically includes major replacement of control and instrumentation systems, both for the data storage and control systems and for measuring elements, e.g. pressure and temperature sensors. Such new control and instrumentation equipment generally results from the obsolescence of much of hardware and the consequent lack of spares availability.

Major refurbishment may also be required to comply with changed environmental guidelines and standards, such as may be required to incorporate options to reduce NOx, SOx, particulates or CO_2 emissions. However, the scope of such work will be dependent on the existing technology employed in the power station and the regulatory and economic circumstances which would incentivise changes to be implemented. Consequently, such refurbishment is considered on a case by case basis.

4.3 Refurbishment costs and frequency

4.3.1 General

Costs of mid-life and other major maintenance and refurbishments projects are dependent upon the scope of the work and the desired life extension to be obtained. The scope of work will also depend on how the plant has been operated. For example, base-load operation of Huntly power station on natural gas fuel is generally less demanding on equipment (particularly boiler heating surfaces) than operation on coal fuel.

Major refurbishment was recently carried out on Maritsa East power station (4 x 210 MW coal-fuelled units) in Bulgaria. Refurbishment included both increasing output (unit outputs from 210 MW to 227 MW) and incorporation of flue gas desulphurisation (FGD) plant. Total costs were about US$260 million per 210 MW unit (US$310 per kW); with about 25% of this being for FGD plant. This Maritsa East refurbishment, including addition of the FGD plant required work to ensure operational compliance with European emission standards.

PB was also involved in the extensive refurbishment of Playford B power station in South Australia. The total cost of this work was about $A150 million for the four 60 MW units, equating to about NZ$800 per kW.

4.3.2 Steam power plant

A total mid-life refurbishment cost of up to $100 million for each 250 MW unit (NZ$400 per kW) at Huntly power station could be expected, and such refurbishment would be expected to include the following items (not in any order of importance):

- Condenser re-design and re-tubing
- Boiler economiser tube and major component replacement
- Boiler air heater replacement
- LP turbine re-blading of last stages
- Hot reheat piping and header inspection and replacement
- HP steam piping and header inspection and replacement
- Boiler superheater tube replacement
- Boiler feed pump refurbishment
- Boiler insulation replacement.

This cost estimate is based on recent cost commitments by CS Energy in Queensland for a mid-life refurbishment of Callide B power station. This station is 20 years old, and the scope of refurbishment was expected to add 20 years to the economic operating life of the station.

PB expects that $100 million per unit for Huntly units 1-4 refurbishment would provide a similar extension to station life, noting that Huntly 250 MW units are at least 24 years old.

For the smaller (120 MW) New Plymouth power station units and noting that operation is only with natural gas, mid-life refurbishment costs could be of the order of $50 million per unit.

4.3.3 Combined cycle gas turbine (CCGT)

A typical CCGT power plant lifetime is 20 to 25 years. The major plant items should achieve this life with the correct maintenance and provided the operating regime is as originally envisaged.

It sometimes happens that plant designed to be base loaded reverts to two-shifting and then peaking as it descends the merit order. In this case the HRSG may need to be refurbished but the ST and GT should not require anything beyond normal regular maintenance.

The control systems are unlikely to achieve the design life because of obsolescence as noted previously, but replacement control systems are not expected to incur large capital expenditure.

If the plant life is to be extended beyond 25 years, say up to 40 years, then extensive refurbishment will be required. Such refurbishment could cost around 50% to 60% of a new plant.

Assuming that the plant is continuously operated on a base-load basis, within the original equipment manufacturer (OEM) guidelines, and trips and starts are within design limits, the following periodic maintenance tasks are expected to be required:

Gas turbines

- Combustor inspection every year
- Hot gas path inspection every 2 years
- Major inspection including repair/replacement every 5 years

Generators

- General inspection every year
- Major inspection including repair/replacement every 5 years

Steam turbines

- Boroscope examination every 2 years
- Major inspection including repair/replacement every 5 years

4.3.4 Availability of information

Documentation in the public arena related to power station refurbishment, particularly for Australian and even more so for New Zealand, lacks any detail about the scope of work carried out. For example, CS Energy annual reports merely state that A$200 million is allocated for mid-life refurbishment of Callide B power station over a period of up to five years.

5 Projected decommissioning of NZ thermal plant

5.1 Introduction

5.1.1 EC Brief

"Assuming no refurbishments, a projection of the decommissioning date of each of the New Zealand thermal power plants. It may be appropriate to provide more than one set of projections. Another set of projections should be provided for each of the plant if a refurbishment is assumed. Technical details about the refurbishment, cost estimate and estimate on the extension of the operating life of the plant in years will be expected. The assumptions behind each projection and costs should be clearly explained."

5.1.2 PB approach

The estimated decommissioning date for each of the NZ thermal plant included in the scope of the study has been based on a set of assumptions around the original design life and operating regime of the plant. Using the findings from previous sections of this report, PB has discussed the key factors in estimating the remaining life of the assets.

In addition, PB has discussed when major life extension maintenance decisions may occur, including which items of the plant may require refurbishment, alternative options available to the asset owner, the level of costs involved and how major maintenance impacts on extending asset life.

5.1.3 Limitations

Information which directly impacts an owner's decision to retire plant such as expected revenues, costs and profit expectations is confidential, proprietary or unknown. This section of the report has not provided comment on whether an asset remains financially viable or not at some point in the future, but rather has provided a view about when an asset may be decommissioned based on a set of engineering assumptions on plant lives and opportunities for life extension.

The refurbishment costs included in the projections are based on the estimates of original plant capital costs which used NZ$1 = US$0.60 cents. The capital costs are materially affected by movements in the exchange rates, primarily the USD which is used for the offshore costing of thermal plant. Approximately 75% of the total capital cost of thermal plant will be exposed to exchange rate movements.

5.2 Huntly Power Station - Units 1 to 4

5.2.1 Original design life

Subcritical, Rankine cycle, thermal generation units of the size installed at Huntly (250 MW) had an original design life of 25 years, and was commissioned in 1982 - 1985. As discussed in Section 2, the design life was based on an operating hours expectation of 200,000 hours[26].

Plant of this type has been observed to remain in operation well beyond the original design life, with a number of plants still in operation 50 years after commissioning. It should be noted that the role in which they are operating may be different from that originally envisaged for the plant, and that the actual operating hours of these older plants may be less than the original design life expressed in hours.

5.2.2 Projected major maintenance timings and costs

PB has assumed that units 1-4 will continue using predominantly coal fuel, which carries a higher maintenance cost compared to using gas fuel, with any available gas used in higher efficiency gas turbine plant such as E3p (unit 5).

Major unit overhauls of the plant will occur approximately every five to eight years and have the potential to take the plant off-line for a number of months. The cost of the major unit overhaul excluding lost revenue will depend primarily on the extent of work required.

The last major unit overhaul at Huntly occurred in 2008, which would suggest 2013 - 2016 for the next major maintenance of that unit.

Mid-life refurbishments could be planned for 2015 to 2020, to extend the life of the plant out further than 2020, and would be required to improve efficiency especially if units 1-4 were required to operate in a baseload or intermediate to baseload regime.

PB estimates that a mid-life refurbishment of units 1-4 would cost between 20% and 40% of the original plant capital cost, equivalent to $400 - $800/kW, or $400 to $800 million for all four units (1,000 MW). The ultimate cost would depend on factors such as scope of works, exchange rates and commodity prices at the time of expenditure. This level of refurbishment can be expected to provide an additional 15 to 20 years of useful operating life.

Cost would depend primarily on the level of technical operating life extension required. PB estimates that whilst 20% of original plant capital cost may be required to gain an additional 15 years of technical operating life, a further 20% would be required to achieve an additional 5 years, a total of 20 years, due to the

[26] 200,000 hours over 25 years implies a lifetime load factor of 91%.

nature of works required e.g. requiring replacement of equipment such as boiler feed pumps rather than refurbishment.

5.2.3 Projected decommissioning date

Given that the main boiler plant is now approximately 25 years old, and has consumed approximately 75% of the design operating hours, a prediction of a further 10 years of reliable operation to 2020 is reasonable based on the assumption that regular scheduled maintenance is performed without the need for mid-life refurbishment. This is supported by the fact that gas was the predominant fuel up to 2002, resulting in less wear and tear on the main coal handling plant.

Extension of the life of the units beyond 2020 will be likely to require a significant refurbishment including the C&I upgrades over the next 10 years. Given the nature of the plant and observed lives of similar plant around the globe, as long as the economics allow refurbishments to be executed, there should be no technical reason why the plant could not continue to operate for another 25 years, doubling the original design life to 50 years, with a projected decommissioning date of 2035.

5.3 Huntly Power Station - Unit 5 CCGT

5.3.1 Original design life

Large combined cycle gas turbine plants are typically designed and manufactured using a design life of between 25 and 30 years. Due to the nature of the plant and EOH penalties associated with start and stops, the plant is generally used in a baseload operation role. This is consistent with the actual operating hours for the plant since commissioning in 2007.

5.3.2 Projected major maintenance timings and costs

Controls and instrumentation upgrades will occur approximately every 15 years. Based on PB's experience with similar projects, these typically incur costs of around NZ$20-$30 million for plant of this type.

Routine major maintenance on CCGTs occur approximately every 25,000 equivalent operating hours (EOH) so for plant operating in a baseload role with load factors above 80%, these would typically occur every 3.5 - 4 years. Major maintenance programmes typically incur costs in the range of $25-$35 million depending on the scope of work.

Mid-life refurbishment of such equipment would be done to potentially re-instate original efficiency and extend the actual operating life of the plant. Associated Capex would be around $400 to $500 per kW ($154m - $193m), or around 40% to 50% of the original plant cost. This is likely to occur around two-thirds of the way through the original design life and extend the operating life by an amount equal to two-thirds of the original design life of the plant or an additional 20 years based on a design life of 30 years.

5.3.3 Projected decommissioning date

Ignoring the economics of fuel supply to the CCGT, PB would estimate that without mid-life refurbishment, plant of this nature should be able to operate beyond the original design life to at least 30 years of operation to 2037. Mid-life refurbishment of the unit would occur around 2027 and be likely to extend the potential operating life of the plant out to 2057.

5.4 Huntly Power Station - Unit 6 OCGT

5.4.1 Original design life

Open cycle gas turbine plants typically use an economic and design life of around 25 years for engineering design and manufacture specifications. Due to the nature of the plant and EOH penalties associated with start and stops, the plant is typically used for any role from peaking to baseload. P40 has been used as an intermediate role over the first five years of operation since commissioning in 2004.

5.4.2 Projected major maintenance timings and costs

Controls and instrumentation upgrades will occur approximately every 15 years. Based on PB's experience with similar projects, these typically incur costs of around NZ$5 million for plant of this type.

Routine major maintenance on OCGTs occur approximately every 25,000 equivalent operating hours (EOH) so for plant operating in an intermediate role with load factors around 40%, these would typically occur every 5 - 6 years depending on the number of start/stops. Major maintenance programmes incur costs in the range of $10-$15 million excluding missed revenue from lost generation.

Mid-life refurbishment of such equipment would be completed to restore original efficiency levels and extend the operating life of the plant. Associated Capex would be around $400 to $500 per kW ($20m - $25m), or around 40 to 50% of the original plant cost. This is likely to occur around two-thirds of the way through the original design life and extend the operating life by an amount equal to two-thirds of the original design life of the plant.

5.4.3 Projected decommissioning date

PB would estimate that without mid-life refurbishment plant of this nature should be able to operate to the original design life of 25 years of operation with regular maintenance. Given the plant was commissioned in 2004, mid-life refurbishment of the unit would occur around 2021 and be likely to extend the life of the plant out to 2046.

5.5 Taranaki CCGT

5.5.1 Original design life

Large combined cycle gas turbine plants are typically designed and manufactured using a design life of between 25 and 30 years. Due to the nature of the plant and EOH penalties associated with start and stops, the plant is generally used in a baseload operation role. This is consistent with the actual operating hours for the plant since commissioning in 1998. TCC has already been upgraded during a major overhaul in 2001 which provided some efficiency improvement and a capacity increase instead of extending operating life.

5.5.2 Projected major maintenance timings and costs

Controls and instrumentation upgrades will occur approximately every 15 years. Based on PB's experience with similar projects, these typically incur costs of around NZ$20-$30 million for plant of this type.

Routine major maintenance on CCGTs occur approximately every 25,000 equivalent operating hours (EOH) so for plant operating in a baseload role with load factors above 80%, these would typically occur every 3.5 - 4 years. TCC would have had three major maintenance inspections, possibly occurring in 2001, 2004 and 2008 judging by the outage impact during these operating years. Major maintenance programmes also known a 'C' inspections incur costs in the range of $25-$35 million.

A mid-life refurbishment of such equipment would be completed to improve efficiency and extend the operating life of the plant, possibly through replacement of existing plant with improved current technology. Associated Capex would be around $400 to $500 per kW ($154m - $193m), or around 40% to 50% of the original plant cost. This is likely to occur around two-thirds of the way through the original design life and extend the operating life by an amount equal to two-thirds of the original design life of the plant.

5.5.3 Projected decommissioning date

PB estimates that without mid-life refurbishment, plant of this nature should be able to operate beyond the original 25 year design life to at least 30 years of operation taking decommissioning to around 2028. Mid-life refurbishment of the unit would occur around 2018 and be likely to extend the life of the plant out to 2048.

5.6 Otahuhu B CCGT

5.6.1 Original design life

Large combined cycle gas turbine plants are typically designed and manufactured using a design life of between 25 and 30 years. Due to the nature of the plant and EOH penalties associated with start and stops, the plant is generally used in a baseload operation role. This is consistent with the actual operating hours for the plant since commissioning in December 1999.

5.6.2 Projected major maintenance timings and costs

Controls and instrumentation upgrades will occur approximately every 15 years. Based on PB's experience with similar projects, these typically incur costs of around NZ$20-$30 million for plant of this type.

Routine major maintenance on CCGTs occur approximately every 25,000 equivalent operating hours (EOH) so for plant operating in a baseload role with load factors above 80%, these would typically occur every 3.5 - 4 years. Major maintenance programmes incur costs in the range of $25-$35 million depending on the scope of work being performed.

Mid-life refurbishment of such equipment would be completed to restore unit efficiency and extend the operating life of the plant. Associated Capex would be around $400 to $500 per kW ($152m - $190m), or around 40 to 50% of the original plant cost. This is likely to occur around two-thirds of the way through the original design life and extend the operating life by an amount equal to two-thirds of the original design life of the plant or around 20 years.

5.6.3 Projected decommissioning date

PB would estimate that without mid-life refurbishment, plant of this nature, with regular maintenance, should be able to operate beyond the original design life to at least 30 years of operation and hence the projected decommissioning date would be 2029. If economic, a mid-life refurbishment of the unit would occur around 2019 and be likely to extend the operating life of the plant out to 2049.

5.7 New Plymouth Power Station

5.7.1 Projected decommissioning date

At this stage there is no future decommissioning date published by Contact Energy. The plant remains available as reserve capacity providing a security of supply role. This could continue to be provided until such time as the economics of maintaining the plant and providing the reserve capacity are not acceptable to Contact.

It is unlikely that the plant would be restored to a regular generating role given the availability and price of fuel, and more efficient plant in the generation portfolio.

5.8 Southdown cogeneration (122MW)

5.8.1 Original design life

Combined cycle gas turbine plants are typically designed and manufactured using a design life of 25 years. Due to the nature of the plant and EOH penalties associated with start and stops, the plant is generally used in a baseload operation role. This is consistent with the actual operating hours for the plant since commissioning in 1998.

5.8.2 Projected major maintenance timings and costs

Controls and instrumentation upgrades will occur approximately every 15 years. Based on PB's experience with similar projects, these typically incur costs of around NZ$15-$20 million for plant of this type.

Routine major maintenance on CCGTs occurs approximately every 25,000 equivalent operating hours (EOH) so for plant operating in a baseload role with load factors above 80%, these would typically occur every 3.5 - 4 years. Southdown would have had three major maintenance inspections based on the accumulated operating hours for the plant. Major maintenance programmes also known as 'C' inspections incur costs in the range of $20-$30 million for this size of plant.

A mid-life refurbishment of Southdown would be completed to improve efficiency and extend the operating life of the plant, possibly through replacement of existing plant with improved current technology. Associated Capex would be around $400 to $500 per kW ($50m - $62.5m), or around 40% to 50% of the original plant cost. This is likely to occur around two-thirds of the way through the original design life and extend the technical operating life by 20 years.

5.8.3 Projected decommissioning date

PB estimates that without mid-life refurbishment, plant of this nature should be able to operate beyond the original 25 year design life to at least 30 years of operation taking decommissioning to around 2028. Mid-life refurbishment of the unit would occur around 2018 and be likely to extend the life of the plant out to 2048.

5.9 Southdown E105

5.9.1 Original design life

Open cycle gas turbine plants are typically designed for an operating and economic life of around 25 years. Due to the nature of the plant and EOH penalties associated with start and stops, the size of plant is typically utilised for any role from peaking to baseload. Since commissioning in 2007, the unit has been used in a peaking role and to provide voltage support to the national grid.

5.9.2 Projected major maintenance timings and costs

Controls and instrumentation upgrades will occur approximately every 15 years. Based on PB's experience with similar projects, these typically incur costs of around NZ$5 million for plant of this type.

Routine major maintenance on OCGTs occur approximately every 25,000 equivalent operating hours (EOH) so for plant operating in a peaking role with load factors around 20% and frequent start/stops incurring an EOH penalty, these would typically occur every 5 - 6 years. Major maintenance programmes for this size OCGT incur costs in the range of $10-$15 million.

Mid-life refurbishment of such equipment would be completed to restore original efficiency levels and extend the operating life of the plant. Associated Capex would be around $400 to $500 per kW ($18m - $22.5m), or around 40% to 50% of the original plant cost. This would be likely to occur around two-thirds of the way through the original design life and extend the operating life by an amount equal to two-thirds of the design life of the plant.

5.9.3 Projected decommissioning date

PB would estimate that without mid-life refurbishment plant of this nature should be able to operate to the original design life of 25 years of operation with regular maintenance. Given the plant was commissioned in 2007, mid-life refurbishment of the unit would occur around 2024 and be likely to extend the life of the plant out to 2049.

5.10 Whirinaki Power Station

5.10.1 Original design life

OCGT plant such as the Pratt & Whitney FT8 Twin Pac gas turbine generators are typically designed and manufactured using an economic and design life of around 25 years. Due to the nature of the plant and EOH penalties associated with start and stops, the size of plant is typically utilised for any role from peaking to baseload. Since commissioning in 2004, the units have been used to provide reserve generation and hence have typically displayed very low annual load factors.

5.10.2 Projected major maintenance timings and costs

Controls and instrumentation upgrades will occur approximately every 15 years due to technological obsolescence. Based on PB's experience with similar projects, these typically incur costs of around NZ$5million for plant of this type.

Routine major maintenance on OCGTs occur approximately every 25,000 equivalent operating hours (EOH). For plant like Whirinaki which are unlikely to reach the intervals for major maintenance in less than 10 years, most OEM recommend major maintenance is carried out on a time basis independent of actual operating hours. Based PB experience an interval of 7 years would be appropriate for plant being run in this way to undergo a major overhaul. Major maintenance programmes for OCGTs of this size incur costs are in the range of $10-$15 million.

Mid-life refurbishment would typically only be completed in order to support a change in the operating regime such as a change of fuel type or move to higher load factors. Since operating hours are so low, efficiency gains would not be so relevant to plant being used as reserve capacity operating infrequently. Associated Capex for a mid-life upgrade would be dependant on the nature of the change, but would be in the order of around $400 to $500 per kW ($62m -

$77.5m), or around 40 to 50% of the original plant cost. This would be likely to occur around 60%-75% of the way through the original design life and extend the operating life by an amount equal to the original design life of the plant.

5.10.3 Projected decommissioning date

PB would estimate that without mid-life refurbishment plant of this nature should be able to operate to the original design life of 25 years of operation with regular maintenance. This suggests a decommissioning date of 2029.

Given the current configuration and operating regime of the plant, it is difficult to imagine a scenario where a mid-life refurbishment would be required.

5.11 Summary

Table 5.1 shows the estimated decommissioning dates for thermal plant in New Zealand with and without a major mid-life life refurbishment for the purposes of life extension.

Table 5.1 Projected decommissioning dates of NZ thermal plant

Plant	Commission - ing date	Design life *(Years)*	Projected decomm. date	Refurb. date	Refurb. Capex ($/kW)	Projected decomm. date with mid-life refurb.
Huntly PS - (Units 1 to 4)	1982 - 1985	25	2020	2020	864	2035
Huntly PS - CCGT	2007	25 to 30	2037	2027	492	2057
Huntly PS – OCGT	2004	25	2029	2021	400	2046
TCC	1998	25 to 30	2028	2018	480	2048
Ota B	1999	25 to 30	2029	2019	480	2049
New Plymouth	1974 - 1976	25	n/a	n/a	n/a	n/a
Southdown CCGT	1998	25	2028	2018	480	2048
Southdown E105	2007	25	2032	2024	368	2049
Whirinaki	2004	25	2029	n/a	n/a	n/a

6 Long run marginal costs of generation

6.1 Introduction

6.1.1 EC Brief

"Long run marginal cost of the plants over their life should be calculated for the two projections (with and without refurbishment) and this for each of the plants. A discussion around the results should be given to assess if the refurbishment is cost effective. This might include a comparison with renewable LRMC values. All assumptions around the LRMC calculation should be clearly specified."

6.1.2 PB Approach

A Microsoft Excel® model has been created to estimate the Long Run Marginal Costs (LRMC) of generation ($/MWh) for each of the thermal plants included in the scope of the study. These estimates necessitate assumptions including capital costs, heat rates, annual generation, asset life, fuel costs and operating costs. The modelling has been extended to include the commercial effects of mid-life refurbishments which involve significant capital expenditure and an extension to the original design life of plant.

6.1.3 Background

The LRMC of generation is defined as the price that is sufficient to cover all plant costs (in this context, including plant capital costs, carbon costs, fuel costs, operations and maintenance costs) over the life of a plant.

The LRMC of a particular generation plant is influenced by a number of key parameters, including:

- Fuel, its cost is probably the most significant long term factor
- Scale of project; this influences the capital cost, the technology choice and efficiency of the operation;
- Cost of capital has a significant impact on the cost of generation;
- Electricity generation technologies are developing at a fast pace. The last ten years has seen a major change in the economics, scale and efficiency of generation technologies; this technology development is expected to continue.
- Timing factors are important because LRMC will be determined by the most economic options of the day, some cost factors change in a non-linear fashion

with time (for example the price of gas, the price of metals, market prices of OEM offerings); and

- The plant's net capacity factor resulting from its intended role and market competitiveness strongly influences the unit cost of generation. A generation plant designed to operate infrequently to supply high market price peak demands may be economic to install despite higher unit generation costs.

The PB model uses a formula for LRMC calculation which calculates the electricity selling price which generates enough revenue to set the Net Present Value (NPV) of the costs of generation over the life of the plant to zero. In other words, the LRMC is the levelised unit cost of electricity generation or the price that is sufficient to cover all plant costs over the life of a plant.

6.1.4 LRMC model

An Excel spreadsheet was used to create the LRMC model. The model has been constructed on a real costs basis, removing the requirement to forecast or assume inflation rates.

The model has not considered debt/equity funding costs or capital/shareholder repayments, instead evaluating costs on a project basis. The model does not include taxation, depreciation, transmission costs, network losses or decommissioning costs.

Instead of retrospectively calculating actual LRMCs for NZ thermal plant based on actual costs and performance, the model estimates the LRMCs of the plant if they were built now and examines the effects on the LRMCs of a mid-life refurbishment. This provides the Commission with an understanding of the commercial impact of decisions to extend a plant's life.

The mid-life refurbishment of thermal plant typically achieves two main objectives, extension of operating life and efficiency improvement. The plant efficiencies, have been modelled as constant, increases in plant efficiency originating from routine maintenance or mid-life refurbishment have not been modelled. Instead the focus for the review is the effect of the life-extension of the mid-life refurbishment on the LRMC.

Increases in plant capacity and reductions in emissions are also objectives of major capital investment but not as common or as relevant to the objectives of this study. In addition, assuming no real increases in price factors such as fuel and O&M costs isolates and highlights the effects of mid-life refurbishments on the LRMC over the evaluation period.

6.2 Assumptions

The assumptions for the modelling have been split into generic assumptions which apply to all scenarios and assumptions specific to each plant. All assumptions have been created as variables in the model.

6.2.1 Generic assumptions

Discount rate has been assumed at 7% reflecting an average real, pre-tax cost of capital for electricity generation in New Zealand.

Fuel prices:

- Gas price = $7.5/GJ
- Coal price = $4/GJ
- Diesel price = $35/GJ
- The modelling assumes no real changes in the fuel price over the evaluation period, and excludes fuel delivery costs.

A price of \$20/tCO_2e for the cost of carbon has been assumed over the project evaluation period.

6.2.2 Plant specific assumptions

Table 6.1 contains the assumptions contained in the LRMC model. These assumptions have been derived from a number of sources as follows.

Heat rate

With the exception of New Plymouth[27], the heat rates have been sourced from the Commission GEM input assumptions[28].

No degradation or recovery of heat rate at outages or life extension refurbishment.

Net Capacity Factor (NCF)

The same net capacity factor has been assumed for all years a plant is operating. CCGT plant has been assumed to operate in a baseload regime and has a representative NCF of 80%. Huntly units 1-4 are assumed to operate in an intermediate role, as well as hydro firming and average NCF over the evaluation period assumed to be 60%. P40 and Southdown E105 unit are assumed to provide a peaking/intermediate role hence a 40% NCF. Whirinaki's role of reserve generation has been assigned a 1% NCF.

Initial plant capital costs

Sourced from GEM input assumptions.

O&M costs

Variable O&M costs have been sourced from GEM input assumptions.

Fixed O&M costs have been sourced from both GEM input assumptions and previous PB reports of thermal plant costs provided to the Commission.

Emissions factors

Sourced from GEM input assumptions.

[27] New Plymouth Power Station Monitoring Programme Annual Report. Taranaki Regional Council. 2005-2006
[28] http://www.electricitycommission.govt.nz/pdfs/opdev/transmis/soo/pdfssoo/2008/GEM-input-data.xls

Design Life

The design life for Huntly (Units 1-4) and the CCGT plant has been assumed at 30 years. The smaller OCGT's have been allocated a design life of 25 years.

Mid-life refurbishment costs

Costs have been assumed at 40% of the original plant capital costs to provide a 20 year life extension to the original design life.

The mid-life refurbishment is scheduled to occur when two-thirds of the original design life has been reached.

For example:

Original design life = 30 years.

Mid-life refurbishment occurs at 66% of original design life = 20 years

Life extension of 20 years = 30 years + 20 years = 50 years total

Construction period

The CCGTs and New Plymouth have been allocated 3 year construction periods, the remaining smaller plant have been allocated a 2 year construction period. Huntly, given the number of units relative to the other plants, has been allocated a four year construction period.

Capital costs have been split evenly over the construction period.

Plant capacity

Plant capacities have been taken from the Commission's 2008 SOO.

The original design capacity of New Plymouth for all five units has been modelled.

Table 6.1 Plant specific LRMC assumptions

Assumption	Huntly (1-4)[1]	Huntly e3p	Huntly P40	TCC	Otahuhu B	New Plymouth	Southd'n CCGT	Southd'n E105	Whirinaki
Capital cost ($/kW)	2,160	1,230	1,000	1,200	1,200	920	1,200	920	920
Construction Period (Yrs)	4	3	2	3	3	3	2	2	2
Plant capacity (MW)	1,000	385	50	385	380	300	125	45	155
Net Capacity Factor (%)	60	80	40	80	80	80	40	60	1
Output (GWh/year)	5,256	2,698	175	2,698	2,663	2,102	876	158	14
Variable O&M ($/MWh)	9.6	4.25	6.4	4.25	4.25	6.4	4.25	6.4	10
Fixed O&M ($/kW/year)	60	50	90	50	50	90	50	90	90
Heat rate (kJ/kWh)	10,500	7,080	9,500	7,300	7,050	10,800	8,250	8,950	11,000
Emissions factor (tCO_2/PJ)	91,200	52,800	52,800	52,800	52,800	73,000	52,800	52,800	73,000
Design life (Yrs)	30	30	25	30	30	25	30	25	25

[1] *Modelling assumes Huntly fuelled on coal only.*

6.3 Results

The LRMC estimates produced by the model based on the above assumptions are as follows:

Table 6.2 LRMC modelling results

Plant	LRMC without refurbishment $/MWh	LRMC with refurbishment $/MWh	Difference $/MWh
Huntly (units 1-4)	118.6	118.9	0.3
Huntly e3p	94.4	94.5	0.1
Huntly P40	121.4	119.2	-2.2
Otahuhu B	95.8	95.9	0.1
TCC	97.0	97.1	0.1
New Plymouth	131.8	129.7	-2.1
Southdown CCGT	105.4	105.6	0.2
Southdown E105	115.4	113.4	-2.0
Whirinaki	443.5	441.5	-2.0

For this modelling scenario, the extension of plant operating life by 20 years and resulting extra generation, generally offsets the additional capital expenditure required, having a minimal overall effect on the LRMC.

6.4 Conclusions

The findings from the modelling tend to support the conclusion that fuel price and availability is one the main determinants of when a power plant would be decommissioned. As experienced in Europe and North America, gas and coal steam plant are already exceeding original design lives of 25 and 30 years through regular maintenance and refurbishment programmes. The design life of the equipment does not appear to be a limiting factor in predicting decommissioning date.

If a mid-life refurbishment were to include a capacity upgrade or original design efficiency improvements, they would ultimately cost more than an upgrade for purely life extension purposes, but the higher costs should be offset by the increased generation.

Considering most plant refurbishments will also result in improving the heat rate close to or better then the original design, the savings in fuel costs adds to the economic justification of extending the plant life out an additional 20 years or more beyond the original design life.

Technology improvements are another main factor affecting plant rank in the generation mix. Where more efficient plant is available they move the less efficient plant down the generation order or replace the less efficient plant completely.

Generators are incentivised by the RMA to upgrade or refurbish existing plant in favour of completely new plant at the existing site or building new plant in a new location.

An owner would normally continue to maintain and operate an asset as long as it remains profitable and achieves the required rate of return on any investment. Writing down of asset values helps to achieve this viability. Economic risks to the viability of thermal plant in New Zealand include fuel costs, carbon emissions related charges and competition from renewable forms of generation such as hydro, wind and geothermal.

7 Glossary

Term	Definition
ACC	Air Cooled Condenser
C&I	Controls and Instrumentation
Capex	Capital Expenditure
CCGT	Combined Cycle Gas Turbine
CDS	Centralised Data Set
CFB	Circulating Fluidised Bed
CO_2	Carbon Dioxide
EOH	Equivalent Operating Hours
FGD	Flue Gas Desulphurisation
GE	General Electric
GEM	Generation Expansion Model
GT	Gas Turbine
GWh	Gigawatt-hour
HHV	Higher Heating Value
HP	High Pressure
HRSG	Heat Recovery Steam Generator
kJ	Kilo joule
kWh	Kilowatt-hour
LP	Low Pressure
LRMC	Long Run Marginal Cost
MRP	Mighty River Power
MW	Megawatt
NCF	Net Capacity Factor
NOx	Oxides of Nitrogen
O&M	Operations and Maintenance
OCGT	Open Cycle Gas Turbine
OEM	Original Equipment Manufacturer
PB	Parsons Brinckerhoff
PJ	Petajoule
RMA	Resource Management Act
SOO	Statement of Opportunities
SS	Single Shaft
ST	Steam Turbine
TCC	Taranaki Combined Cycle power station

Appendix A

LRMC Model