Prepared for

Ministry of Economic Development

Fossil Fuel Electricity Generating Costs

By

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Executive Summary

This report updates sections of a similar report in May 2002 "Costs of Fossil Fuel Generating Plant" for the New Zealand Ministry of Economic Development.

In the basic analysis the following delivered fuel costs have been assumed: gas $5/GJ; sub-bituminous coal (in North Island) $3.50/GJ; bituminous coal in West Coast South Island $2.50/GJ, everywhere else $3.50/GJ; and lignite (in south of the South Island) $1.50/GJ.

With these fuel costs, total c/kWh unit costs are presented. As well as fuel costs, these unit costs provide for O&M costs and the levelising of capital costs over the life of plant. The unit costs have been estimated on a commercial basis taking into account corporate tax, and with a discount rate of 7.5% (taken to be the post-tax real WACC). The costs therefore indicate the market price of electricity that would be required to make particular types of plant commercially viable. It would however be possible to draw on the unit cost estimates given in the report in a national cost benefit analysis. Appendix A details the basis for the cost estimation and outlines how the cost estimates may be used in both commercial and national cost benefit analyses.

The table below summarises the current (2003 prices) unit cost estimates. The report also contains results of sensitivity analyses (Appendix B) and forward estimates for 2012 and 2025 (Appendix C).

Technology	MW	Unit Cost c/kWh
Combined cycle advanced gas turbine	400	5.2
Combined cycle gas turbine	250	5.6
Southland lignite, supercritical, including FGD	500	5.7
Open cycle advanced gas turbine	230	6.4
Southland lignite, supercritical, including FGD	150	7.0
Open cycle gas turbine	160	7.0
NI sub-bituminous, supercritical, including FGD	500	7.3
Bituminous, supercritical, including FGD	500	7.3
West Coast (SI) bituminous, supercritical, including FGD	150	7.5
West Coast (SI) bituminous, subcritical, including FGD	150	7.7

Of the options examined, combined cycle gas turbine plant, at about 5.2c/kWh is estimated to be the lowest cost option for generating electricity. The use of lignite in the South Island, at around 5.7c/kWh, appears to be the next least costly option. However, this is for a 500MW plant, and this may be larger than required for the South Island market. If the power were to be transmitted to the Auckland region of the North Island, transmission costs and losses could add about 1c/kWh to the cost.

Electricity generated from sub-bituminous coal in the North Island would cost around 7c/kWh. The exact cost would depend on a range of factors, including whether it was necessary to install flue gas desulphurisation (FGD).

Of the options examined, the use of West Coast South Island bituminous coal appears to be the most costly. This option has been examined for a 150MW plant, and the relatively high c/kWh cost is attributable to dis-economies of scale with such a small plant. Although the output from a West Coast power station is likely to be used in the West Coast area and localities in the South Island, if the last MW of generation from a West Coast power station were to meet demand in the Auckland region, transmission costs and losses would increase the cost by about 0.75c/kWh.

FGD is included in coal fired plant estimates. If low sulphur coal is available and FGD is not required, unit cost estimates for the coal fired plant are reduced by about 0.6 c/kWh.

If carbon charges are introduced, these will affect fuels differentially. A carbon charge of \$15/tonne CO_2 would add about 0.7c/kWh to gas fired electricity generation costs, about 1.2c/kWh to the cost of electricity from bituminous and sub-bituminous coal and about 1.3c/kWh to the cost of lignite sourced electricity.

As well as costs, lead times for putting different technologies vary, and these may also play a significant role in developers' commercial decisions on what projects to proceed with. The table below gives an indication of the lead times to commission plant using the different technologies considered in this report.

Technology	**Total Lead Times (Months)**		
	Likely	**Minimum**	**Maximum**
Open cycle gas turbine	33	23	41
Combined cycle gas turbine	57	38	77
Coal plant	79	60	109

The lead times in the table cover the periods from project conception to commercial operation. Various coal technologies have been costed (using lignite, sub-bituminous or bituminous coal; with subcritical or supercritical boilers; with or without FGD), but all are considered to have similar lead times.

As the table shows, lead times can vary widely, but are likely to be around two and a half years for an open cycle gas turbine, around four and a half years for a combined cycle gas turbine and around six and a half years for a coal fired station.

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1 Introduction

The following report has been prepared by East Harbour Management Services in response to a request by the New Zealand Ministry of Economic Development (MED) to update sections of a similar report supplied in May 2002. The report sets out costs and performance for a selection of fossil fuelled electricity generating technologies likely to be used over the next 25 years.

2 Technologies

Technologies have been chosen that are expected to be included internationally in fossil fuelled electricity generating plant over the next 25 years with a focus on those currently commercially available. These technologies are:

- Supercritical pulverized coal fired boiler (using bituminous or sub-bituminous coal, or lignite) with or without flue gas desulphurization (FGD)
- Natural gas fired combined cycle gas turbine
- Natural gas fired advanced gas combined cycle turbine
- Natural gas fired gas turbine
- Natural gas fired advanced gas turbine.

The size of plant included in this study is limited to that likely to be used for wholesale generation of electricity. Significant changes since the May 2002 report are:

- Trend towards supercritical boiler and turbine plant with slightly higher capital cost but greater efficiency.
- Generally higher fuel prices.
- Higher gas turbine efficiencies.
- Lower FGD costs.
- Change in currency exchange rate (to $NZ1 =US$0.60 from US$0.42).
- Costing for larger coal fired plant (500MW instead of 400MW) and for larger advanced gas turbine plant (230MW instead of 120MW). This is in line with the trend overseas for larger plant while recognising the New Zealand situation and its limited ability to cope with large unit sizes of plant. The same size advanced combined cycle gas turbine plant, using a state of the art advanced gas turbine, has been costed. A smaller combined cycle gas turbine plant, using a conventional design gas turbine (250MW instead of 400MW) has been costed. Conventional gas turbines are generally smaller than state of the art advanced machines.
- Inclusion of costing for a range of coals of varying rank, and for a 150 MW coal fired plant on the West Coast of the South Island. It is probable that this is the maximum size of plant that could be accommodated without major upgrades of the transmission system from the West Coast.

Capital costs, plant efficiencies and operating and maintenance costs for the chosen technologies are given in Table 1.

Overseas cost data has been adjusted for New Zealand conditions. The adjustment procedure is outlined in Appendix D, with all costs adjusted to New Zealand dollars as at September 2003. The costs are indicative only and individual plant costs will vary according to the site, special conditions and constraints. Typical plant sizes have been chosen.

Points to note:

- The unit cost of electricity is a levelized cost estimated in a commercial context with a 7.5% discount rate (taken to be the post-tax real WACC). Levelized cost is the time value of all costs converted to a uniform series of deposits spread over the entire life of the investment. It takes into account the total discounted cost of producing the electricity (capital, operating and maintenance and fuel costs) and the total amount of electricity produced over the life of the plant, and distributes these costs over the operating life of the station. This levelized cost is matched by revenue from the sale of electricity which is taxed at the company tax rate (33%). However, this tax is partly offset by the asset depreciation tax shield. This net tax position is shown as “Tax” in Tables 2 and 3 in this report and “Other” in the May 2002 report. Appendix A provides a detailed explanation of how the unit costs have been derived. Although the unit costs have been estimated in a commercial context, this appendix indicates how the estimates could also be used in a national cost benefit analysis.

- The output and efficiencies quoted for gas-fired plant apply for a natural gas fuel. Natural gas firing gives a slightly higher output than distillate firing. The efficiency is also slightly higher (by about 3%) when burning gas as opposed to distillate, i.e. multiply the efficiency given in the text by say 0.97 for firing by distillate.

- No carbon charges have been included in the fuel costs.

- The capital costs quoted generally apply only to plant that is close to the size of plant specified. For generating plant with a different MW output, capital cost scaling factors are outlined in Appendix E.

- Costs do not include investigations, obtaining resource consents, transmission costs and losses.

- All efficiencies are based on the higher (or gross) heating value (HHV) of the fuel to enable direct comparisons to be made between the technologies. The difference between this and the lower (or net) heating value is the release of heat from the condensation of water in the products of combustion.

Table 1: Current Power Station Capital, Operating and Maintenance Costs, and Efficiency

Technology	Size	Capital Cost [2]	O & M Cost [2]		Efficiency (HHV)
	MW	$/kW	Fixed $/kW	Variable c/kWh	%
Subcritical pulverized coal (bituminous) with FGD[1]	150	2420	31	0.31	34
Supercritical pulverized coal (bituminous) with FGD[1]	500	1850	31	0.31	38
Supercritical pulverized coal (bituminous) with FGD[1]	150	2500	31	0.31	38
Supercritical pulverized coal (lignite) with FGD[1]	500	2030	35	0.34	36
Supercritical pulverized coal (lignite) with FGD[1]	150	2750	35	0.34	36
Supercritical pulverized coal (sub-bitum.) with FGD[1]	500	1920	31	0.31	38
Combined cycle gas turbine	250	830	17	0.21	47
Combined cycle advanced gas turbine	400	940	14	0.21	54
Open cycle gas turbine	160	630	14	0.41	33
Open cycle advanced gas turbine	230	720	12	0.31	37
Note 1: For a pulverized coal plant without FGD deduct $170/kW from the capital cost. O & M costs are reduced by approximately 10% and there is an approximate 2% gain in efficiency.					
Note 2: Costs are in September 2003 New Zealand dollars.					

2.1 Electricity Generation Cost Estimates

Indicative current electricity generation cost estimates (2003) are shown in Tables 2 and 3. In these examples a discount factor of 7.5% has been used over a 20-year plant life. Fuel prices used are $5.00/GJ for gas, $2.50/GJ for bituminous coal on the West Coast (SI) and $3.50/GJ for elsewhere in New Zealand, $3.50/GJ for sub-bituminous coal and $1.50/GJ for lignite coal. (These prices have been discussed and agreed with the MED.) The net load factor has been assumed to be 90%. Supercritical pulverised fuel (pf) plant has assumed to be installed except for the West Coast (SI) where subcritical pf plant has also been considered. (Huntly power station is a subcritical pf plant. Gas turbines and combined cycle gas turbines recently installed in New Zealand tend to fall into the “advanced” category.) As coal plant without FGD would be an option if low sulphur coal were available, costing estimates for such plant are included (see Table 3). Cost estimate sensitivities are detailed in Appendix B.

Table 2: 2003 Electricity Cost Estimates (7.5% discount rate, 20 year life, $5.00/GJ gas, $2.50/GJ West Coast (SI) bituminous coal, $3.50/GJ sub-bituminous coal and bituminous coal in the remainder of New Zealand, $1.50/GJ lignite coal, 90% load factor)

Technology	Cost c/kWh					
	MW	Capital	Fuel	O & M	Tax	Total
Combined cycle advanced gas turbine	400	1.2	3.4	0.4	0.3	5.2
Combined cycle gas turbine	250	1.1	3.9	0.4	0.2	5.6
Southland lignite, supercritical, with FGD	500	2.7	1.5	0.8	0.7	5.7
Open cycle advanced gas turbine	230	0.8	4.9	0.5	0.2	6.4
Southland lignite, supercritical, with FGD	150	3.7	1.5	0.8	1.0	7.0
Open cycle gas turbine	160	0.8	5.5	0.6	0.2	7.0
NI sub-bituminous, supercritical, with FGD	500	2.6	3.3	0.7	0.7	7.3
Bituminous, supercritical, with FGD	500	2.5	3.3	0.9	0.7	7.3
West Coast (SI) bitum. supercritical with FGD	150	3.4	2.4	0.9	0.9	7.5
West Coast (SI) bitum. subcritical with FGD	150	3.3	2.6	0.9	0.9	7.7

Table 3: 2003 Electricity Cost Estimates for Coal Plant without FGD (7.5% discount rate, 20 year life, $2.50/GJ West Coast (SI) bituminous coal, $3.50/GJ sub-bituminous coal and bituminous coal in the remainder of New Zealand, $1.50/GJ lignite coal, 90% load factor)

Technology	Cost c/kWh					
	MW	Capital	Fuel	O & M	Tax	Total
Southland lignite, supercritical, no FGD	500	2.5	1.4	0.7	0.7	5.3
Southland lignite, supercritical, no FGD	150	3.4	1.4	0.7	0.9	6.4
Bituminous, supercritical, no FGD	500	2.3	3.1	0.8	0.6	6.8
NI Sub-Bituminous, supercritical, no FGD	500	2.4	3.2	0.6	0.6	6.8
West Coast (SI) bituminous, supercritical, no FGD	150	3.1	2.2	0.8	0.8	6.9
West Coast (SI) bituminous, subcritical, no FGD	150	2.9	2.5	0.8	0.8	7.0

2.1.1 Carbon Charge

A carbon charge has not been included in the above estimates. However to illustrate the effect of say, a $15/tonne carbon dioxide emission charge, the estimated cost of electricity generated from gas would increase by about 0.7 c/kWh, from bituminous and sub-bituminous coal, 1.2 c/kWh and lignite 1.3 c/kWh.

2.1.2 Technology Lead Times

As well as costs, lead times from project conception to commercial operation have been considered. These can have a significant effect on the viability of any electricity generating plant project. Appendix F gives details of the analysis and indicative lead times for the different technologies are summarised in Table 4.

Table 4: Technology Lead Times

Technology	Total Lead Times (Months)		
	Likely	Minimum	Maximum
Open cycle gas turbine	33	23	41
Combined cycle gas turbine	57	38	77
Coal plant	79	60	109

Lead times can vary widely, but are likely to be around two and a half years for an open cycle gas turbine, around four and a half years for a combined cycle gas turbine and around six and a half years for a coal fired station.

3 Discussion

Combined cycle gas turbine plant, at just over 5 c/kWh (for a fuel cost of $5/GJ), continues to be the lowest cost option for fossil fuelled electricity generating plant. Advanced open cycle gas turbine and Southland lignite fired plant are the next cheapest. If FGD is not required the Southland lignite plant is only slightly more expensive than the advanced CCGT. The lignite fired plant has a much higher capital cost/kW but this is more than compensated for by the cheap fuel. Economies of scale are illustrated by the 1.0 c/kWh higher capital charge for the 150 MW lignite plant over the 500 MW plant. The plant on the West Coast (SI) comes out relatively costly overall as a result of its higher capital cost/kW (because of its lower MW output), assumed higher coal sulphur levels and an assumed higher coal price.

Whilst plant based in Southland is estimated to be the cheapest coal fuelled option it should be recognised that the bulk of the electricity load is in the northern half of the North Island and the cost of losses etc associated with transporting the electricity to the load needs to be taken into account. It should be noted that, while average transmission losses over the North and South Island networks, including the HVDC link, tend to vary between 5.5 and 6.5 %, the magnitude of the marginal losses can at times be high, reaching 5–10% over the South Island, 10-15% over the HVDC and 20-30% over the North Island[1], effectively making it less competitive with electricity generated from Huntly coals.

Transmission losses can be quite variable in both the short-term, as well as over longer periods where increasing demand, new generation and transmission upgrades will change the mix of factors that influence transmission losses and hence the associated electricity prices at the points of demand. With the cost of these losses assessed on a marginal loss basis, the increase in price for electrical energy can, even when the half-hourly price is 6 c/kWh at the grid injection point in say, Southland, or the West Coast, be as much as 3c/kWh. However, it is more likely that losses for generation in the Southland or West Coast regions of the South Island that effectively responds to a demand increase in the Auckland region will be above, but closer to, the average losses than the high marginal losses referred to earlier. From the more detailed assessment of

[1] Extract from Footnote 33,Volume II: Wholesale Market, of the Transpower submissions to the 2000 Electricity Inquiry

losses in Appendix G it can be inferred that the cost of losses for this scenario is about 0.75 to 1 c/kWh.

500 MW is a large generating source for Southland and would require large loads such as another smelter or pulp and paper mill to take a large portion of the generation to limit the need to transport power northward. A smaller sized plant, say 150 MW, may provide a better increment of generation in this region, but has a higher capital cost/kW with an estimated unit cost of 7.0 c/kWh, an increase of 1.3 c/kWh over the 500MW plant.

4 Future Unit Costs

Cost estimates given in the Tables 5 and 6 and the tables and figures in Appendix C have "learning" factors built into them. These take into account the reductions in cost that occur as plants move from the demonstration stage to initial commercialisation (where a few units are built) to full commercialisation (where many such plants are built). Technological improvements that are expected to occur, such as increased efficiency, are also included.

"Low" and "high" technology uptake scenarios have been included to indicate the spread of values with the "expected value" the most likely case.

In the "low" technology uptake scenario, the costs and efficiencies of advanced generating technologies (i.e. Advanced Gas Combined Cycle and Advanced Combustion Turbine) remain at current levels. Learning is applied to the "expected" technology cases. In the "high" technology uptake scenario, efficiencies of advanced fossil generating technologies are based on the United States Department of Energy, Office of Fossil Energy's Vision 21 programme (http://www.fe.doe.gov/programs/powersystems/vision21/) goals. This scenario represents the upper limits of efficiencies considered to be achievable within the period through to 2015.

Vision 21, builds on a portfolio of technologies already being developed, including low-emissions combustion, gasification, high efficiency furnaces and heat exchangers, advanced gas turbines, fuel cells, and fuels synthesis, and adds other critical technologies and system integration techniques.

Capital costs and efficiencies for each of the technologies will be dealt with in turn. Tables 5 and 6 show the estimated generation costs in 2012 and 2025. The costs are sensitive to changes to capital, fuel and O&M costs, plant factors and discount rates. O&M and fuel costs have been kept at the same level as the 2003 cases.

The effects of the capital costs and efficiency changing through time are shown in more detail in Appendix C. The effects of capital cost and changes in efficiencies of these on the various unit cost components are also shown in tabular as well as graphical form.

Table 5: 2012 Electricity Cost Estimates (7.5% discount rate, 20 year life, $5.00/GJ gas, $3.50/GJ bituminous coal, 90% load factor)

Technology	Cost c/kWh					
	MW	Capital	Fuel	O & M	Tax	Total
Combined cycle advanced gas turbine	400	1.1	3.4	0.4	0.3	5.1
Combined cycle gas turbine	250	1.0	3.7	0.4	0.2	5.4
Open cycle advanced gas turbine	230	0.8	4.5	0.5	0.2	5.9
Open cycle gas turbine	160	0.7	5.5	0.6	0.2	7.0
Bituminous supercritical with FGD	500	2.4	3.2	0.9	0.6	7.1

Table 6: 2025 Electricity Cost Estimates (7.5% discount rate, 20 year life, $5.00/GJ gas, $3.50/GJ bituminous coal, 90% load factor)

Technology	Cost c/kWh					
	MW	Capital	Fuel	O & M	Other	Total
Combined cycle advanced gas turbine	400	1.1	3.4	0.4	0.2	5.0
Combined cycle gas turbine	250	1.0	3.7	0.4	0.2	5.4
Open cycle advanced gas turbine	230	0.7	4.5	0.5	0.2	5.8
Open cycle gas turbine	160	0.7	5.5	0.6	0.2	7.0
Bituminous supercritical with FGD	500	2.3	3.2	0.9	0.6	7.0

4.1 Technological Trends – Commentary

Technological trends in fossil fuelled electricity generating plant are being driven by the need to reduce environmental discharges, and reduce operating costs. The need to have technologies that reduce the cost of reducing or sequestering carbon dioxide emissions is also a driver. This increases the requirement for greater efficiency and, as the technology matures, to be competitive in the market place. The technology that is followed will be determined to some degree by the relative delivered costs of natural gas and coal.

Hybrid plants using a mixture of gas turbine and coal plant of varying configurations will continue to be investigated. An example of this is to use the exhaust from a gas turbine as a feed heating source for a supercritical pf plant.

4.1.1 Coal Based Technologies

Pulverized Coal

In a conventional plant pulverised coal is burnt in a boiler to produce steam, which is fed into a steam turbine coupled to an electrical generator. Emission controls such as electrostatic precipitators or bag houses, and flue gas desulphurisation (FGD) limit pollutants (particulates, sulphur and nitrogen oxides) to permitted levels. A typical example of this type of plant is Huntly power station (except that it does not have FGD because of low sulphur levels in NZ sub-bituminous coals).

Plant designs with advanced steam parameters have generally not been favoured by the regulated U.S. market economics until relatively recently. In Europe and Japan supercritical pressure designs are more common and have proven experience. Advances in materials development are facilitating design of steam power cycles with higher efficiencies.

The increased need for greater efficiency and operating benefits are favouring supercritical plant. Further advances in materials will lead to even higher pressures and temperatures, the so called advanced or ultra supercritical plant with an efficiency of about 44%. More effective environmental controls will also be a feature of future plants. (A brief description of the difference between a subcritical and a supercritical boiler is given in Appendix H.)

Fluidized Bed Boiler

Fluidised beds suspend solid fuels on upward-blowing jets of air during the combustion process. The result is a turbulent mixing of gas and solids, much like a bubbling fluid. The mixing action of the fluidised bed brings the flue gases into contact with a sulphur-absorbing chemical, such as limestone or dolomite. More than 95 percent of the sulphur pollutants in coal can be captured inside the boiler by the sorbent.

Fluidized bed boilers can burn almost any combustible material, from coal to municipal waste, and are capable of meeting sulphur dioxide and nitrogen oxide emission standards without the need for expensive add-on controls.

Fluidized bed combustion (FBC) is often seen as an alternative to pf firing. This technology has some inherent environmental advantages over pf firing; lower NOx emissions without the need for special equipment and the ability to burn coals with a range of sulphur content without separate FGD equipment.

Pressurised fluidized bed boilers offer the potential of higher efficiencies but appear to be out of favour in the USA and UK.

Gasification

Rather than burning coal directly, coal gasification reacts coal with steam and controlled amounts of air or oxygen under high temperatures and pressures to produce a gaseous mixture, typically hydrogen and carbon monoxide. These hot, coal gases exiting the gasifier are used to power a gas turbine (in the same manner as natural gas). Hot exhaust from the gas turbine is then fed to a heat recovery steam generator (HRSG). The steam from the HRSG is then fed to a conventional steam turbine, producing a second source of power (just as in a combined cycle plant).

Pollutant-forming impurities and greenhouse gases can be separated from the gaseous stream. Unreacted solids can be collected and marketed.

Integrated gasification combined cycle (IGCC) plant is used in a large number of refinery and chemical industry facilities using primarily petroleum feedstocks. The transfer of IGCC technology using coal as a feedstock for electricity generation has not been as successful. Demonstration plants have had higher costs and lower efficiencies than expected. This technology is considered to be an emerging one.

IGCC has a number of potential benefits: high efficiency, can handle high sulphur coals, emissions similar to gas firing and the potential for carbon dioxide capture. It is receiving considerable interest and funding by US Federal agencies with a target of having similar costs to pf plant.

The syngas from the gasifier contains significant amounts of hydrogen so the gas after treatment has the potential for use in fuel cells. The hydrogen and sulphur could also be removed and used as a chemical feedstock for the manufacture of methanol, ammonia, fertilizers and other chemicals.

4.1.2 Gas Based Technologies

Open Cycle Gas Turbine (Combustion Turbine)

Combustion of the fuel produces a high-temperature, high-pressure gas working fluid. When this is exhausted through a gas turbine this causes the shaft to rotate by expanding the gas through a series of specially designed blades. The rotating shaft drives an electric generator and a compressor for the inlet air used by the gas turbine. Many turbines also use a heat exchanger called a recuperator to add turbine exhaust heat into the combustor's air/fuel mixture.

Gas turbines are compact, lightweight, easy to operate, and come in sizes ranging from several hundred kilowatts to hundreds of megawatts.

Examples of this type of plant are the earlier gas turbines at Otahuhu power station. Current gas turbines are more efficient.

Open Cycle Advanced Gas Turbine

This type of gas turbine can operate at higher temperatures through the use of more exotic materials, sophisticated cooling and other enhancements to achieve higher efficiencies.

Combined Cycle Gas Turbine

Fuel, generally natural gas (but can be other gaseous or liquid fuels), is burned in a gas turbine coupled to an electrical generator. The exhaust (a hot gas stream) from the gas turbine is then passed into a heat recovery steam generator (HRSG), which can be fired or unfired. The steam is then fed to a conventional steam turbine to provide a second source of power. Otahuhu B Power Station and Taranaki Combined Cycle Power Station at Stratford are examples of this type of plant but at the time of ordering they would have been considered to be more in the advanced class of combined cycle plant.

Combined Cycle Advanced Gas Turbine

This is a type of combined cycle plant utilising higher temperatures through the use of more exotic materials and other enhancements to achieve higher efficiencies.

Developments will continue in gas turbine plant relating to increases in firing temperatures (materials and cooling techniques) multi-staged firing and the thermodynamic cycle (intercooling, reheat, and hybrid cycles).

Appendix A: The Derivation of Unit Costs and the Relevance of Particular Discount Rates and Unit Costs for Different Types of Analysis

A.1 National Cost Benefit Analysis

In national cost benefit analyses, it can be useful to assess the c/kWh unit costs of different proposed or possible new sources of generation.

The fuel and variable O&M costs are readily expressed in c/kWh terms and these costs are relatively unambiguous whatever the utilisation pattern of the plant; whether the plant is base loaded or used only occasionally, the same unit costs apply.

A.1.1 Estimating Unit Capital Costs

The conversion of capital costs and fixed O&M costs into c/kWh terms requires two steps:

- annuitising the capital costs into equivalent annual costs and adding the annual fixed O&M costs (this is sometimes called levelising the costs), and
- spreading the total of these annual costs over the number of units to be generated in a year.

The annuity is the annual payment that will recover the capital cost of the plant over a specified project life and earn a given rate of return in the process. Expressed differently, the present value of the annuity stream equals the (present value of) capital costs.

The annuitisation of capital costs can be derived using the normal formula that requires that the present value of payments equals the capital cost:

$$C = C.PMT[1/(1 + R) + \dots + 1/(1 + R)L]$$

where:

C = the up front capital cost

PMT = a proportional annuity factor[2], defined so that C.PMT is the equivalent annual payment to be derived

R = the real public sector discount rate, which is currently assumed to be 10%, and

L = the expected life of the investment in years.

[2] This is the "payment function" in Excel.

Note that the annuity factor is just:

$$PMT = 1/[1/(1 + R) + \ldots + 1/(1 + R)^{L}] = R/[1 - (1 + R)^{-L}].$$

Conversion of the equivalent annual costs into c/kWh unit costs depends on load factors. In this report, 90% load factors are used in the base case, but results are also given for 60% load factors.

A.1.2 Construction and Commissioning Periods

Various technologies require differing times for construction and this can spread over several years, during which time capital costs are incurred. Generally civil costs are incurred at an early stage in the project and the mechanical and electrical costs in the latter stages. The modelling of capital costs for this report uses annual steps, and the capital expenditure for coal plant has been spread over three years, combined cycle gas turbines two years, and open cycle combustion turbines one year.

Commissioning (ramping up to full GWh capability) can be also be spread over a period, in some cases up to 12 months or more, particularly with multiple units or staged construction. In the cases considered here, because they are single units, generation build up is assumed to take place over one quarter of the commissioning year except for coal plant when generation build up is over two quarters.

A.1.3 What Cost Estimates to Use in a National Cost Benefit Analysis?

All the unit cost estimates in this report are in real (not nominal) terms.

In a national cost benefit analysis (cba) it would be appropriate to use the c/kWh capital, fuel and O&M costs (but not tax costs) that are provided for a 10% discount rate.

A.2 Commercial Analysis

In New Zealand, investments in generating plant do not proceed on the basis of national cost benefit analyses. Decisions on whether or not to invest are made on a commercial basis. Accordingly, in assessing what plants are likely to be built and in which order (assuming lower cost options are built first), commercial criteria should be applied. Note that the total unit cost of a plant indicates the market price of electricity that would be required for the plant to be economic.

A.2.1 Estimating Unit Capital Costs

In a commercial setting, the investor requires that the present value (at a competitive investor's Weighted Average Cost of Capital (WACC)) of the post-tax cash flow arising from the annual payments equals at least the up front capital cost. (The investor may also consider that there are risks that are not allowed for by the WACC, and therefore seek a premium on the WACC.) The unit cost derived from the annual payment figure is then the price that would earn the investor a competitive rate of return, post-tax.

Compared with a national cost benefit analysis, there are two differences:

- instead of using the public sector discount rate it is necessary to use the investor's post-tax WACC, and
- it is necessary to provide for the fact that the returns that the investor receives will be net of tax. In a national cost benefit analysis it is assumed that tax does not constitute a loss but rather a re-distribution of income from one person to another, and as a result it is not necessary to take it into account.

It is not easy to assess the competitive investor's post-tax WACC in New Zealand. However, it is considered that a real (not nominal) post-tax WACC of 7.5% is a reasonable figure. For this reason, a discount rate of 7.5% has been chosen as the base case rate in this report.

Turning to the issue of tax, in a commercial analysis the annuitisation of capital costs requires two tax effects to be taken into account:

- the basic payment of corporate tax, which tends to increase unit costs required in order for the investor to obtain an adequate post-tax return, and
- depreciation allowances that help moderate the amount of tax that has to be paid.

Where the tax rate is t (assumed to be 33%), the basic tax effect increases the size of the annual payments required to achieve an adequate return by a factor of $1/(1 - t)$.

With straight line depreciation, the amount of tax that depreciation saves each year is t.C/L. This amount is commonly referred to as the depreciation tax shield. It is possible to calculate the present value worth of the shield by using an annuity factor. The annuity factor has the same form as that described in A.1.1, but in this case because tax has to be paid and the shield operates on nominal (not real) income, the relevant annuity factor is that for the post-tax nominal WACC; call it PMT'. Then the present value of the shield is t.C/(L.PMT'), and this effectively reduces the up front capital cost from C to C(1 – t/(L.PMT')).

In preparing this report it has been assumed that inflation is 2% pa. Accordingly, this has been taken into account in preparing nominal income figures, and nominal WACCs. For example, the post-tax nominal WACC corresponding with the post-tax real WACC of 7.5% is (1.02 x 1.075 – 1) = 9.7%.

It is now necessary to annuitise this capital cost and also take into account the $1/(1 - t)$ tax factor. Here it is normal to calculate the equivalent annual payments in real terms since it is assumed that the ultimate price calculated keeps up with inflation. Accordingly, the relevant annuity factor in this case is that for the investor's post-tax real WACC. (Note this is not the same PMT as in Part 1; there the PMT was that for the public sector discount rate.) The resulting annuitised capital cost is then given by:

$$PMT.C(1 - t/(L.PMT'))/(1 - t) = C.PMT + t.C.PMT(1 - 1/(L.PMT'))/(1 - t).$$

The first component of the last expression (C.PMT) corresponds to the annuitised capital costs given in this report, while the second component corresponds to the annuitised tax costs. The capital and tax c/kWh unit costs have been derived from such components.

The treatment above is a simplified approach that assumes a single representative life for all assets and straight line depreciation. The capital and tax unit costs given in the body of the report have been calculated after taking into account a number of factors such as construction and commissioning periods (see below).

As mentioned in A.1.1, the load factors have to be taken into account in converting equivalent annual costs into unit costs.

A.2.2 Construction and Commissioning Periods

As outlined in A.1.2, the effects of these periods extending over several quarters or years have been taken into account in preparing the unit capital unit costs. The capital unit cost estimates can be used in either a national cost benefit analysis or a commercial analysis (providing the appropriate discount rate is chosen). Tax costs need to be included in a commercial analysis. Since tax costs are driven off capital costs, the effects of construction and commissioning periods are also built into their estimation.

A.2.3 What Cost Estimates to Use in a Commercial Analysis?

In a commercial analysis it would be appropriate to use the c/kWh capital, fuel, O&M and tax costs given in this report. As mentioned above, it is somewhat difficult to know what discount rate to use. It is suggested that, unless there is specific evidence for using a different rate, the 7.5% base case rate of the report be used. This should be interpreted as a post-tax real WACC.

In A.1.3 it was suggested that the unit cost estimates given in the report for capital, fuel and O&M costs for a 10% discount rate would be appropriate to use in a national cost benefit analysis (cba). A question that might be posed is how this is the case when the commercial analysis involves tax effects that are not relevant in a cba.

The reason is as follows. With respect to unit capital costs, the effect of tax is separated out into the unit tax cost which should not be included in a cba. With respect to fuel and O&M unit costs, tax does no affect these. In a commercial context an investor would gain the tax benefit of expensing cost such that the effective cost was actual expenditure factored down by (1 – t). But then in order for the investor to gain an adequate rate of return post-tax the income received has to be the effective cost factored up 1/(1 – t). Thus the net tax effect is zero, and the relevant unit cost in a commercial analysis is equal to the actual unit cost, the same unit cost as relevant in a cba. Although, as noted elsewhere, different discount rates are likely to be appropriate in the two types of analysis.

Another question is whether the cost estimates given in this report are directly comparable to those given elsewhere, for example in the UK report cited in the bibliography, The Cost of Generating Electricity. Clearly circumstances in the UK differ from those in NZ. Also, it is not entirely clear on what basis the UK report has been prepared. It uses a nominal discount rate of 7.5%, and this suggests that it is a commercial analysis, but there does not appear to be any reference to tax so this may not be the case. Caution should be exercised in comparing results from different sources, especially where all the assumptions are not fully specified.

Appendix B: Electricity Generation Cost Sensitivities

Variations in plant cost, finance, operating and maintenance costs, and operating regime affect the electricity generating costs to differing degrees. Sensitivity to the unit cost to changes in these inputs is shown in the tornado diagrams for the options given previously.

The variations chosen are:

Capital Cost -10% and +25%

O&M ± 20%

WACC 5% and 10% (base level is 7.5%)

Load factor 60% (base level is 90%)

Fuel costs

- Gas 4.50 $/GJ and 6.00 $/GJ (base is 5.00 $/GJ)
- Bituminous coal on the West Coast (SI) 2.00 $/GJ and 3.00 $/GJ (base is 2.50 $/GJ)
- Bituminous coal elsewhere in NZ, 3.00 $/GJ and 4.00 $/GJ (base is 3.50 $/GJ)
- Sub-bituminous coal 3.00 $/GJ and 4.00 $/GJ (base is 3.50 $/GJ)
- Lignite coal 1.00 $/GJ and 2.00 $/GJ (base is 1.50 $/GJ)

The unit cost range in the tornado diagrams is the same for all cases to allow direct comparisons to be made (except for the gas costs which cover a 1.50 $/GJ range instead of coal's 1.00 $/GJ range.)

The tornado diagrams are arranged in increasing order of lowest to the highest base unit cost for all plant except the coal fired plant without FGD. These have been placed at the end. Tornado diagrams place the most sensitive parameter at the top of the diagram and the least sensitive at the bottom.

It can be seen that in the gas turbine based technologies fuel cost followed by load factor are the most sensitive parameters. Whereas, for coal based technologies load factor followed by WACC are the most sensitive parameters.

Figure B1: Advanced Combined Cycle Gas Turbine (400 MW)

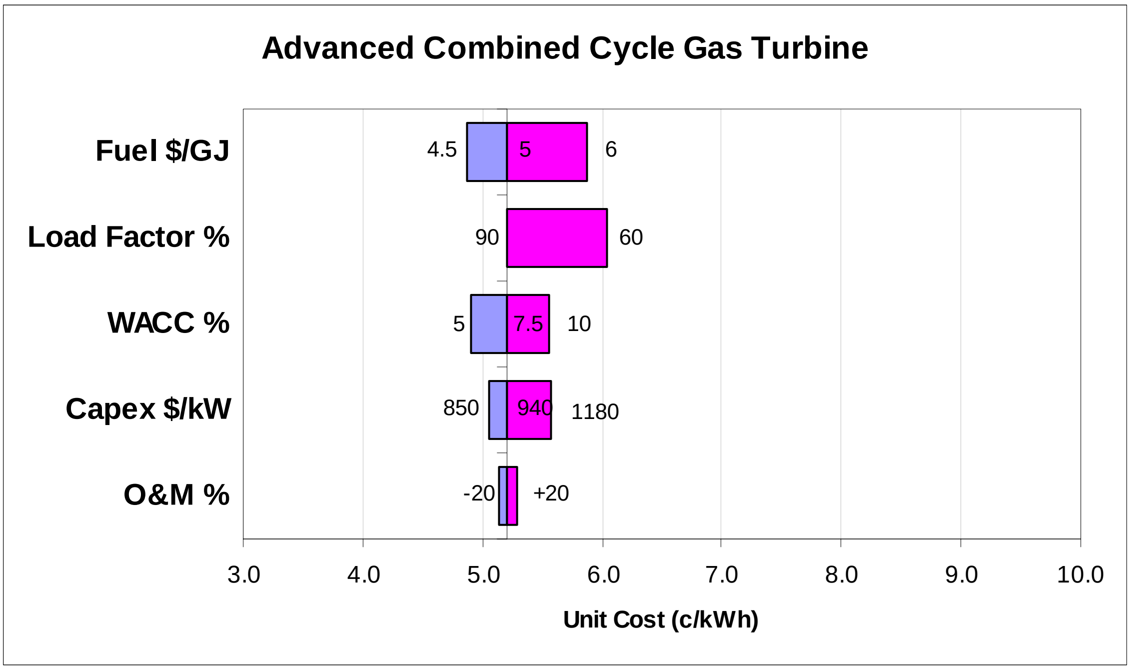


Figure B2: Combined Cycle Gas Turbine (250 MW)

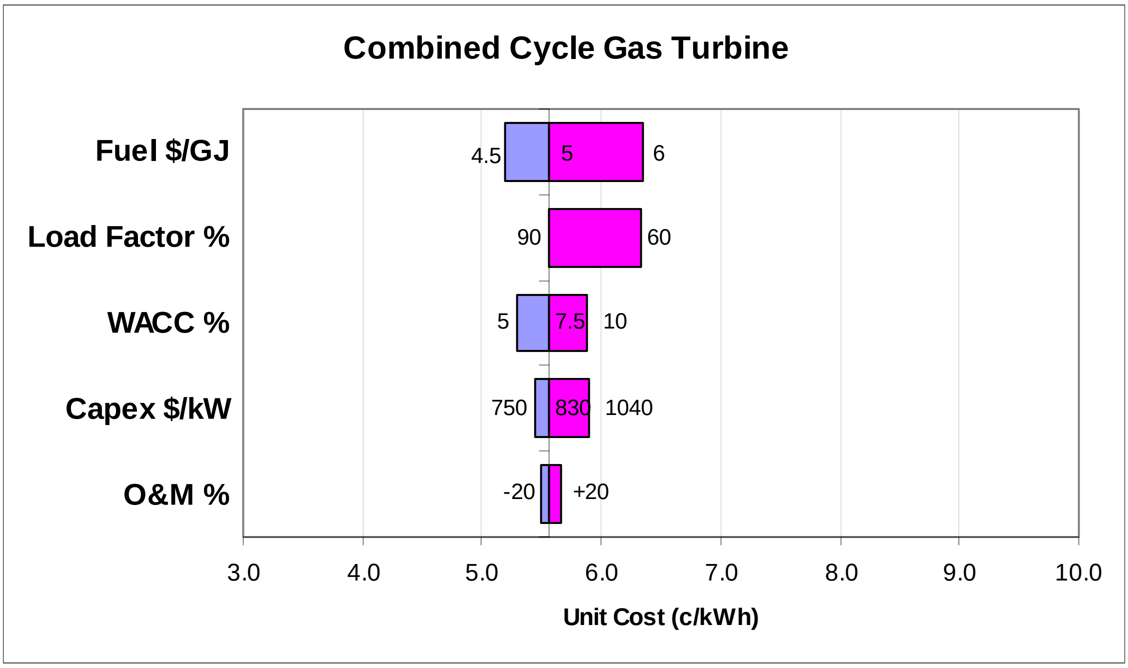


Figure B3: Southland Lignite Coal with FGD (500 MW)

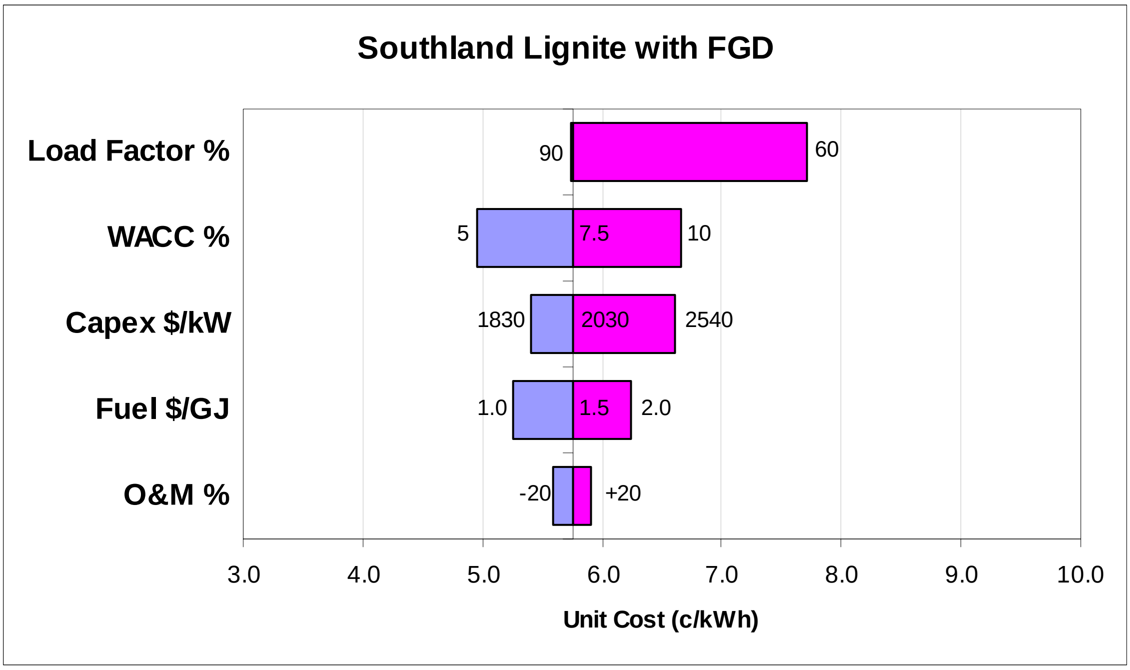


Figure B4: Advanced Open Cycle Gas Turbine (230 MW)

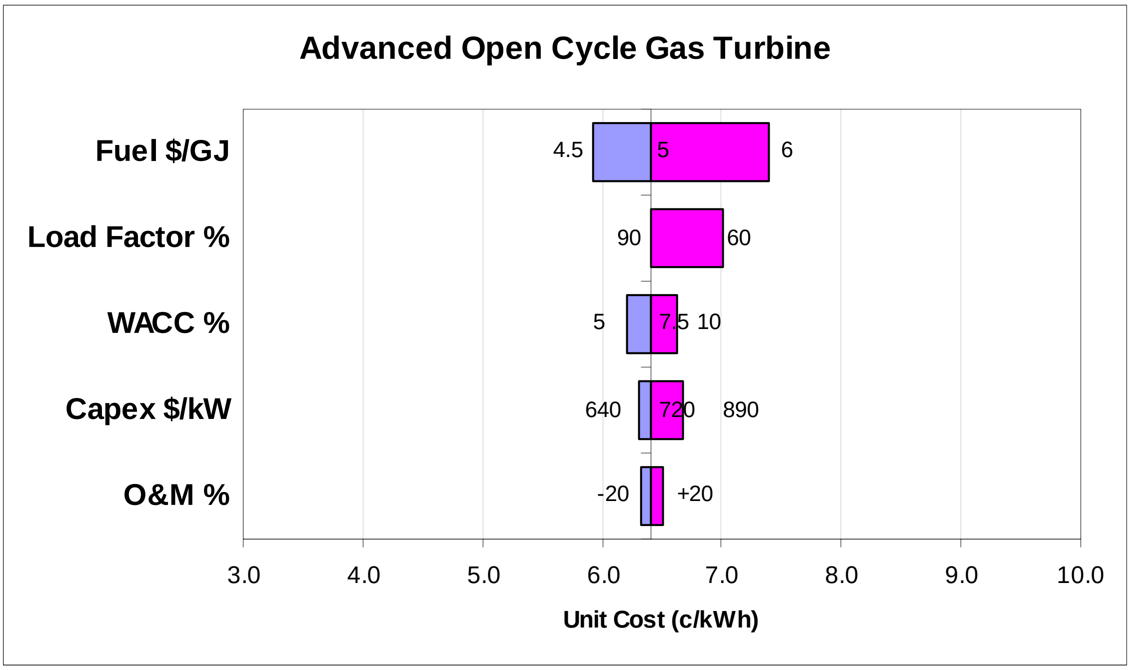


Figure B5: Southland Lignite Coal with FGD (150 MW)

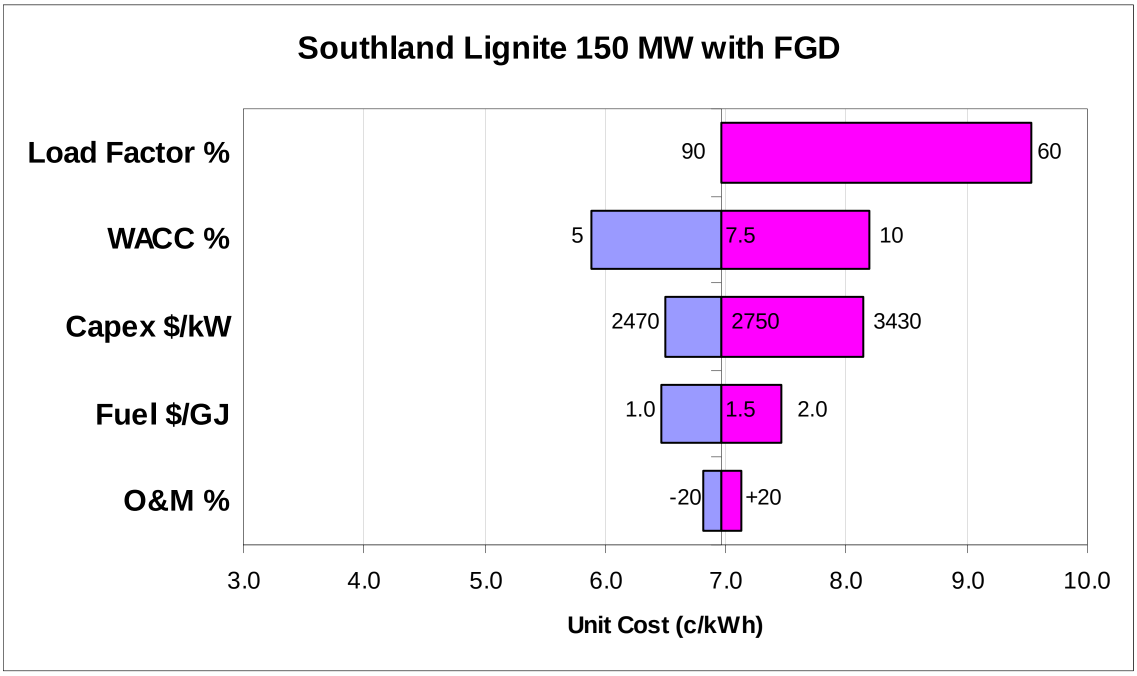


Figure B6: Open Cycle Gas Turbine (160 MW)

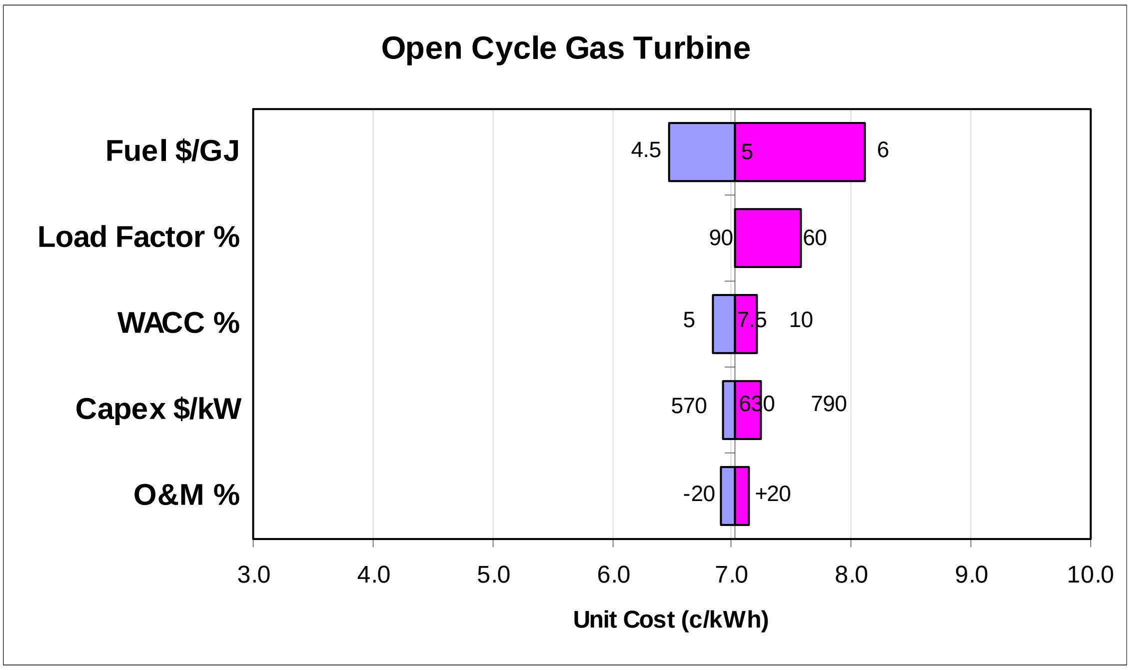


Figure B7: North Island Sub-bituminous Coal with FGD (500 MW)

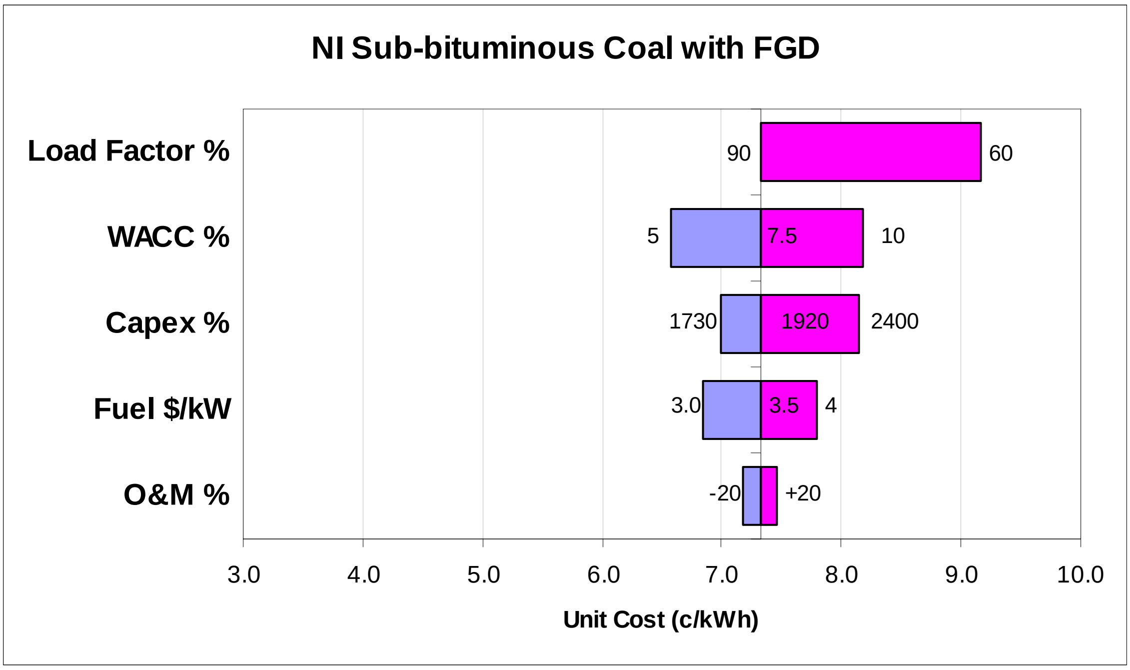


Figure B8: Bituminous Coal with FGD (500 MW)

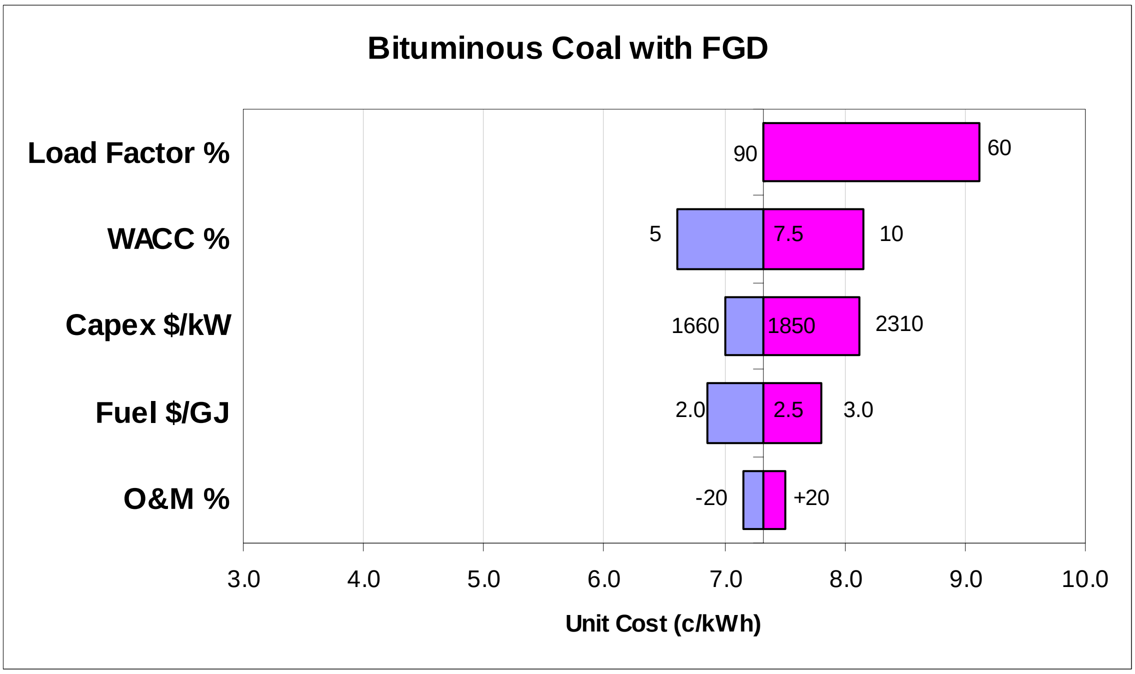


Figure B9: West Coast (SI) Bituminous Coal with FGD (150 MW)

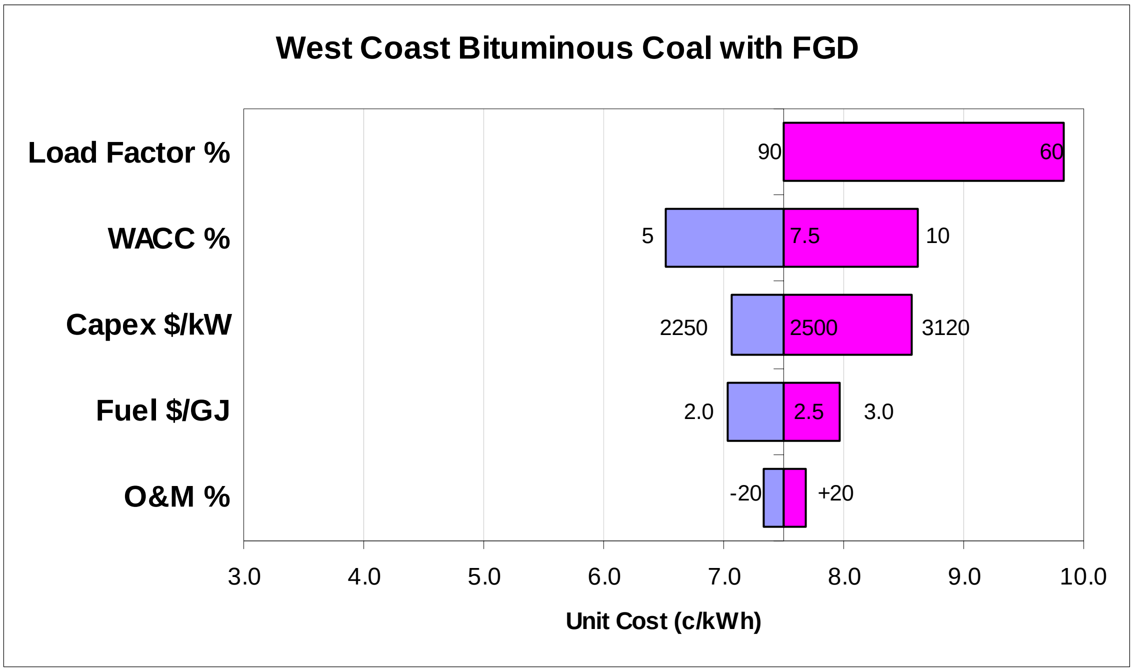


Figure B10: West Coast (SI) Bituminous Coal, Subcritical with FGD (150 MW)

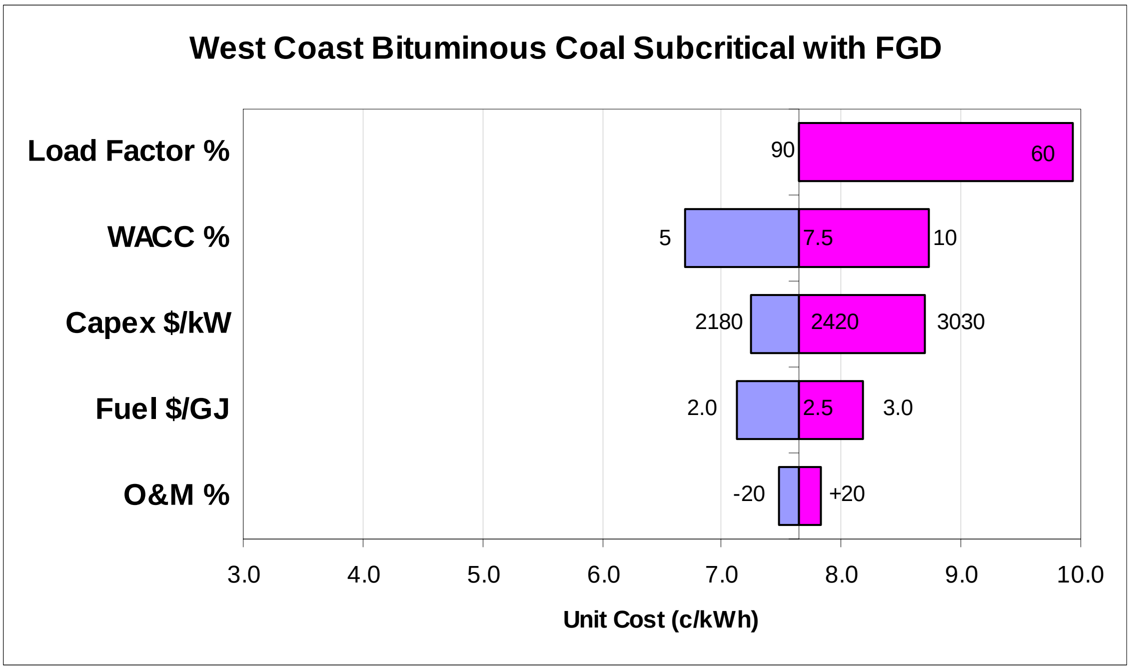


Figure B11: Southland Lignite Coal without FGD (500 MW)

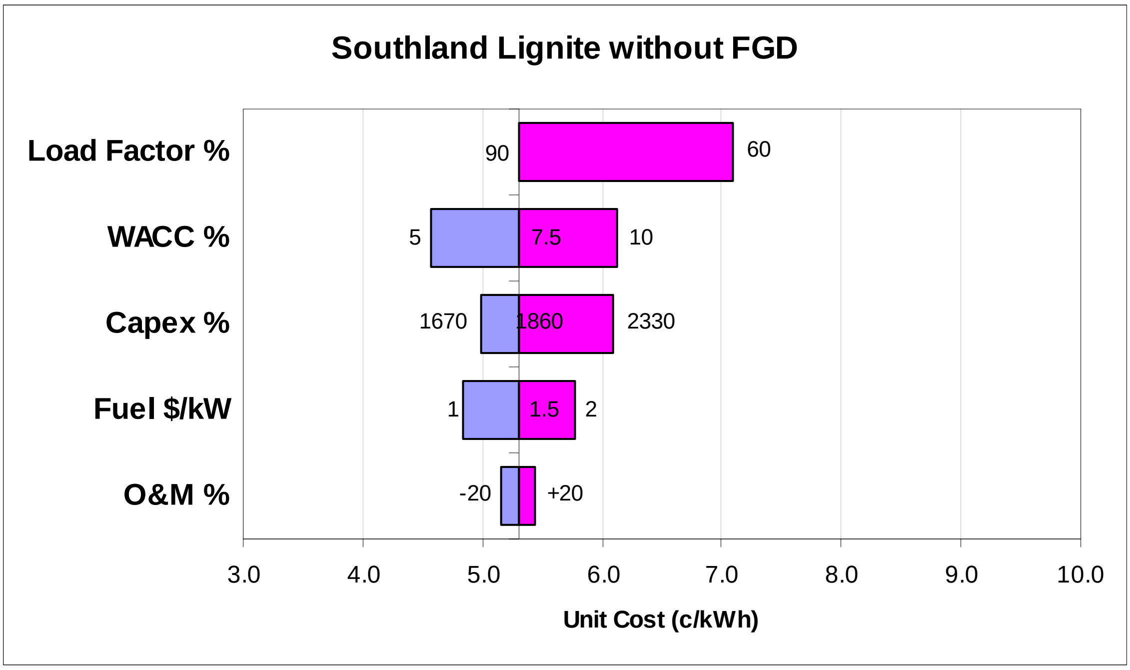


Figure B12: Southland Lignite Coal without FGD (150 MW)

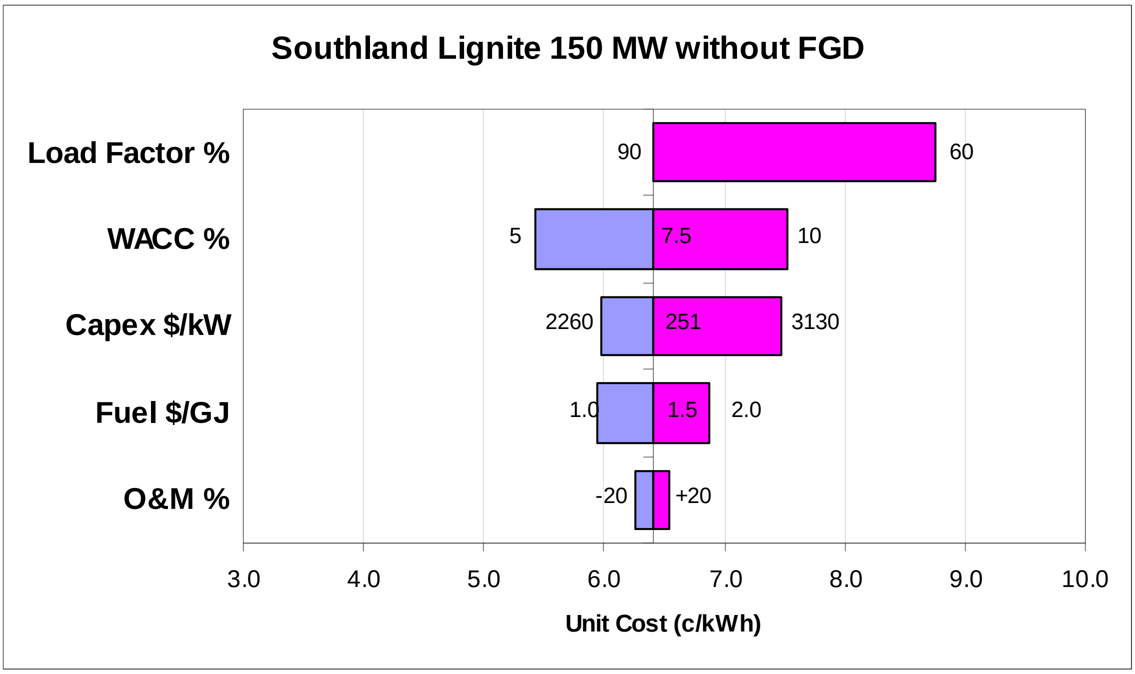


Figure B13: Bituminous Coal without FGD (500 MW)

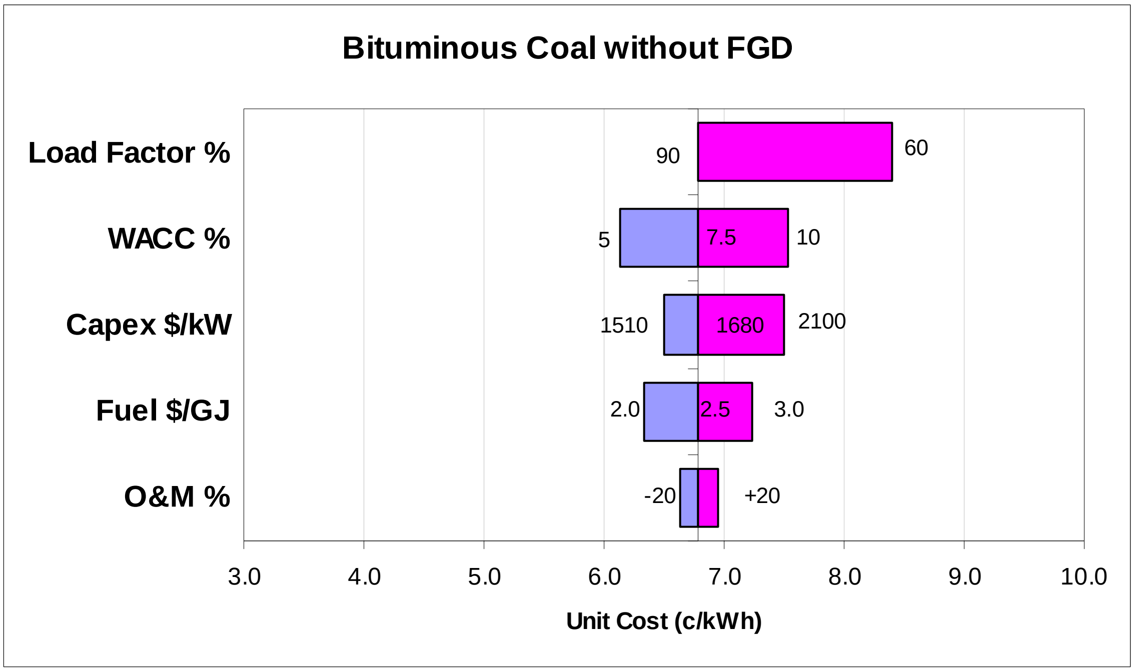


Figure B14: North Island Sub-bituminous Coal without FGD (500 MW)

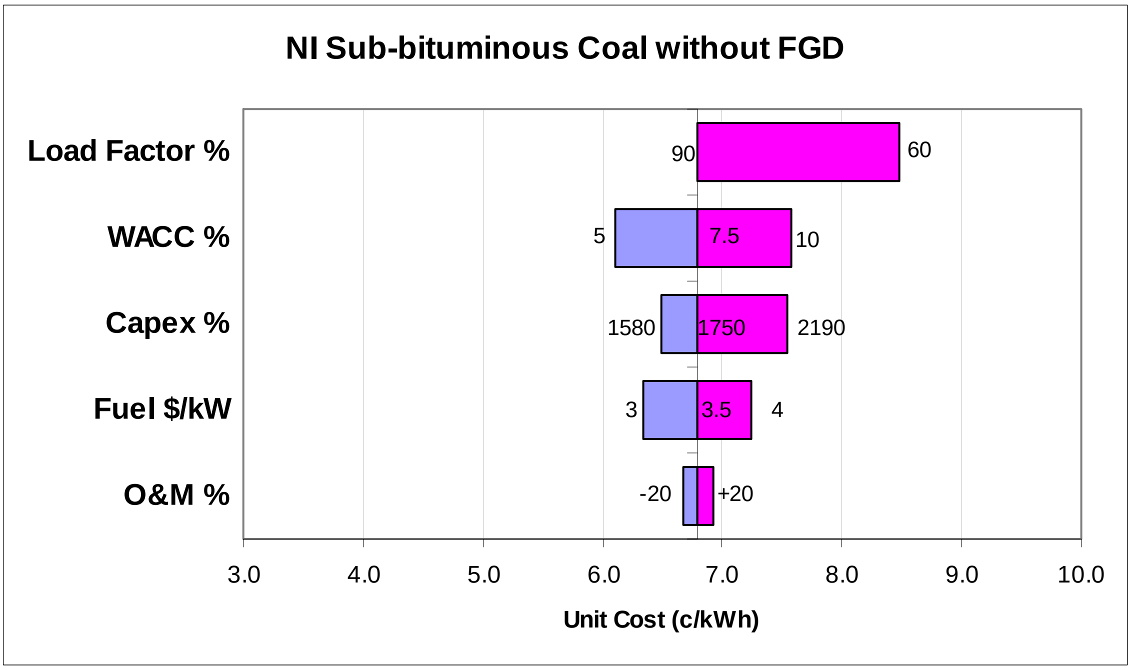


Figure B15: West Coast (SI) Bituminous Coal without FGD (150 MW)

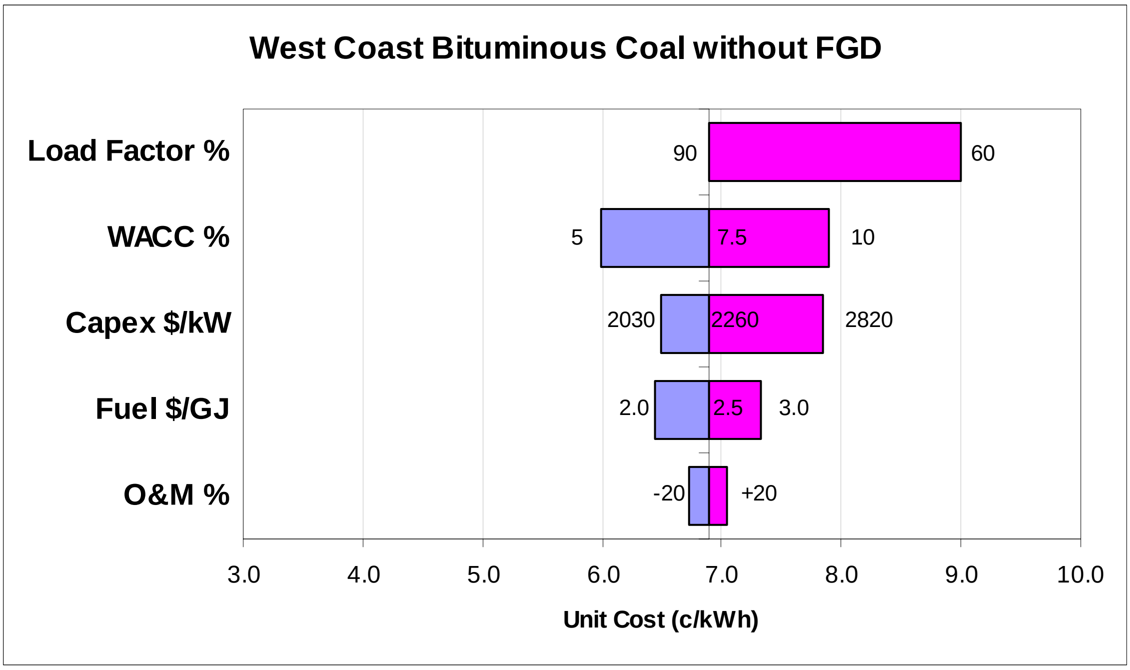
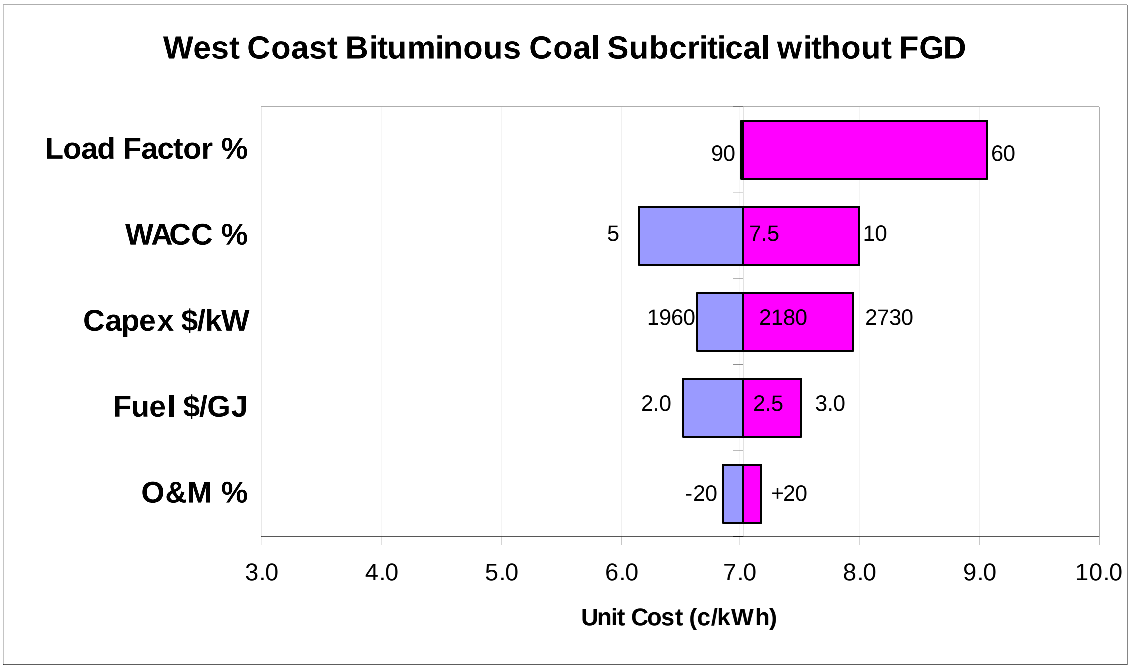


Figure B16: West Coast (SI) Bituminous Coal, Subcritical plant without FGD (150 MW)



B.1 Comment

Coal fired plant exhibits a wider range of unit costs for the range of sensitivities than does gas fired plant.

Load factor and capex are the most sensitive inputs for coal fired plant, whereas fuel costs, followed by load factor, are the most sensitive for gas fired plant.

Appendix C: Future Unit Costs

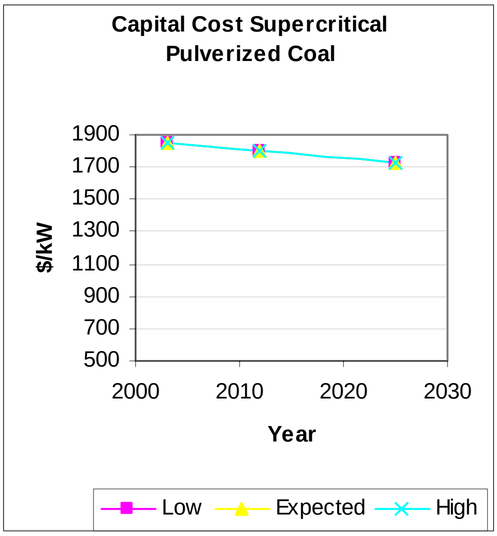
Tables C1 to C5 give estimated capital costs and efficiencies for 2003, 2012 and 2025 for the various technologies. Tables C6 to C17 give estimated unit electricity costs for 2003, 2012 and 2025. In these tables the expected capital costs and efficiencies from Tables C1 to C5 have been used, but the fuel and O&M costs used are the same as those for the 2003 cases.

It should be noted that efficiencies have been given to one decimal place, not to indicate that degree of precision, but to differentiate between the values of various scenarios and years.

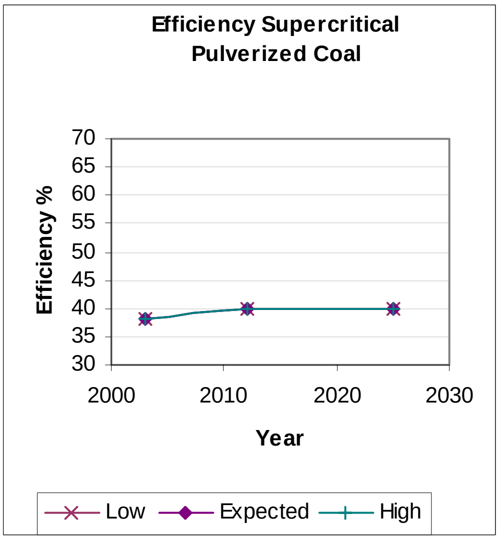
Table C1: Supercritical Pulverized Coal

	Capital Cost $/kW			Efficiency %		
	Technology Uptake			Technology Uptake		
Year	Low	Expected	High	Low	Expected	High
2003	1850	1850	1850	38.3	38.3	38.3
2012	1800	1800	1800	39.9	39.9	39.9
2025	1730	1730	1730	40.1	40.1	40.1

Figure C1: Supercritical Pulverized Coal showing (a) Capital Cost and (b) Efficiency



(a)

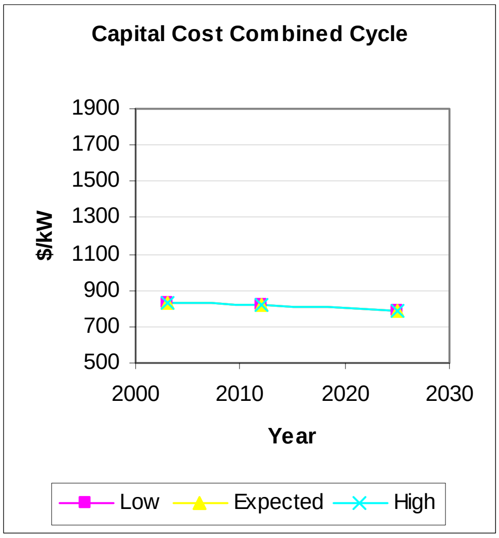


(b)

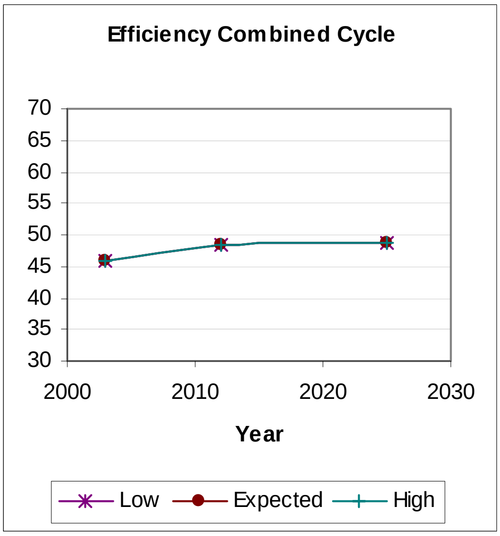
Table C2: Combined Cycle Gas Turbine

	Capital Cost $/kW			Efficiency %		
	Technology Uptake			Technology Uptake		
Year	Low	Expected	High	Low	Expected	High
2003	830	830	830	45.8	45.8	45.8
2012	820	820	820	48.5	48.5	48.5
2025	790	790	790	48.7	48.7	48.7

Figure C2: Combined Cycle Gas Turbine showing (a) Capital Cost and (b) Efficiency



(a)

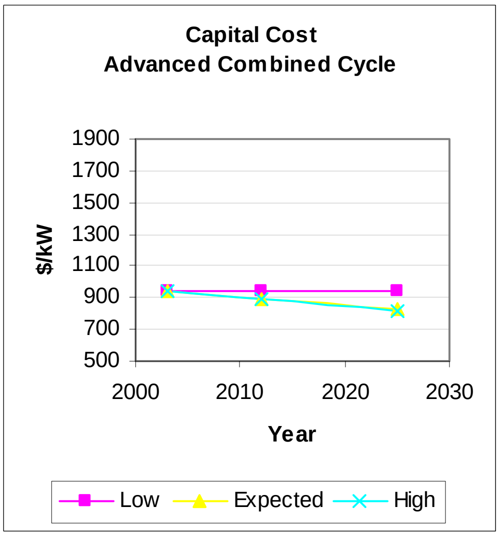


(b)

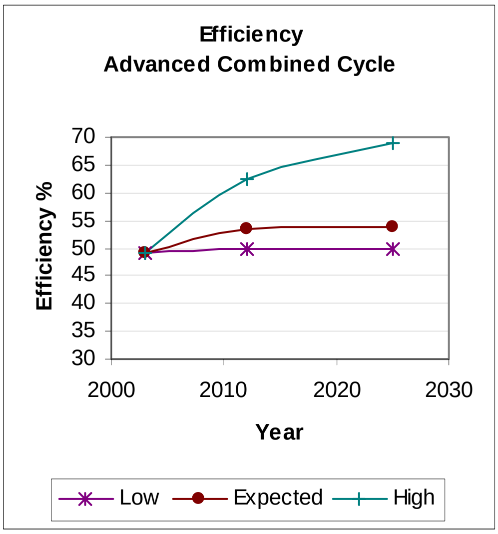
Table C3: Combined Cycle Advanced Gas Turbine

	Capital Cost $/kW			Efficiency %		
	Technology Uptake			Technology Uptake		
Year	**Low**	**Expected**	**High**	**Low**	**Expected**	**High**
2003	940	940	940	49.2	49.2	49.2
2012	940	900	890	49.8	53.4	62.3
2025	940	830	810	49.8	53.7	68.8

Figure C3: Combined Cycle Advanced Gas Turbine showing (a) Capital Cost and (b) Efficiency



(a)

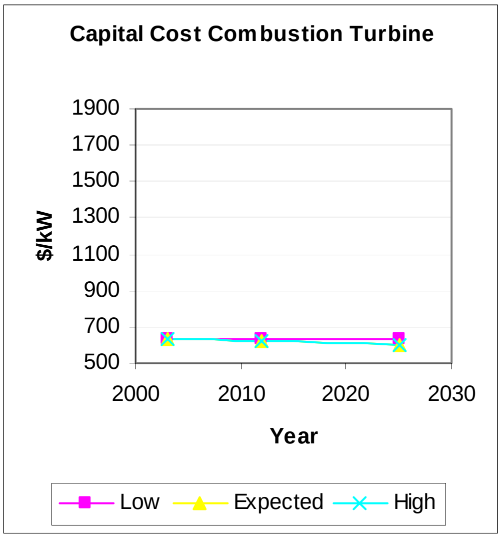


(b)

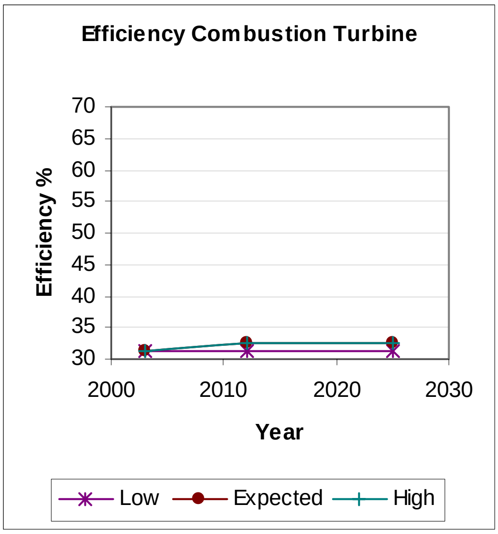
Table C4: Open Cycle Gas Turbine

	Capital Cost $/kW			Efficiency %		
	Technology Uptake			Technology Uptake		
Year	Low	Expected	High	Low	Expected	High
2003	630	630	630	31.4	31.4	31.4
2012	630	620	620	31.4	32.7	32.7
2025	630	600	600	31.4	32.7	32.7

Figure C4: Open Cycle Gas Turbine showing (a) Capital Cost and (b) Efficiency



(a)

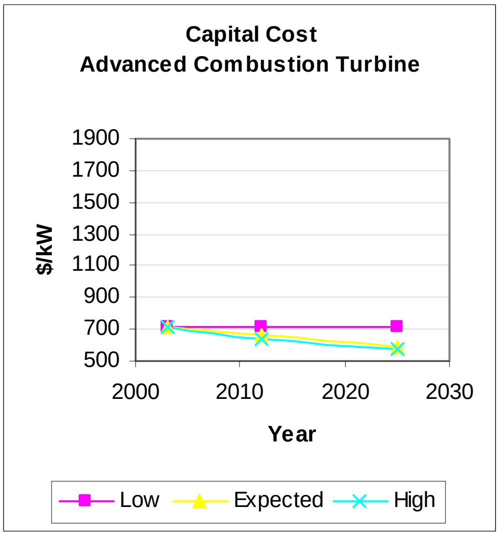


(b)

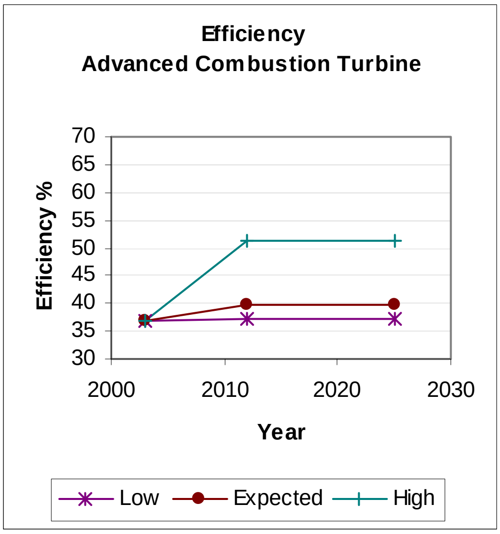
Table C5: Open Cycle Advanced Gas Turbine

	Capital Cost $/kW			Efficiency %		
	Technology Uptake			Technology Uptake		
Year	Low	Expected	High	Low	Expected	High
2003	720	720	20	36.7	36.7	36.7
2012	710	660	640	37.2	39.9	51.2
2025	710	590	570	37.2	39.9	51.2

Figure C5: Open Cycle Advanced Gas Turbine showing (a) Capital Cost and (b) Efficiency



(a)



(b)

Table C6: 2003 Electricity Costs (5% discount rate, 20 year life, $5.00/GJ gas, $3.50/GJ bituminous coal, 90% load factor)

Technology	MW	Cost c/kWh				
		Capital	Fuel	O & M	Other	Total
Combined cycle advanced gas turbine	400	1.0	3.4	0.4	0.2	4.9
Combined cycle gas turbine	250	0.9	3.9	0.4	0.2	5.3
Open cycle advanced gas turbine	230	0.7	4.9	0.5	0.1	6.2
Bituminous supercritical with FGD	160	2.0	3.3	0.9	0.4	6.6
Open cycle gas turbine	500	0.6	5.5	0.6	0.1	6.8

Table C7: 2003 Electricity Costs (5% discount rate, 20 year life, $6.00/GJ gas, $4.00/GJ bituminous coal, 90% load factor)

Technology	MW	Cost c/kWh				
		Capital	Fuel	O & M	Other	Total
Combined cycle advanced gas turbine	400	1.0	4.0	0.4	0.2	5.6
Combined cycle gas turbine	250	0.9	4.6	0.4	0.2	6.1
Bituminous supercritical with FGD	230	2.0	3.8	0.9	0.4	7.1
Open cycle advanced gas turbine	160	0.7	5.9	0.5	0.1	7.2
Open cycle gas turbine	500	0.6	6.6	0.6	0.1	7.9

Table C8: 2003 Electricity Costs (10% discount rate, 20 year life, $5.00/GJ gas, $3.50/GJ bituminous coal, 90% load factor)

Technology	MW	Cost c/kWh				
		Capital	Fuel	O & M	Other	Total
Combined cycle advanced gas turbine	400	1.4	3.4	0.4	0.4	5.6
Combined cycle gas turbine	250	1.3	3.9	0.4	0.3	5.9
Open cycle advanced gas turbine	230	1.0	4.9	0.5	0.3	6.6
Open cycle gas turbine	160	0.9	5.5	0.6	0.2	7.2
Bituminous supercritical with FGD	500	3.1	3.3	0.9	0.9	8.2

Table C9: 2003 Electricity Costs (10% discount rate, 20 year life, $6.00/GJ gas, $4.00/GJ bituminous coal, 90% load factor)

Technology	MW	Cost c/kWh				
		Capital	Fuel	O & M	Other	Total
Combined cycle advanced gas turbine	400	1.4	4.0	0.4	0.4	6.2
Combined cycle gas turbine	250	1.3	4.6	0.4	0.3	6.6
Open cycle advanced gas turbine	230	1.0	5.9	0.5	0.3	7.6
Open cycle gas turbine	160	0.9	6.6	0.6	0.2	8.3
Bituminous supercritical with FGD	500	3.1	3.8	0.9	0.9	8.6

Table C10: 2012 Electricity Costs (5% discount rate, 20 year life, $5.00/GJ gas, $3.50/GJ bituminous coal, 90% load factor)

Technology	MW	Cost c/kWh				
		Capital	Fuel	O & M	Other	Total
Combined cycle advanced gas turbine	400	0.9	3.4	0.4	0.2	4.8
Combined cycle gas turbine	250	0.8	3.7	0.4	0.2	5.1
Open cycle advanced gas turbine	230	0.7	4.5	0.5	0.1	5.8
Bituminous supercritical with FGD	160	1.9	3.2	0.9	0.4	6.4
Open cycle gas turbine	500	0.6	5.5	0.6	0.1	6.8

Table C11: 2012 Electricity Costs (5% discount rate, 20 year life, $6.00/GJ gas, $4.00/GJ bituminous coal, 90% load factor)

Technology	MW	Cost c/kWh				
		Capital	Fuel	O & M	Other	Total
Combined cycle advanced gas turbine	400	0.9	4.0	0.4	0.2	5.5
Combined cycle gas turbine	250	0.8	4.5	0.4	0.2	5.9
Open cycle advanced gas turbine	230	0.7	5.4	0.5	0.1	6.7
Bituminous supercritical with FGD	160	1.9	3.6	0.9	0.4	6.9
Open cycle gas turbine	500	0.6	6.6	0.6	0.1	7.9

Table C12: 2012 Electricity Costs (10% discount rate, 20 year life, $5.00/GJ gas, $3.50/GJ bituminous coal, 90% load factor)

Technology	MW	Cost c/kWh				
		Capital	Fuel	O & M	Other	Total
Combined cycle advanced gas turbine	400	1.4	3.4	0.4	0.4	5.5
Combined cycle gas turbine	250	1.2	3.7	0.4	0.3	5.7
Open cycle advanced gas turbine	230	0.9	4.5	0.5	0.2	6.1
Open cycle gas turbine	160	0.9	5.5	0.6	0.2	7.2
Bituminous supercritical with FGD	500	3.0	3.2	0.9	0.9	7.9

Table C13: 2012 Electricity Costs (10% discount rate, 20 year life, $6.00/GJ gas, $4.00/GJ bituminous coal, 90% load factor)

Technology	MW	Cost c/kWh				
		Capital	Fuel	O & M	Other	Total
Combined cycle advanced gas turbine	400	1.4	4.0	0.4	0.4	6.1
Combined cycle gas turbine	250	1.2	4.5	0.4	0.3	6.5
Open cycle advanced gas turbine	230	0.9	5.4	0.5	0.2	7.0
Open cycle gas turbine	160	0.9	6.6	0.6	0.2	8.3
Bituminous supercritical with FGD	500	3.0	3.6	0.9	0.9	8.4

Table C14: 2025 Electricity Costs (5% discount rate, 20 year life, $5.00/GJ gas, $3.50/GJ bituminous coal, 90% load factor)

Technology	MW	Cost c/kWh				
		Capital	Fuel	O & M	Other	Total
Combined cycle advanced gas turbine	400	0.9	3.4	0.4	0.2	4.8
Combined cycle gas turbine	250	0.8	3.7	0.4	0.2	5.1
Open cycle advanced gas turbine	230	0.6	4.5	0.5	0.1	5.7
Bituminous supercritical with FGD	160	1.9	3.2	0.9	0.4	6.3
Open cycle gas turbine	500	0.6	5.5	0.6	0.1	6.8

Table C15: 2025 Electricity Costs (5% discount rate, 20 year life, $6.00/GJ gas, $4.00/GJ bituminous coal, 90% load factor)

Technology	MW	Cost c/kWh				
		Capital	Fuel	O & M	Other	Total
Combined cycle advanced gas turbine	400	0.9	4.0	0.4	0.2	5.4
Combined cycle gas turbine	250	0.8	4.4	0.4	0.2	5.8
Open cycle advanced gas turbine	230	0.6	5.4	0.5	0.1	6.6
Bituminous supercritical with FGD	160	1.9	3.6	0.9	0.4	6.8
Open cycle gas turbine	500	0.6	6.6	0.6	0.1	7.9

Table C16: 2025 Electricity Costs (10% discount rate, 20 year life, $5.00/GJ gas, $3.50/GJ bituminous coal, 90% load factor)

Technology	MW	Cost c/kWh				
		Capital	Fuel	O & M	Other	Total
Combined cycle advanced gas turbine	400	1.3	3.4	0.4	0.3	5.3
Combined cycle gas turbine	250	1.2	3.7	0.4	0.3	5.6
Open cycle advanced gas turbine	230	0.8	4.5	0.5	0.2	6.0
Open cycle gas turbine	160	0.8	5.5	0.6	0.2	7.2
Bituminous supercritical with FGD	500	2.9	3.2	0.9	0.9	7.8

Table C17: 2025 Electricity Costs (10% discount rate, 20 year life, $6.00/GJ gas, $4.00/GJ bituminous coal, 90% load factor)

Technology	MW	Cost c/kWh				
		Capital	Fuel	O & M	Other	Total
Combined cycle advanced gas turbine	400	1.3	4.0	0.4	0.3	6.0
Combined cycle gas turbine	250	1.2	4.4	0.4	0.3	6.4
Open cycle advanced gas turbine	230	0.8	5.4	0.5	0.2	6.9
Bituminous supercritical with FGD	160	2.9	3.6	0.9	0.9	8.2
Open cycle gas turbine	500	0.8	6.6	0.6	0.2	8.3

Appendix D: Cost Adjustment Procedure

D.1 Capital Cost Estimation

Much of the plant is considered to have to be sourced overseas. Also, some of the cost estimates were based on overseas information. Where it was necessary to use exchange rates, the following rates were used: $NZ 1.00 = US$ 0.60, $NZ 1.00 = Euro 0.50, and $NZ 1.00 = £ 0.33.

D.2 Operations and Maintenance Cost Estimation

The procedure was the same as for the capital cost estimation.

Appendix E: Adjustment of Capital Costs for Unit Size

The specific capital costs generally apply to plant that is close to the size of plant that has been quoted. Scaling factors are used to estimate the specific cost of plant of a different size. Capital costs tend to obey power laws in terms of relation to size.

An estimate of a different size of plant can be found by applying the following formula

$$C = C_{known} \text{ x } (S_{known} / S)^n \text{ in \$/kW}$$

Where C is the unknown cost in $/kW

C_{known} is the known cost in $/kW

S_{known} is the known size

S is the size for which the cost is to be calculated

n is the scaling factor

The following table E1 gives approximate capital cost scaling factors over a limited range, say ± 50%.

Table E1: Capital Cost Scaling Factors

Technology	Scaling Factor "n"
Simple cycle gas turbine	0.23
Combined cycle gas turbine (CCGT)	0.3
Pulverised coal fuel	0.25

Appendix F: Technology Lead Times

Time has a cost, so the time it takes from project conception to commercial operation has a significant effect on the viability of any electricity generating plant project. In this report only costs that are incurred from the beginning of design and construction are included in the electricity unit costs for the different technologies.

F.1 Project Stages

All projects, no matter what the technology, follow a similar process but the timings do differ. Three main stages in the process can be identified.

The first stage consists of a large number of activities that include: scoping, investigation, feasibility studies, consultation, conceptual design and a decision made to apply for resource consents.

The second stage is the preparation of the appropriate documents, further consultation and the application for resource consents and perhaps dealing with appeals. Once resource consents are granted and the outcome of any appeals determined the developer can then decide whether or not to proceed; this is when the third stage begins. This stage includes finalising the detailed design, procurement, construction and commissioning.

Usually infrastructure issues such as electricity transmission, gas transmission, and coal supply and transport also need to be considered. An adequate water supply is also required.

F.1.1 Stage 1, Pre-Consent Studies and Consultation

This stage is primarily concerned with resource, community and environmental issues.

Fuel and water resources that are required need to be defined, investigated and secured. If these are readily available then this may not be a large issue but changes in land use to fit a project's requirements may be. The necessary land also needs to be secured.

Running in parallel with these studies it will be necessary to undertake pre-feasibility studies of options (these having been identified earlier in scoping studies) and a preliminary environmental reconnaissance followed by feasibility studies. The latter stage generally involves local and regional councils and community interest groups.

Where an extension of a mine or new mine is required this could be done in parallel with the power station development. In this case, all three project stages would need to be gone through for the mine. Timing would need to ensure that the mining consents were obtained before the commitment to proceed with stage 3 of the power station development.

The preferred power station option is selected by consideration of all the factors by the developer, after which information on this option can be released for public consultation. Some detail design and detailed investigations can be carried out often involving the relevant community groups. Following this, sufficient information should be available to proceed to the next stage.

F.1.2 Stage 2, Application for Consents and Approvals

This stage involves preparation of all the necessary documentation for resource consents and other required approvals, including an assessment of the environmental effects and resolution of adverse effects, and submitting them to the appropriate authorities.

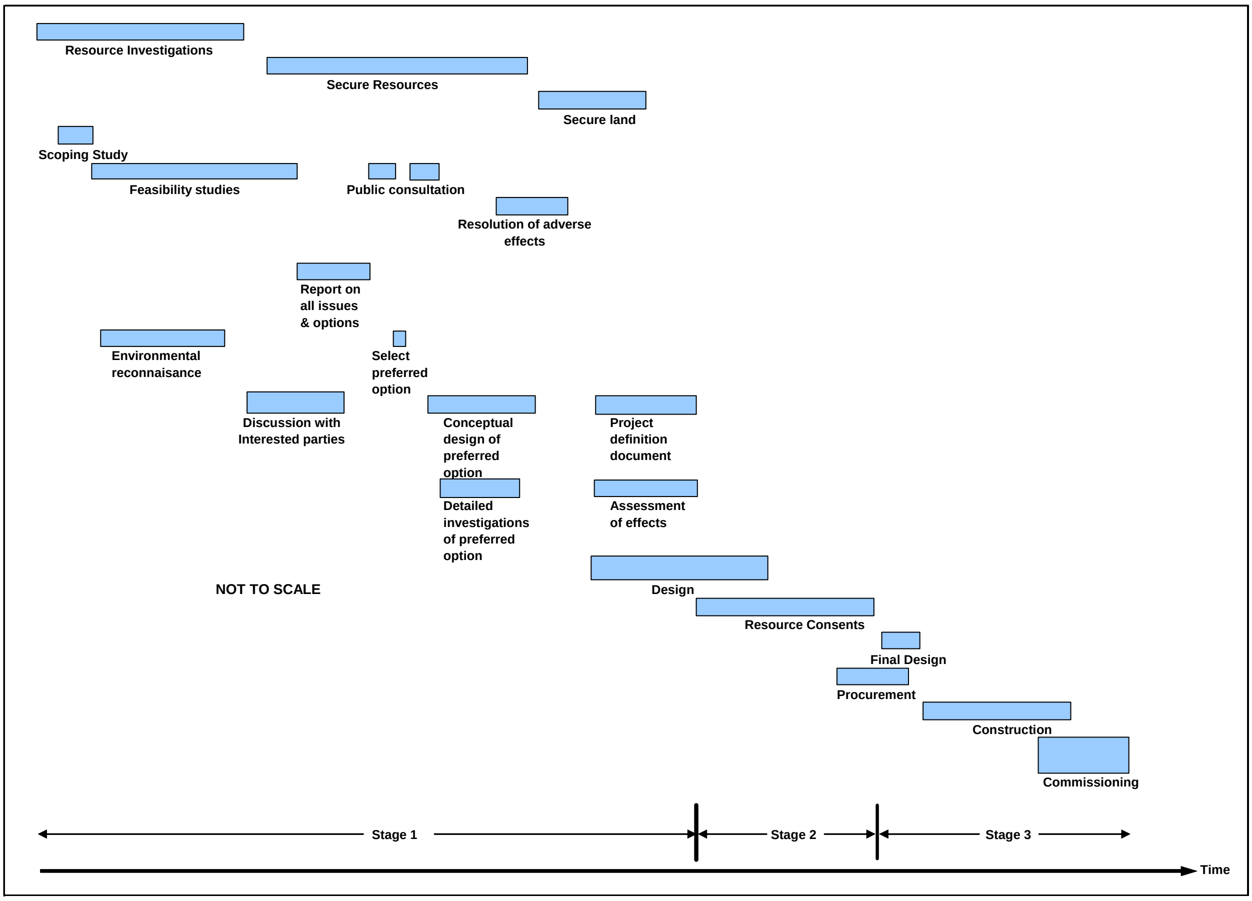
Consideration of the resource consent application needs to follow the process and timing set out in statute. Additional time may be needed to supply more information if requested by the consent authorities and to deal with appeals. Familiarity and experience by the consent authorities in dealing with energy matters may reduce the time taken.

F.1.3 Stage 3, Design, Build and Commission

Once consents and approvals have been obtained final design, procurement, construction and commissioning can follow. Depending upon how the process has been managed, many activities can be run in parallel so that once approvals are given construction may start straight away.

The whole process is depicted in Figure F1

Figure F1: General Investigations Programme



F.2 Infrastructure

Some general comments can be made about infrastructure issues such as, electricity transmission, gas transmission, coal supply and transport, water supply and waste disposal, but most are site specific.

F.2.1 Gas Fuelled Plant

For gas fuelled plant it would be expected that it would be situated within a reasonable proximity to existing gas supply line and electricity transmission system that have sufficient capacity.

F.2.2 Coal Fuelled Plant

Coal fired plant has a more complex set of issues.

Should Southland and the West Coast be considered it would be likely that a power station would be situated close to the mine so transport issues should be small. Electricity transmission appears to be the major infrastructure issue and could be the limiting factor on the size of the plant.

For coal plant situated in the northern Waikato region, coal may be sourced from several mines so coal transport would have to be addressed. Coal could come from existing and new mines. Electricity transmission may be assisted by the proposed Transpower upgrades from Huntly to Otahuhu expected to be commissioned in June 2005, noting that a more significant upgrade is targeted for 2010.

Should a coal fired plant in the Marsden Point region be considered, it is likely that it would be situated close to the port so the coal transport route would be short. Electricity transmission should not be an infrastructural issue for anything up to a 500 MW plant.

If coal is imported or is transported over a significant distance, then a number of territorial authorities may be involved in consenting. This should not add to the overall time for consenting, but it would add to the resource needed for preparing consent applications and for progressing them.

F.3 Gas Fuelled Electricity Generation

Gas turbine based projects lend themselves to modular construction techniques which lead to more standardised designs and shorter construction periods than for coal based ones.

F.3.1 Open Cycle Gas Turbines

These are the simplest of the technologies considered, available in modules and have the shortest project times. Major issues are likely to include air discharges, noise (particularly in an urban environment), and perhaps water supply and waste disposal.

F.3.2 Combined Cycle Gas Turbines

These are more complex than open cycle gas turbines but are generally still modular in nature. In this case, the gas turbine, heat recovery steam generator (HRSG), and steam turbine all need to be matched. Cooling requirements are more complex.

Major issues are similar to the open cycle gas turbine but in addition there is a requirement for more or larger cooling towers, and the effects of spray drift, the visual plume, and effluent discharge need to be addressed.

F.4 Coal Fuelled Electricity Generation

Coal plant designs can be standardised but require more customisation, principally to deal with the differing characteristics of the coal being fired. Because of the complexity and extra plant needed, a coal based project takes a lot longer than a gas based one. An extension to a mine or a new mine and coal transport may also be part of an overall project which would add to the complexity and issues to be addressed, particularly if several consenting authorities are involved. This part of the project would run in parallel with the power plant part. The power plant would generally be expected to be on the critical path, so the mine should not add to the time to commissioning. However in some cases a new mine may extend the overall project time.

Coal has the same major issues that are associated with operating combined cycle gas turbine plant (water supply, noise, air discharges), but also there may be coal mining issues (dust, noise, effluent disposal and land remediation), coal transport and storage issues (dust, noise), and additional issues stemming from the operation of the plant (fugitive dust emissions, ash disposal; and effluent from flue gas desulphurisation may also need to be addressed).

If coal is imported, then coal unloading and storage issues at the port may need to be addressed as well.

F.5 Project Duration

The times for each stage for key different technologies are set out in Table F1. With respect to gas turbines, times for advanced open cycle plant should be the same as for standard open cycle plant, and times for advanced combined cycle plant should similarly be the same as for standard combined cycle plant.

With respect to coal plant, times for subcritical and supercritical plant should be the same. Also, whether plant is for lignite, sub-bituminous or bituminous coal should not have any significant effect on times, and whether or not flue gas desulphurisation (FGD) is installed should not make any difference.

The times are approximate and indicative only. A number of activities can run in parallel particularly in the design area so the times shown are those that add to the overall project time. Delivery from vendors can vary depending upon demand for their equipment at the time. How urgently the buyer requires the plant can also affect delivery times. The greatest uncertainty in the timing is with stage 2, the consent and approval stage.

Table F1: Project Times

Technology	Duration (Months)								
	Total			Pre-Consent Activities		Consents and Approvals *		Constn and Comming **	
	Likely	Min	Max	Min	Max	Min	Max	Min	Max
Open cycle gas turbine	33	23	41	5	6	6	17	12	18
Combined cycle gas turbine	57	38	77	6	24	6	17	26	36
Coal plant supercritical with FGD	79	60	109	12	36	12	22	36	51

* Included in these times are a 16 week "float" to provide for additional information, mediation or pre-hearing conference or other events and 26 weeks for appeals. For coal an additional 22 weeks has been added for an appeal.

** These times are used in the calculation of electricity unit cost. Costs however include all those incurred from the design and procurement stages onwards.

From Table F1 it can be seen that an open cycle gas turbine may take over two and a half years from the initial idea to commercial operation, a combined cycle over four and a half years and over six and a half years for a coal fired station. These estimated times are those for a greenfield site and a project that runs reasonably smoothly. Reductions in time may be possible where there are existing facilities, but such reductions are not likely to be significant.

Appendix G: Transmission Losses and Costs

Table G1 below may assist in giving some estimate of the cost associated with transmission losses. This table should be used with care as:

- It is very indicative, suggesting an order of magnitude, rather than a precise figure.
- These losses, and the cost of these losses, must be considered against the losses and their costs that will occur when generation is located close to demand.
- No comment on the extent to which the marginal loses will apply, nor the periods of time they will apply to, is provided. Maximum marginal losses will likely only occur for very short periods of time, and these may coincide with maximum south-north power transfer when prices are not likely to be at their highest.
- Losses will be affected (generally adversely) by increases in load carried by the transmission system.
- Losses will be significantly reduced as various sections of the transmission system are physically upgraded with larger conductors or higher operating voltage levels (or both).

Table G1: Transmission Losses

Transmission Losses						
Electricity price at grid injection point (GIP) in Southland	5.7 c/kWh					
Average loss	5.5%	6.5%				
Marginal losses						
South Island			5%	5%	5%	10%
HVDC			5%	5%	10%	15%
North Island			5%	10%	20%	30%
Reduction in energy delivered (losses)	5.5%	6.5%	15%	20%	35%	55%
Cost of losses at Auckland GXP price (c/kWh)	**0.31**	**0.37**	**0.86**	**1.14**	**2.00**	**3.14**

Note: the losses in the above table are developed from the following information in Transpower's submissions to the 2000 Electricity Inquiry (footnote 33, Volume II: Wholesale Market):

Average transmission losses over the North and South Island networks, including the HVDC link, tend to vary between 5.5 and 6.5 %, the magnitude of the marginal losses can at times be high, reaching 5–10% over the South Island, 10-15% over the HVDC and 20-30% over the North Island.

Appendix H: Subcritical and Supercritical Boiler

The following extract taken from an article by Ingo Paul in Energy Issues No 19 April 1999 published by the World Bank http://www.worldbank.org/energy/pdfs/EnergyIssues_19.pdf briefly describes the difference between a subcritical and a supercritical boiler.

"Supercritical" is a thermodynamic expression describing the state of a substance where there is no clear distinction between the liquid and the gaseous phase (i.e. they are a homogenous fluid). Water reaches this state at a pressure above 22.1 megapascals (MPa)

The "efficiency" of the thermodynamic process of a coal fired power (sic) describes how much of the energy fed into the cycle is converted into electrical energy. The greater the output of electrical energy for a given amount of energy input, the higher the efficiency. If the energy input to the cycle is kept constant, the output can be increased by selecting elevated pressures and temperatures for the water-steam cycle.

Up to an operating pressure of around 19 MPa in the evaporator part of the boiler, the cycle is sub-critical. This means, that there is a non-homogeneous mixture of water and steam in the evaporator part of the boiler. In this case a drum-type boiler is used because the steam needs to be separated from water in the drum of the boiler before it is superheated and led into the turbine. Above an operating pressure of 22.1 MPa in the evaporator part of the boiler, the cycle is supercritical. The cycle medium is a single phase fluid with homogeneous properties and there is no need to separate steam from water in a drum. Once-through boilers are therefore used in supercritical cycles.

Appendix I: Bibliography

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