Regulatory Test Evaluation of a Major SWIS Network Reinforcement

South West to Perth 330 kV transmission line - addendum

Prepared for Western Power

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ACIL Tasman

Economics Policy Strategy

Reliance and Disclaimer

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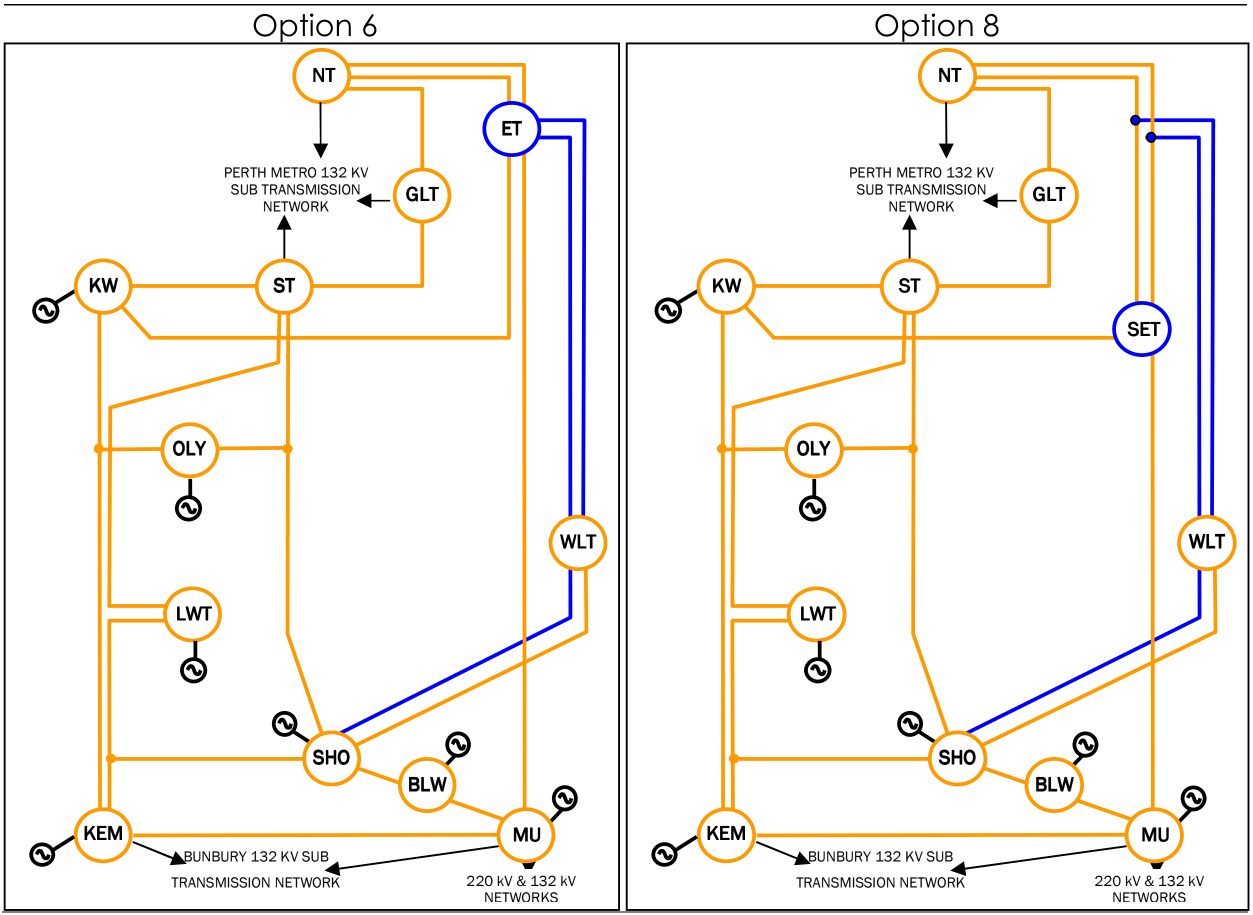
Boxes, charts, figures and tables

Addendum

This report was originally produced in September 2007 in preparation for public consultation concerning the construction of a new 330 kV transmission line connecting South West generation to the Perth metropolitan area.

In response to extensive public consultation, Western Power has developed an alternative option, which is referred to as Option 8 throughout this revised report. Subsequent to the public consultation, Western Power determined that there would not be adequate time to complete the recommended option (Option 6). Hence, Option 8 has been developed to replace Option 6. The main difference between these two options is the relocation of the new Eastern Terminal (ET) to the south and once constructed will be referred to as the South East Terminal (SET).

Addendum Figure 1 **Network diagrams showing the difference between Option 6 and Option 8**



Data source: Western Power

The net present cost of both Option 6 and Option 8 are provided in Addendum Table 1. As indicated, Option 8 is more costly than Option 6. Comparing the difference between the high and low estimates for each option, it appears that the realised cost could vary by as much as 15 per cent either up or down. Given the size of this variation, the difference between the options, which is estimated to be approximately 2 per cent, appears to be immaterial. Hence, the higher cost of Option 8 does not have a material impact on the expected net benefit to generators, transporters, and consumers.

Addendum Table 1 **Net present cost estimates for Option 6 and Option 8**

Option	Expected ($M)	High ($M)	Low ($M)	Variance ($M)
6	138.2	139.1	118.7	20.4
8	141.5	143.1	121.5	21.6

Source: Western Power

We also take this opportunity to note several other developments that have taken place since the report was originally written. First, the Commonwealth Government has released further details of the Emissions Trading Scheme referred to in the original report and now called the Carbon Pollution Reduction Scheme (CPRS). Information concerning the CPRS suggests a carbon emissions price within the range modelled in this report. This implies that our original assumptions remain valid. Second, we note that domestic gas prices have actually increased substantially above our original assumptions. Whilst future gas prices remain uncertain, it would appear that long-run domestic gas prices may remain be higher than we originally assumed. This has the effect of increasing the net benefit of the proposed network reinforcement.

Executive summary

Western Power advises that the existing South West to Perth transmission lines are near full capacity and cannot support further load

Western Power commissioned ACIL Tasman to assist in an economic evaluation of its proposal to establish a new double circuit 330kV transmission line from the South West region to Perth. The principal reason for proposing the new transmission line is that the existing South West to Perth transmission lines are near full capacity and cannot support future load growth. This report complements the technical evaluation conducted by Sinclair Knight Merz (SKM). Their evaluation supports Western Power's assessment.[1]

This evaluation applies the Regulatory Test, which is concerned with determining whether the proposed transmission line maximises net benefit as defined in Chapter 9 of the *Electricity Networks Access Code 2004* ("the Code").

In conducting this evaluation, ACIL Tasman has used both quantitative and qualitative methods to analyse the options available. The main component of this analysis is based on scenarios developed using ACIL Tasman's *PowerMark WA* model. This enables a rigorous and internally consistent way of assessing the size of the net benefits that are likely to be derived from upgrading the South West transmission line under a wide range of alternative market scenarios.

The evaluation is based on two generation scenarios and seven market scenarios

The decision whether or not to install a new transmission line gives rise to two distinct generation portfolios. Without the new transmission line, it is likely that combined cycle gas turbines will account for a substantially larger share of the generation portfolio than with the new transmission line. The question is: which portfolio maximises net benefit?

In answering this question, ACIL Tasman developed seven market scenarios as follows:

1. Business as usual
2. Emission trading capped at $30/tCO2e
3. Emissions trading capped at $20/tCO2e
4. Low forecast growth with a $30 emissions trading cap
5. High gas price with $30 emissions trading cap
6. High gas price with $20 emissions trading cap
7. 2007 load forecast with $20/tCO2e emissions trading cap

[1] Sinclair Knight Merz, *Proposed New Large Network Asset for Reinforcement of the Electricity Supply to the Perth Metropolitan Area, Due Diligence Review of 330KV Augmentation Studies*, V1.1, 4 September 2007

As is implied by the number of scenarios, there are multiple possible futures. Which scenario materialises largely depends on the course of government policy and the energy choices that the Western Australia community make. This report is a frank assessment of the implications of the possible choices.

In every scenario consumers benefit from the proposed new South West to Perth transmission line

The results show that under a business as usual scenario, the proposed new transmission line maximises net benefits and therefore satisfies the Regulatory Test. The results under the alternative scenarios indicate that the difference in net benefits between the generation portfolios are too close to say that one portfolio definitely offers larger net benefit than the other.

Given these results, ACIL Tasman considered the non-network alternatives and qualitative factors relevant to the evaluation. With regard to the non-network alternatives, demand side management is unlikely to provide significant benefit. Further reactive power support is also unlikely to materially alleviate the situation. Western Power advises that by 2011 the existing South West to Perth transmission lines will be operating with little spare capacity. From a safety and reliability point of view, some form of transmission augmentation is unavoidable.

With regard to increased electricity generation within the Perth metropolitan area, there are several generation sites available, such as Kwinana and Neerabup. However, Kwinana is constrained. Neerabup appears to be a viable site for new generation, but will require network reinforcement.

Deliberately delaying upgrading the transmission line is a risky option

Given the possibility of significant new electricity generation capacity locating in the Perth metropolitan area, it is necessary to consider the merits of delaying network augmentation. ACIL Tasman believes that capacity payments are sufficient to encourage construction of gas-fired 'peaking' plant. Offsetting this is the current very high price for domestic gas and the risks of delay in obtaining the necessary regulatory approvals. Hence, with the SWIS at or near capacity, it would be risky to deliberately delay network augmentation.

The proposed new South West to Perth transmission line will reduce the impediment to adoption of further alternative electricity generation

Another issue to consider is the value of facilitating an increased share of renewable and low carbon emission electricity generation. The tendency for alternative energy such as biomass and wind power to be located at some distance from major load centres places these generation alternatives at a disadvantage. To the extent that the South West augmentation provides a positive investment signal for the development of alternative energy, the South West augmentation offers benefit.

Finally, ACIL Tasman considered forecast risk. We note the IMO's 2007 Statement of Opportunities Report increase of 167MW of reserve capacity and the jump in demand forecast, due largely to 200MW of air conditioner load installed in Western Australia. ACIL Tasman considers it likely that robust economic growth will continue to drive growth in electricity demand. Unless significant energy saving policies are implemented, it would appear, on the balance of probabilities, that there is a greater risk of under-estimating as opposed to over-estimating load growth in a system that is already near full capacity.

In view of all of the issues, ACIL Tasman recommends that Option 8 proceed as this is, on economic and technical grounds, the option that satisfies the Regulatory Test.

1 Introduction

ACIL Tasman has been commissioned by Western Power to assist in an economic evaluation of the compliance of its preferred 330kV electricity transmission upgrade with the requirements of the Western Australian Regulatory Test. The Regulatory Test, which is defined in the Electricity *Networks Access Code 2004* ("the Code"), is an assessment of whether a proposed major augmentation to a covered network maximises net benefit after considering a range of alternative options.

Under the Code, the net benefit applies to those who generate, transport and consume electricity in the covered network and any interconnected system. Moreover, the evaluation must consider all reasonable alternative options, including the likelihood of each alternative option proceeding.

Western Power has provided a range of options which are considered by Western Power to be reasonable. There are a considerable number of options that span both network and non-network augmentation. The non-network options considered are: demand side management; Perth metropolitan generation; and reactive support from existing generators. Note that the technical options are taken by ACIL Tasman as given. For a technical evaluation of the options see Sinclair Knight Merz, *Proposed New Large Network Asset for Reinforcement of the Electricity Supply to the Perth Metropolitan Area, Due Diligence Review of 330KV Augmentation Studies* V1.1, 4 September 2007.

The network options considered are variations on two main options for providing an additional transmission line tie between the generation sources and the main load centre in Perth. There are seven network options, four being variations to Option 1 that enable deferral of Option 1 for two years. From a technical perspective, Option 6 is Western Power Network's preferred option. Option 7 is a variation of Option 6, enabling deferral for two years.

In this evaluation, we have considered the full range of options using both quantitative and qualitative methods. We have also considered the need for augmentation as well as the likely impact that carbon emission abatement policies currently under consideration (such as national emissions trading from 2010) may have on mitigating that need.

The complexity of this evaluation has required ACIL Tasman to develop a scenario-based modelling approach. Specifically, we have developed an optimisation model that uses linear programming techniques. The main advantages of this approach are: the ability to ensure internal consistency; and to simultaneously consider a wide-range of variations on the discrete options initially considered by Western Power.

2 Perth electricity outlook

2.1 Electricity demand in the Perth region

Maximum electricity demand in the South West Interconnected System (SWIS) is projected to be growing at an underlying annual average of around 3.3 per cent through to 2016/17.[2] Corresponding rates for the 'high' and 'low' economic growth scenarios are for underlying growth rates of 3.9 and 2.9 per cent respectively.

Energy demand is growing at slightly lower rates, with a 'best' estimate for underlying annual average growth of around 2.2 per cent per annum through to 2015/16.[3]

The majority of load on the SWIS is located in the Perth and Kwinana regions. In 2006, the peak demands in these two areas accounted for around three quarters of the total SWIS demand. This proportion is expected to rise slightly through to 2011.[4] This rise reflects the expectation that peak demand in the Kwinana region (which accounts for around 8 per cent of total peak demand) will grow more rapidly than other regions in the SWIS – at around 6 per cent per annum on average. Growth in the Perth region, excluding Kwinana, is much closer to the expected growth rate for the SWIS overall.

2.1.1 Projected demand to 2027/28

For this exercise, the existing projections are extrapolated through to 2027/28 – drawing on expectations for natural load growth in the various regions (Table 1). In the:

- 'best' estimate – peak demand is expected to increase to 5,094 MW by 2016/17 at 10 per cent Probability of Exceedence, and then to 6,531 MW by 2027/28.
- 'low' estimate – peak demand is expected to increase to 4,856 MW by 2016/17 at 10 per cent Probability of Exceedence, and then to 6,040 MW by 2027/28.

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2 Independent Market Operator of Western Australia 2007, *2007 Statement of Opportunities*, www.imowa.com.au, pp 23.

3 Independent Market Operator of Western Australia 2007, op. cit., pp 24.

4 Western Power 2007, *Transmission and Distribution Annual Report*, www.westernpower.com.au, pp 31.

The 'best' estimate reflects central estimates for GDP growth averaging 4.2 per cent per annum, while the 'low' estimate reflects expectations of GDP growth averaging 2.9 per cent per annum.[5]

The 'natural' rates of growth on which we base these projections exclude the one-off impact of the Boddington gold mine. The Boddington load is estimated to add around 6 per cent to energy demands from 2008/09 on.

Table 1 **Projected peak demand and energy growth - SWIS**

	Best estimate		Low estimate	
	MW (10% ex.)	GWh	MW (10% ex.)	GWh
2007/08	3800	15878	3767	15597
2008/09	4086	17072	4033	16665
2009/10	4233	17822	4148	17201
2010/11	4361	18173	4258	17447
2011/12	4505	18741	4376	17795
2012/13	4633	19145	4485	18061
2013/14	4746	19417	4581	18223
2014/15	4881	19819	4673	18355
2015/16	4985	20075	4767	18553
2016/17	5094	20437	4856	18725
2017/18	5251	20773	4986	18911
2018/19	5379	21106	5091	19090
2019/20	5507	21440	5195	19269
2020/21	5635	21773	5300	19448
2021/22	5763	22107	5405	19626
2022/23	5891	22440	5510	19805
2023/24	6019	22774	5615	19984
2024/25	6147	23107	5719	20163
2025/26	6275	23441	5824	20342
2026/27	6403	23774	5929	20520
2027/28	6531	24108	6034	20699

Data source: Independent Market Operator of Western Australia 2007, op. cit. (to 2015/16) and ACIL Tasman estimates (2015/16 to 2027/28).

2.1.2 Impact of new climate change policy

New climate change policies have potential to impact on the projections, as new measures such as the implementation of a greenhouse gas emissions trading scheme and complementary policies for energy efficiency have not

[5] Independent Market Operator of Western Australia 2007, op. cit., pp iv.

been included in the above projections. Proposed new policies for Western Australia include:

- national emissions trading from 2010
- mandatory energy efficiency audits for business, with adoption of opportunities with less than 3 year paybacks
- five star 'plus' regulations for the residential sector
- adoption of shadow 'carbon pricing' in Western Australian Government decision making from 2008 onwards.

To evaluate the impact of potential climate change policy, we have utilised the modelling conducted for the National Emissions Trading Taskforce for the proposed National Emissions Trading Scheme (NETS).[6] This represents the most developed conceptualisation of emissions trading to date. In particular, NETS Scenario 1a involved:[7]

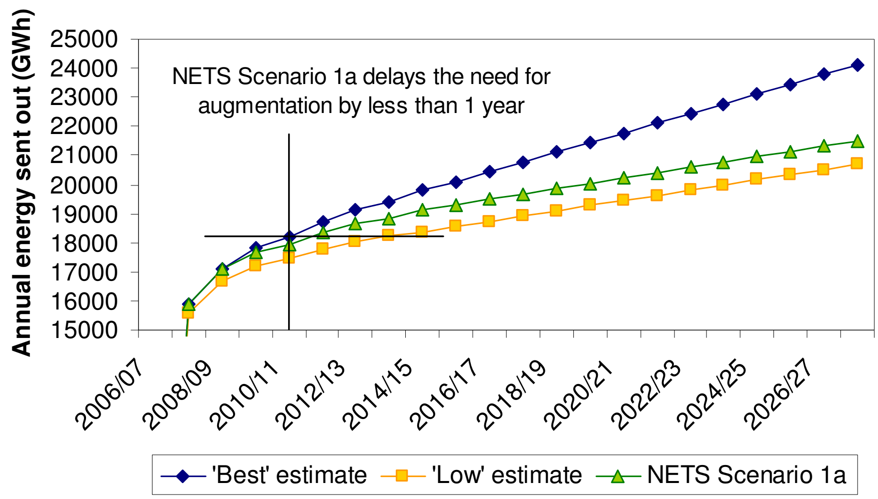
- national electricity generation emissions capped at 176 Mt CO_2e in 2030, approximately equivalent to returning electricity sector emissions to 2000 levels by that time; and
- higher assumed levels of energy efficiency, biosequestration offsets and induced (demand side) technological change.

Scenario 1a thus represents the most optimistic outlook of the NETS scenarios in terms of the ability of energy efficiency to reduce energy demand. It therefore has the greatest impact on demand growth in Western Australia, and provides a useful guide to a carbon constrained future with significant investment in energy efficiency technologies.

[6] National Emissions Trading Taskforce 2006, *Possible Design for a National Greenhouse Gas Emissions Trading Scheme: A Discussion Paper*, www.emissionstrading.net.au.

[7] National Emissions Trading Taskforce 2006, op. cit., pp 91,

Figure 1 **Electricity demand growth scenarios - SWIS**



Data source: Independent Market Operator of Western Australia 2006, op. cit., Insight Economics 2006, op.cit,, pp 35, and ACIL Tasman estimates.

The impact of the NETS Scenario 1a on overall energy growth is less than the impact of slower GDP growth (given by the 'low' scenario set out in Table 1).[8] As a result, the NETS Scenario 1a lies between the 'best' estimate projection and the 'low' estimate projection (Figure 1). Given this, a sensitivity for slower demand growth on the SWIS – using the 'low' projection – also covers the potential impact of a moderate carbon constraint through to 2030, combined with substantial investment in energy efficiency.

Inspection of Figure 1 reveals that the NETS Scenario 1a potentially delays the attainment of 'best' estimate 2010/11 levels of energy demand on the SWIS by less than 1 year, while the 'low' growth scenario has the potential to delay growth by up to three years. Impacts of the NETS Scenario 1a and the 'low' scenario in delaying *maximum demand* growth are likely to be slightly smaller – due to the more rapid growth rates for maximum demand (and assuming a uniform 'shave' resulting from energy efficiency and slower overall economic activity).

3 Methodology

3.1 Regulatory Test

Chapter 9 of the Electricity Networks Access Code 2004 (the Code) requires the Regulatory Test be applied to proposed major network augmentations.

8 Insight Economics 2006, *Impact of Emissions Trading on Western Australia*, www.greenhouse.wa.gov.au, pp 35.

The purpose of the Regulatory Test is to ensure that:

> … before a service provider commits to a proposed major augmentation to a covered network, the major augmentation is properly assessed to determine whether it maximises the net benefit after considering alternative options (Subchapter 9.1 of the Code)

The Regulatory Test determines whether a major augmentation goes ahead. Subchapter 9.2 states that

> … a service provider must not commit to a major augmentation before the Authority determines, or is deemed to determine, under section 9.13 or 9.18, as applicable, that the test in section 9.14 or 9.20, as applicable, is satisfied.

Specifically, the Regulatory Test is an assessment of whether a proposed major transmission augmentation maximises the net benefit after considering alternative options. The key components of the Regulatory Test are:

- whether the transmission option maximises the net benefit (measured in present value terms to the extent that it is possible to do so) to generators, transporters and consumers of electricity when considered against reasonable alternatives, and
- the likelihood of each alternative option arising.

3.1.1 Net benefits

A 'net benefit after considering alternative options' is defined in the Code as

> … a net benefit (measured in present value terms to the extent that it is possible to do so) to those who generate, transport and consume electricity in the covered network and any interconnected system, having regard to all reasonable alternative options, including the likelihood of each alternative option proceeding (Subchapter 9.4 of the Code)

In essence, the Regulatory Test requires a benefit-cost analysis in which the net benefit is defined as:

$$\text{Net benefit} = \text{Present value (Benefit – Cost)}$$

Measurable benefits include total capital cost savings due to deferred or avoided costs, operational cost reduction through diminished use of high cost generators, and unserved energy cost savings arising from improvements in reliability. While benefits to third parties necessarily follow improvement in the wholesale electricity market, for the purposes of this evaluation, it is sufficient to maintain the focus of the analysis on direct benefits arising within the system.

3.1.2 Reasonable alternatives

The Regulatory Test requires consideration of all reasonable alternative options, including the likelihood of each alternative option proceeding.

Reasonable options include those that may or may not involve network augmentation.

Western Power has set out the main alternatives, namely:

- Non-network options:
  - Demand Side Management
  - Generation
  - Reactive support from existing generators
- Network solutions:
  - Option 1 and variations on this option
  - Option 6 and Option 7.

3.1.3 Interpretation of net benefit

The Economic Regulation Authority suggests measuring "net benefit" as the change in consumers' plus producers' surplus.[9] Consumer surplus is defined as the difference between the benefit derived from consuming a good (or service) and the expenditure incurred in procuring that good or service. Producer surplus is the difference between a producer's revenue and total variable cost.[10] Together, consumer and producer surplus comprise aggregate net social benefit.

Defined in this way, net benefit has a precise definition, which in turn facilitates application of the Regulatory Test. The key issue is that the requirement to demonstrate that the proposed augmentation maximises net benefit is equivalent to a demonstration that there is a reasonable likelihood that aggregate net social benefit is maximised.

Transfers of benefits between generators, transporters and consumers

One aspect of the Economic Regulation Authority's suggested definition of net benefit that is important to consider is the possibility of transfers of benefits between generators, transporters and consumers. For example, consumers required to provide a capital contribution would experience

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[9] Economic Regulation Authority, *Draft Discussion Paper on Regulatory Test Guidelines for the South West Interconnected Network*, June 2007.

[10] See C.J. McKenna and R. Rees, (1992) *Economics: A Mathematical Introduction*, New York: Oxford University Press.

diminished consumer surplus compared to the situation where a capital contribution is not required (i.e. the transporter absorbs the cost). This situation would represent no change in net benefit; the cost of the capital contribution has merely been transferred.

Cost subadditivity as a potential source of net benefit

With reference to the Regulatory Test, where growth in transmission load is likely, building *extra capacity* to meet *as yet unrealised but anticipated* growth is likely to yield a net benefit. This is due to the likelihood of cost subadditivity, which arises whenever a single large augmentation is less costly than multiple smaller augmentations. [11] This cost differential often occurs because of economies of scale due, in part, to the sunk cost that is incurred each time the network is augmented.

Uncertainty complicates this argument somewhat. First, there is uncertainty with respect to the long-run capacity required. Overbuilding capacity risks an unnecessarily high transmission cost. On the other hand, there is uncertainty associated with: imposing delays on electricity-dependent projects and other developments; potential cost blowouts with each augmentation; and deteriorating network reliability.

Examples of other net benefits

The Economic Regulation Authority suggests a wide range of possible changes to net benefits.[12] These include: changes in transmission capital and operating cost; changes in network reliability; changes in network efficiency; and competition benefits.

Changes in competition benefits require some consideration. It is commonly assumed that an increase in competition is necessarily an increase in net benefit. Note, however, that competition is merely a mechanism and not, of itself, a benefit.

This can be seen by considering the change in net benefit (i.e. aggregate net social benefit) that occurs as a result of a change in competition. Up to some point, an increase in competition may yield price reductions as supplier mark-up over cost is reduced. However, competition means that the high *fixed* cost in supplying electricity creates duplication in some fixed costs, such as management and administration. This induces an increase in total network cost. Hence, there is a potential trade-off between the system-wide benefit of

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[11] See William J. Baumol (1986). *Microtheory: Applications and Origins*, MIT Press.

[12] Economic Regulation Authority, op. cit., p9.

competition and the duplication in fixed cost that may accompany increased competition.

3.2 Evaluation based on economic principles

In order to evaluate likely market outcomes, it is necessary to rigorously analyse market participants in an internally consistent and objective manner. To facilitate this, ACIL Tasman has developed a comprehensive model of the Western Australia wholesale electricity market (WEM), which provides estimates of the spot price for energy from the STEM and dispatch by each generating unit on a half hour basis. The model is called *PowerMark WA* – a member of ACIL Tasman's family of electricity and gas market models.

PowerMark WA produces estimates of generation unit dispatch and dispatch weighted STEM prices for each half-hourly trading interval.

These are based on a series of input assumptions and estimates regarding electricity demand, generator costs, installed plant capacity, contract coverage, planned and unplanned plant outages and marginal loss factors.

PowerMark WA has been used extensively for this study.

4 The options

As required under the Code, Western Power has considered a range of alternative options, which are divided into network and non-network options. According to Chapter 9 – Regulatory Test (page 5595 of the Code), the Regulatory Test "…cannot require a project involving the generation or consumption of electricity to be located in a particular place or to be altered in any other way. The [Regulatory Test] can only affect what network augmentations are undertaken in order to accommodate the project…"

Part of this evaluation, therefore, is to determine (to the extent that it is practical to do so) both the actual and likely locations of generation and consumption of electricity.

For the purposes of this evaluation, the relevant location of consumption is the Perth metropolitan area. In the sections that follow, the load growth in this area is examined to determine its likely time path under a variety of scenarios.

Given the analysis of consumption in the Perth metropolitan area, we consider the likely generation requirements to meet the expected demand for electricity. This requires, in the first instance, analysis of the location and capacity of existing generation, which includes anticipated generator decommissioning. We then consider likely location and capacity of replacement generators as well as generators required to satisfy new demand.

In this evaluation, the likely location of generators is divided into those that are within the Perth metropolitan area and those outside the Perth metropolitan area. In our modelling, the likely location of generators is determined by factors such as the location of the primary energy source, the delivered price of that energy, the location of the demand for electricity and the constraints that may be placed on potential generator sites.

From a net benefits perspective, we consider the most efficient generation mix based on the proportion of coal-fired and gas-fired generators. To simplify matters, we assume that coal-fired generation is likely to be located as close as possible to the coal source, as this minimises transport cost.[13] This implies that all new coal-fired generation is likely to be located in the South West (outside the Perth metropolitan area). Gas-fired generators, on the other hand, are able to be located inside the Perth metropolitan area as gas is relatively easier to transport than coal and does have an existing network of high capacity pipelines in place.

Thus, we have a situation in which generation location is, in large part, dictated by the type of fuel used. This implies that the need for network augmentation connecting the Perth metropolitan area to the South West region increases as the proportion of coal-fired generation in the generation portfolio increases. The greater the proportion of gas-fired generation, which is assumed to be located in the Perth metropolitan area, the less is the need for network augmentation.

[13] Note that we implicitly assume that transporting electricity is always less costly than transporting Western Australian coal.

5 Generation options

5.1 Introduction

This section of the report examines whether local generation nearer the main load centres of Perth and Kwinana or transmission of power from the low cost generation sites in the South West provide the lower electricity supply (generation plus transmission) cost and the lower cost to electricity consumers.

ACIL Tasman has been advised by Western Power that the proposed South West transmission augmentation, which is the subject of this report, will provide an additional 1,100MW of transmission capacity from the South West which would allow for a further 1,100MW of low cost generation in the South West region. The 1,100MW is the additional capacity available after two 140MW Pinjarra cogeneration units, the two 160MW Wagerup open cycle gas turbines at Wagerup and the two 220MW Bluewaters units due for completion by late 2009.

Without the South West transmission augmentation, the future generation options is assumed be combined cycle gas turbines (CCGTs) close to the major load centres of Perth and Kwinana.

ACIL Tasman has used *PowerMark WA* to study two options under a variety of market scenarios for load growth and emissions trading. The modelling covers the 20 year period commencing 2008/09.

The two options studied are:

- Generation in the South West region with transmission augmentation **(SWGEN)**
- Generation in the metropolitan area near the major load centres without transmission augmentation **(METROGEN)**

In order to ensure the robustness of the model findings seven market scenarios were studied as follows:

- Business as usual **(BAU)**
- Emissions trading capped at $30/tCO2e **(ET30)**
- Emissions trading capped at $20/tCO2e **(ET20)**
- Low forecast growth with $30 emissions trading cap **(LLF)**
- High gas price with $30 emissions trading cap **(HGP)**
- High gas with $20 emissions trading cap **(HGET20)**
- 2007 load forecast with $20/tCO2e emissions trading cap **(2007LF)**

Using the modelling results, ACIL Tasman has estimated net present cost of generation and the net present cost of electricity to consumers over the 20 years to 2027/28. If, after adding the net present cost of the South West augmentation to those scenarios involving additional low cost generation in the South West, the net present cost of electricity supply is lower than the local generation without transmission augmentation, then the transmission augmentation could be seen to be justified.

The modelling is based on a wide variety of assumptions and these need to be considered when interpreting the modelling results. Many of the key modelling assumptions are subject to a degree of uncertainty including:

- capital cost of generating plant;
- fixed and variable operating costs of generators
- fuel costs
- load forecast
- future emissions trading arrangements,
- market contract cover
- discount rate
- steam price paid to co-generators.

5.2 The generation options

The two generation options are discussed in more detail in this section

5.2.1 South West generation option (SWGEN)

SWGEN assumes the South West transmission augmentation goes ahead thereby allowing further development of 1,100MW of low cost base load generation in the South Western region. This generation includes further gas fired Alinta cogeneration plants at Alcoa's Wagerup and Pinjarra alumina refineries and additional coal fired thermal units at Collie. Any base load plant requirements beyond the 1,100MW during the 20 year period are met by combined cycle gas turbines (CCGTs) assumed to be located near to the major load centres.

5.2.2 Metropolitan generation option (METROGEN)

METROGEN assumes that the South West transmission augmentation does not take place and that all new base load generation is in the form of gas fired CCGTs located close to the major load centres of Perth and Kwinana.

5.3 The market scenarios

Seven market scenarios were modelled for each of the generation options. These scenarios were selected to check the robustness of the model results under a wide variety of market conditions.

5.3.1 Business as usual (BAU)

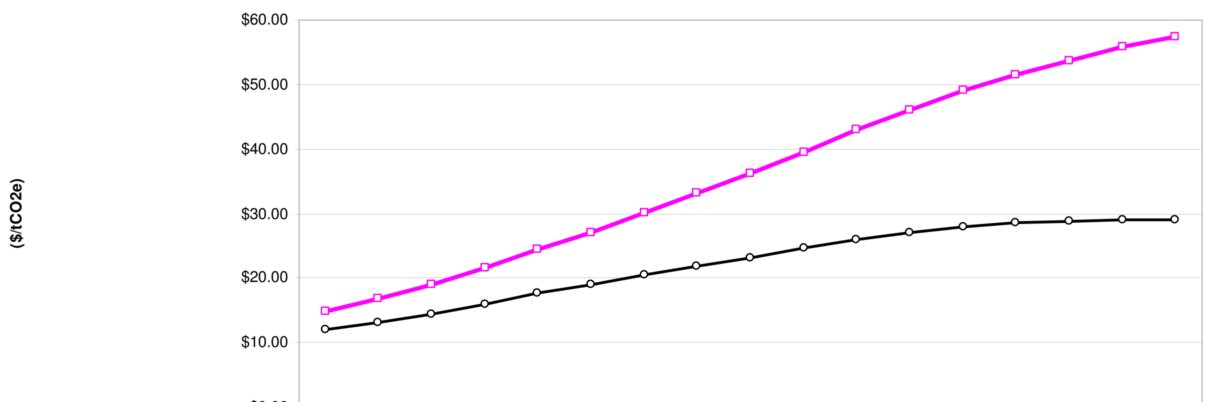
The BAU scenarios are based on a continuation of the current market conditions with no emissions trading scheme. Of the three market scenarios the BAU can be expected to be the one most likely to favour the transmission augmentation case as the low cost base load generation coming on line in the South West region will be maximised and not be adversely affected by emissions trading.

5.3.2 Emissions trading capped at $30/tCO2e (ET30)

The ET30 scenario uses the same load forecast and plant assumptions as the BAU but includes an emissions trading scheme along the lines of the Scenario 1 developed by the National Emissions Trading Taskforce (NETT).

Under the NETT Scenario 1 the price for emissions is as shown in Figure 2.

Figure 2 **Price for emissions in ET30 ($/tonne of CO2e)**



	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28
Emissions price (real 2006 $/tCO2e)	$12.00	$13.20	$14.50	$16.00	$17.60	$19.00	$20.50	$21.90	$23.20	$24.60	$26.00	$27.10	$28.00	$28.50	$28.80	$29.10	$29.10
Emissions price (nominal $/tCO2e)	$14.76	$16.72	$18.92	$21.50	$24.36	$27.09	$30.10	$33.13	$36.14	$39.48	$42.97	$46.14	$49.10	$51.47	$53.58	$55.76	$57.43

Data source: NETT discussion paper August 2006 - Scenario 1

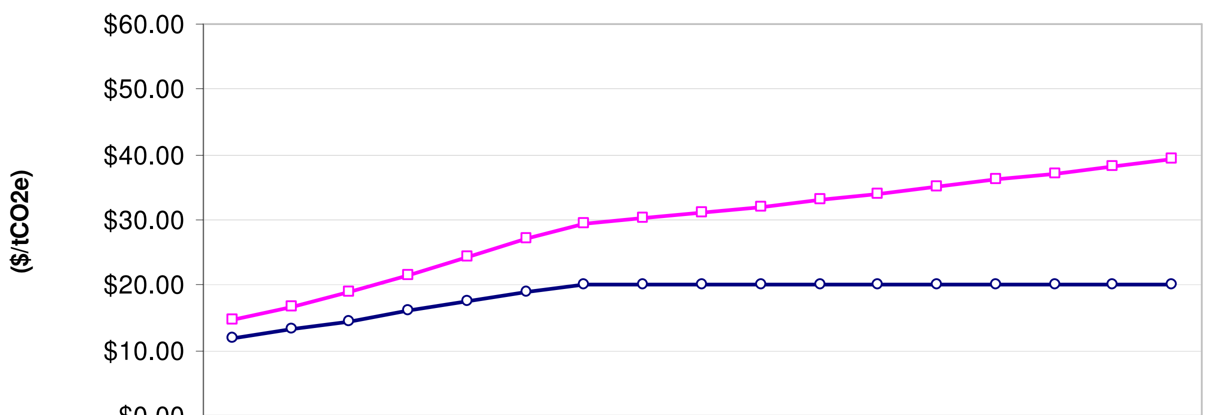
On 1 June 2007 the Commonwealth Task Group on emission trading reported and recommended a wider application of the trading scheme to the whole economy not just the electricity sector. The two schemes are similar in many respects although under the Commonwealth scheme existing emitters will be issued sufficient free emissions to allow return to profitability to a level in line with the economy overall rather than to the level which would have been achieved without the scheme. This means that, if the emissions trading caused a decline in general profitability in the economy of say 5%, then free emission rights would be sufficient to allow individual generators a similar decline in profitability. On the positive side however, the price for emission rights is expected to be much lower under the Commonwealth scheme (probably less than $20.00/t CO2e) being based on the cost of carbon sinks rather than at a level to achieve changes in generation technology to achieve the targeted emissions.

5.3.3 Emissions trading capped at $20/tCO2e (ET20)

The ET20 scenario uses the same load forecast and plant assumptions as the BAU but includes an emissions trading scheme along the lines of that developed by the National Emissions Trading Taskforce (NETT) except that the real 2006 price for emissions has been capped at $20.00/tCO2e. This reflects the possible lower price for emissions under the wider scheme being considered by the Commonwealth.

Under the ET20 scenario the price for emissions is as shown in Figure 3.

Figure 3 **Price for emissions in ET20 ($/tonne of CO2e)**



	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28
Real 2006 $/tCO2	$12.00	$13.20	$14.50	$16.00	$17.60	$19.00	$20.00	$20.00	$20.00	$20.00	$20.00	$20.00	$20.00	$20.00	$20.00	$20.00	$20.00
nominal $/tCO2e	$14.76	$16.72	$18.92	$21.50	$24.36	$27.09	$29.37	$30.25	$31.16	$32.09	$33.06	$34.05	$35.07	$36.12	$37.21	$38.32	$39.47

Data source: NETT discussion paper August 2006 - Scenario 1

5.3.4 Low forecast growth with $30 emissions trading cap (LLF)

The LLF scenario involves low load growth with emissions trading. The low load forecast from the 2006 IMO 2006 Statement of Opportunity (SOO) was used as the load forecast and the plant timings adjusted to match. The lower growth is seen to ensue from a response to higher electricity prices under the emission trading scheme, energy efficiency improvements and greater renewable generation.

This market scenario is presented as the one most likely to support local gas fired generation with deferment or abandonment of the proposed South West transmission augmentation.

The LLF scenario incorporates the $30 emissions price assumption.

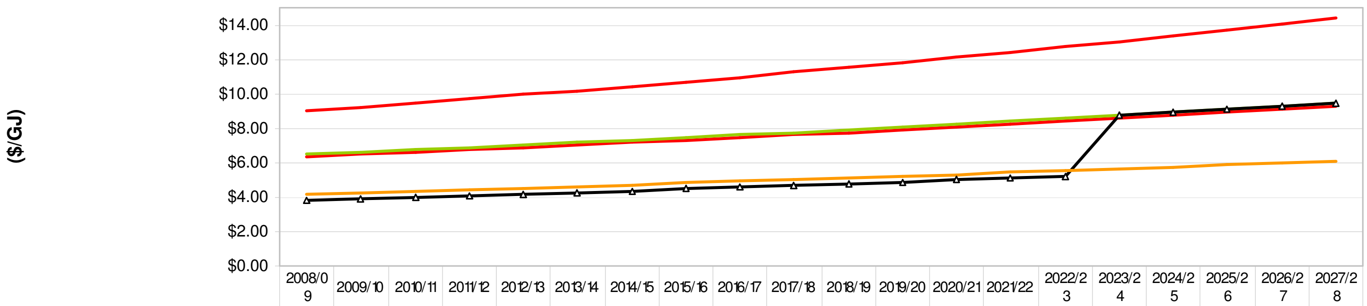
5.3.5 High gas price with $30 emissions trading cap (HGP)

The HGP scenario has been included because of the uncertainty over future gas availability and price in Western Australia. The assumptions for the HGP scenario are the same as the EG30 scenario except that the gas price has been increased beyond 2014 by around $1.00/GJ in 2007 terms. This means the higher gas price assumed in all other scenarios for the initial years does not fall back from around $4.00/GJ at the well head in 2007 terms to $3.00/GJ.

The gas prices used in the HGP scenario are shown in Figure 4. It shows that the gas price to Perth has been increased by $1.10/GJ in 2013/14 which increases in nominal terms to $1.35/GJ by 2027/28. This high gas price assumes that no major new competitive source of domestic gas is brought into production to place downward pressure on domestic prices and that domestic gas prices approximate the net back value of gas used in LNG production.

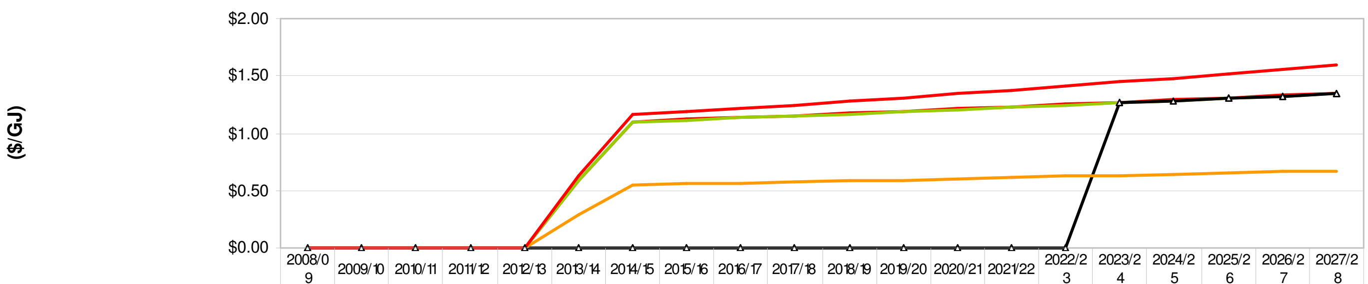
Figure 4 **Gas prices used in the HGP Scenario and the difference with the BAU Scenario**

Gas prices used in HGP Scenario



	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28
Gas - Perth	$6.36	$6.49	$6.62	$6.75	$6.88	$7.02	$7.16	$7.31	$7.45	$7.60	$7.75	$7.91	$8.07	$8.23	$8.39	$8.56	$8.73	$8.91	$9.08	$9.27
Gas - South of Perth	$6.49	$6.62	$6.75	$6.89	$7.02	$7.17	$7.31	$7.45	$7.60	$7.76	$7.91	$8.07	$8.23	$8.40	$8.56	$8.73	$8.91	$9.09	$9.27	$9.45
NewGen gas price	$3.83	$3.91	$4.00	$4.09	$4.18	$4.28	$4.37	$4.47	$4.57	$4.67	$4.78	$4.89	$5.00	$5.11	$5.22	$8.73	$8.91	$9.09	$9.27	$9.45
Coal and gas into Kwinana (50%coal)	$4.19	$4.28	$4.36	$4.45	$4.54	$4.63	$4.72	$4.82	$4.91	$5.01	$5.11	$5.21	$5.32	$5.42	$5.53	$5.64	$5.75	$5.87	$5.99	$6.11
Goldfields gas price	$9.00	$9.23	$9.46	$9.69	$9.93	$10.18	$10.44	$10.70	$10.97	$11.24	$11.52	$11.81	$12.10	$12.41	$12.72	$13.03	$13.36	$13.69	$14.04	$14.39

Increase over the BAU Scenario



	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28
Gas - Perth	$0.00	$0.00	$0.00	$0.00	$0.00	$0.58	$1.10	$1.12	$1.14	$1.16	$1.17	$1.19	$1.21	$1.23	$1.25	$1.27	$1.29	$1.31	$1.33	$1.35
Gas - South of Perth	$0.00	$0.00	$0.00	$0.00	$0.00	$0.59	$1.10	$1.12	$1.13	$1.15	$1.17	$1.19	$1.21	$1.22	$1.24	$1.26	$1.28	$1.30	$1.32	$1.34
NewGen gas price	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$1.26	$1.28	$1.30	$1.32	$1.34
Coal and gas into Kwinana (50%coal)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.29	$0.55	$0.56	$0.57	$0.58	$0.58	$0.59	$0.60	$0.61	$0.62	$0.63	$0.64	$0.65	$0.66	$0.67
Goldfields gas price	$0.00	$0.00	$0.00	$0.00	$0.00	$0.63	$1.16	$1.19	$1.22	$1.25	$1.28	$1.31	$1.34	$1.38	$1.41	$1.45	$1.48	$1.52	$1.56	$1.60

Data source: ACIL Tasman modelling assumptions

5.3.6 High gas with $20 emissions trading cap (HGET20)

The HGET20 scenario is based on the same assumptions as the ET20 scenario but with the higher gas prices used in the HGP scenario as shown in Figure 4.

5.3.7 2007 load forecast with $20 emissions trading cap (2007LF)

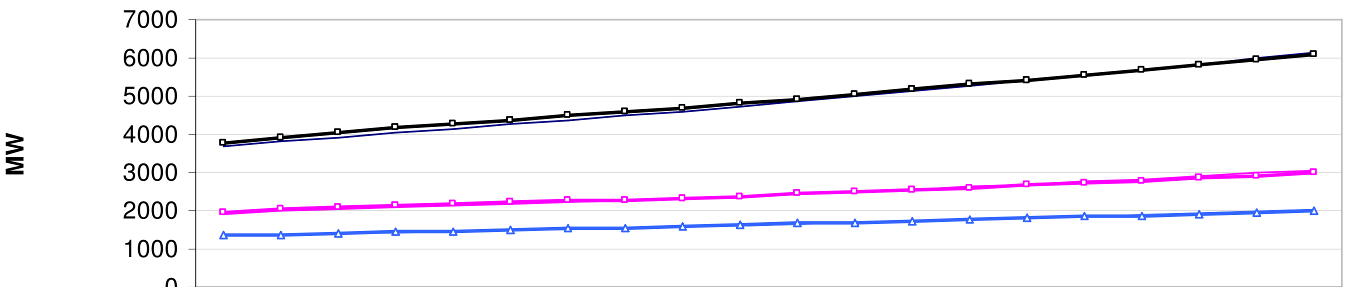
Since completion of modelling based on the 2006 IMO forecast, the 2007 load forecast has been released by the IMO in its 2007 SOO. Noting the impact on the modelling results, it was decided that a 2007LF scenario be developed as part of the assessment.

The 2007 50% probability of exceedance (POE) forecast of peak demand and its comparison with the 2006 forecast is shown in Figure 5. The change is upwards in the initial years of the projection but lower in the latter years of the projection with higher initial loads but lower load growth in the 2007 forecast.

The forecast differences are not regarded as significant in the longer term.

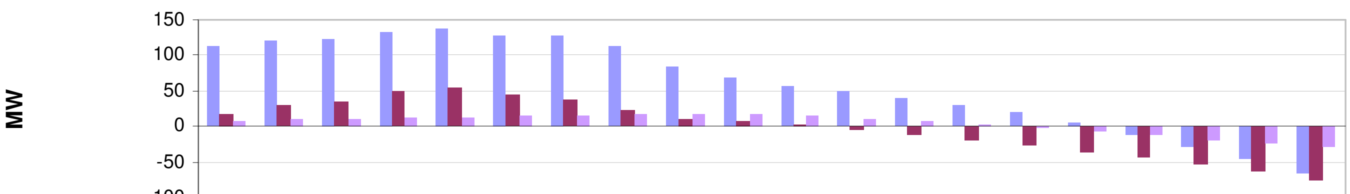
Figure 5 **2006 and 2007 peak, average and minimum demand forecasts (medium growth 50% POE)**

2006 and 2007 load forecasts



	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28
2006 peak (MW)	3678	3803	3914	4033	4143	4251	4374	4479	4607	4738	4871	5003	5133	5266	5403	5543	5688	5835	5987	6143
2006 average (MW)	1931	2005	2041	2089	2131	2171	2224	2269	2322	2376	2433	2494	2558	2625	2693	2763	2835	2909	2984	3062
2006 Min (MW)	1347	1374	1401	1429	1458	1487	1517	1547	1579	1610	1646	1683	1723	1764	1806	1849	1893	1938	1985	2032
2007 peak (MW)	3791	3924	4037	4166	4281	4380	4501	4593	4691	4808	4928	5052	5173	5297	5424	5549	5677	5807	5941	6077
2007 average (MW)	1949	2034	2075	2139	2186	2217	2262	2292	2333	2384	2437	2490	2548	2606	2666	2728	2790	2854	2920	2987
2007Min (MW)	1356	1383	1412	1441	1471	1501	1532	1564	1597	1629	1661	1694	1730	1766	1803	1841	1880	1920	1961	2002

Changes between 2006 and 2007



	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28
Peak (MW)	113	121	123	133	138	129	127	114	84	70	57	49	40	31	21	5	-11	-28	-46	-66
Average (MW)	18	30	34	51	55	46	38	23	11	9	4	-3	-11	-19	-27	-36	-45	-54	-64	-75
Minimum (MW)	9	10	11	12	13	14	16	17	18	18	16	11	7	3	-2	-7	-12	-18	-24	-30

Data source: IMO 2006 and 2007 SOOs with ACIL Tasman forecast of minimum load and extension to to 2027/28 and

6 Modelling assumptions

The *PowerMark WA* model requires a number of key assumptions regarding:

- electricity forecast
- market supply
- contract cover
- new entrant costs
- other assumptions.

6.1 Electricity forecast

The market modelling is generally based on the expected growth, 50% probability of exceedance, load forecast from the Independent Market Operator (IMO) in its 2006 SOO.

Since the modelling has been completed the IMO has released its 2007 SOO which incorporates a load forecast which is slightly higher than the 2006 SOO in the initial years but with generally lower growth as shown in Figure 5 above. The main findings are that

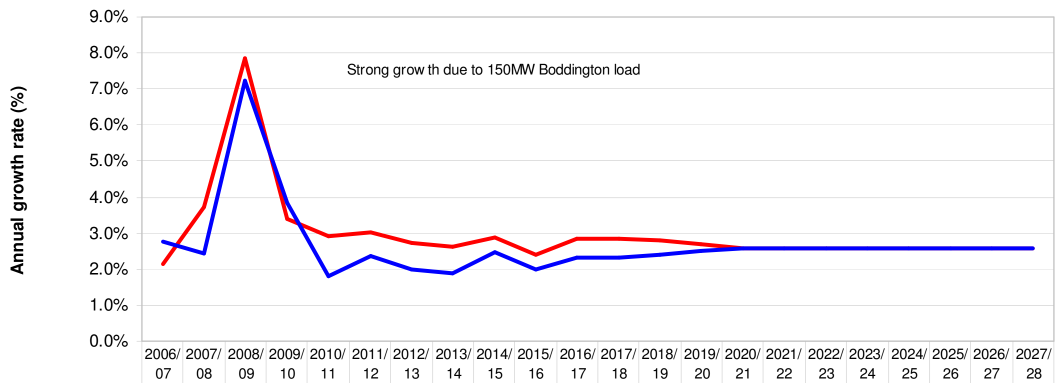
- peak load is up to 138MW
- average load is higher by up to 55MW
- load growth is however lower for both peak and average demand by 0.2%pa and 0.1%pa respectively

A market scenario using the 2007 load forecast has been included.

Forecasts of annual energy (GWh sent-out) and peak demand (MW sent-out) are important inputs to the modelling.

For all scenarios apart from LLF and 2007LF scenarios the modelling is based on medium growth 50% probability of exceedence (POE) forecast of peak demands and annual energy to 2015–16 published in the IMO 2006 SOO. The projection beyond 2015–16 by ACIL Tasman is at the same average growth as forecast for the ten years to 2015–16 as published by the IMO in the 2006 SOO. Figure 6 summarises the percentage annual growth in energy and peak demand.

Figure 6 **Growth in energy and peak demand – all scenarios except LLF and 2007LF**

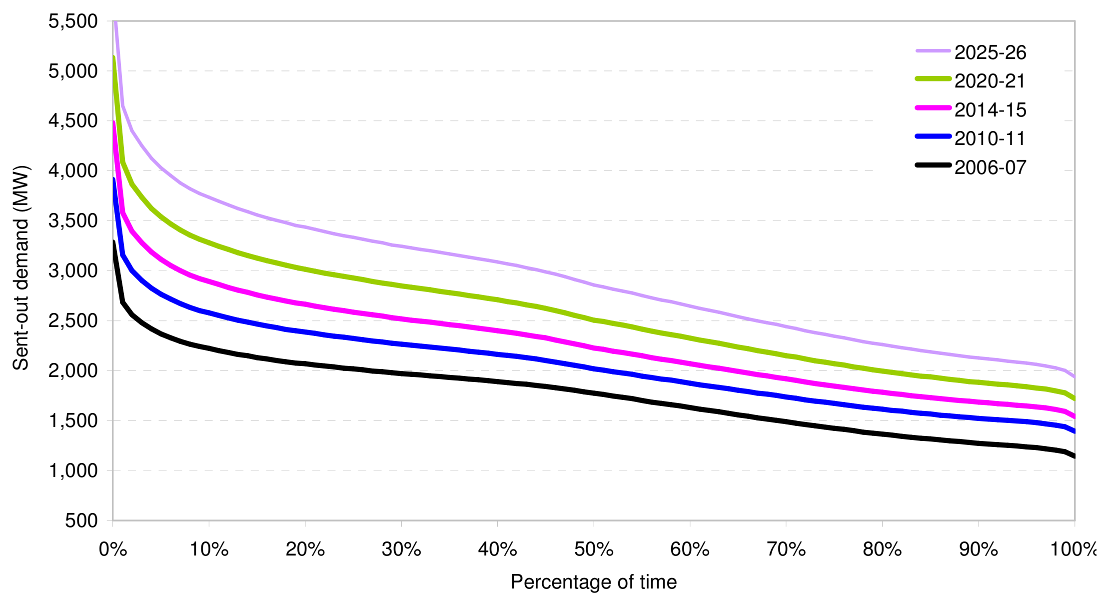


	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28
Peak load	2.1%	3.7%	7.9%	3.4%	2.9%	3.0%	2.7%	2.6%	2.9%	2.4%	2.9%	2.9%	2.8%	2.7%	2.6%	2.6%	2.6%	2.6%	2.6%	2.6%	2.6%	2.6%
Energy	2.8%	2.4%	7.2%	3.8%	1.8%	2.3%	2.0%	1.9%	2.5%	2.0%	2.3%	2.3%	2.4%	2.5%	2.6%	2.6%	2.6%	2.6%	2.6%	2.6%	2.6%	2.6%

Data source: IMO 2006 SOO with projection to 2027/28 by ACIL Tasman

Figure 7 provides load duration curves for selected years used in the modelling.

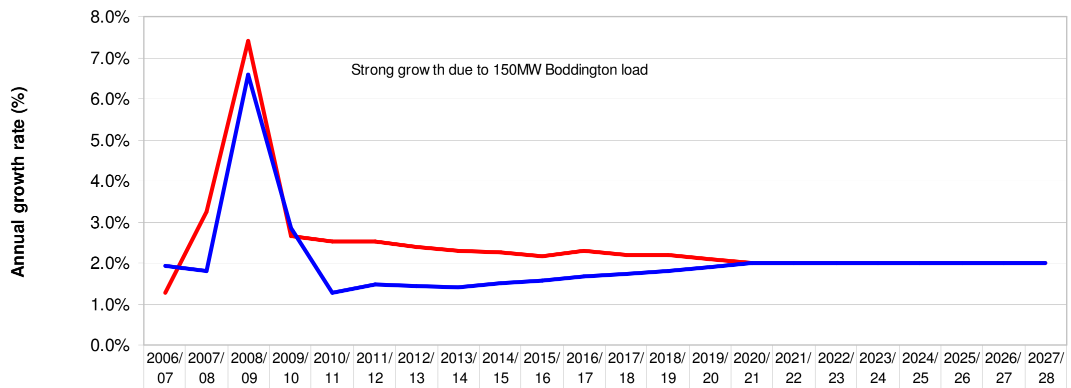
Figure 7 **Projected SWIS load duration curves - all scenarios except LLF and 2007LF**



Data source: ACIL Tasman

The LLF scenario is based on the IMO 2006 SOO low growth 50%POE forecast was used and again projected forward by ACIL Tasman. ACIL Tasman adjusted the low growth peak demand to include the 150MW Boddington load which was not included in the IMO forecast of peak demand but did appear in the annual energy forecast. Figure 8 summarises the percentage annual growth in energy and peak demand.

Figure 8 **Growth in energy and peak demand - LLF scenario**

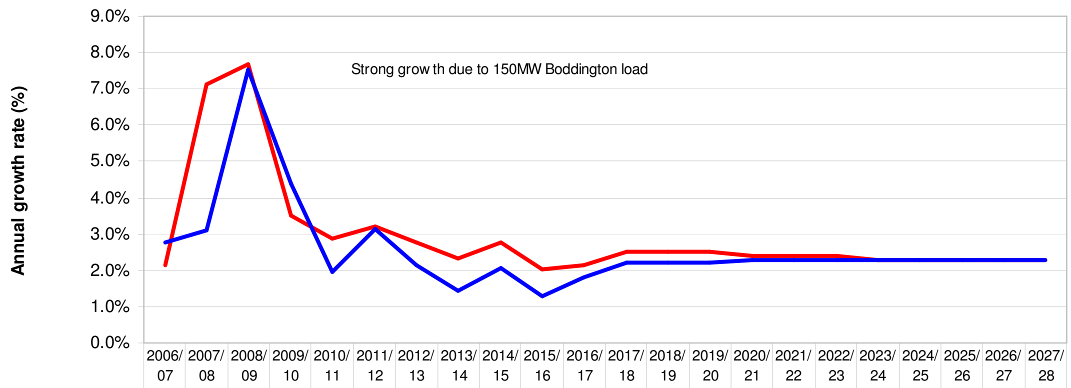


	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28
Peak load	1.3%	3.3%	7.4%	2.7%	2.5%	2.5%	2.4%	2.3%	2.3%	2.2%	2.3%	2.2%	2.2%	2.1%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
Energy	1.9%	1.8%	6.6%	2.9%	1.3%	1.5%	1.5%	1.4%	1.5%	1.6%	1.7%	1.7%	1.8%	1.9%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%

Data source: IMO 2006 SOO with projection to 2027/28 by ACIL Tasman

The 2007LF scenario is based on the IMO 2007 SOO medium growth 50%POE forecast and again projected forward by ACIL Tasman. The percentage annual growth in energy and peak demand for the 2007 forecast is shown in Figure 9. It can be seen that the long term growth used by ACIL Tasman to extend the 2007 IMO forecast of the demand and annual energy is 2.3% compared with 2.6% used to extend the 2006 forecast. The reduction in forecast long term growth reflects the lower growth in the 10 year IMO forecast for the 2007 SOO.

Figure 9 **Growth in energy and peak demand – 2007LF scenario**



	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28
Peak load	2.1%	7.1%	7.7%	3.5%	2.9%	3.2%	2.8%	2.3%	2.8%	2.0%	2.1%	2.5%	2.5%	2.5%	2.4%	2.4%	2.4%	2.3%	2.3%	2.3%	2.3%	2.3%
Energy	2.8%	3.1%	7.5%	4.4%	2.0%	3.1%	2.2%	1.4%	2.1%	1.3%	1.8%	2.2%	2.2%	2.2%	2.3%	2.3%	2.3%	2.3%	2.3%	2.3%	2.3%	2.3%

Data source: IMO 2006 SOO with projection to 2027/28 by ACIL Tasman

6.2 Market supply

There are six market supply futures used in the modelling:

1. SWGEN option with all scenarios except LLF and 2007LF involving up to an additional 1,100MW of additional low cost base load generation capacity in the South West and less local gas fired generation.
2. METROGEN option with all scenarios except LLF and 2007LF where there is no additional coal or cogen capacity in the South West region and all new base load is in the form of CCGTs assumed to be close to load centres mainly in the Perth metropolitan region.
3. SWGEN option with LLF market scenario involving an additional 1,100MW of additional low cost base load generation capacity in the South West and less local gas fired generation.
4. METROGEN option with LLF scenarios where all new base load is in the form of CCGTs assumed to be close to load centres mainly in the Perth metropolitan region.
5. SWGEN option with 2007LF market scenarios involving an additional 1,100MW of additional low cost base load generation capacity in the South West and less local gas fired generation.
6. METROGEN option with 2007LF scenarios where all new base load is in the form of CCGTs assumed to be close to load centres mainly in the Perth metropolitan region.

Future capacity to supply electricity during the projection period is dependent on:

- capacity and type of existing generation
- capacity, type and timing of plant retirements

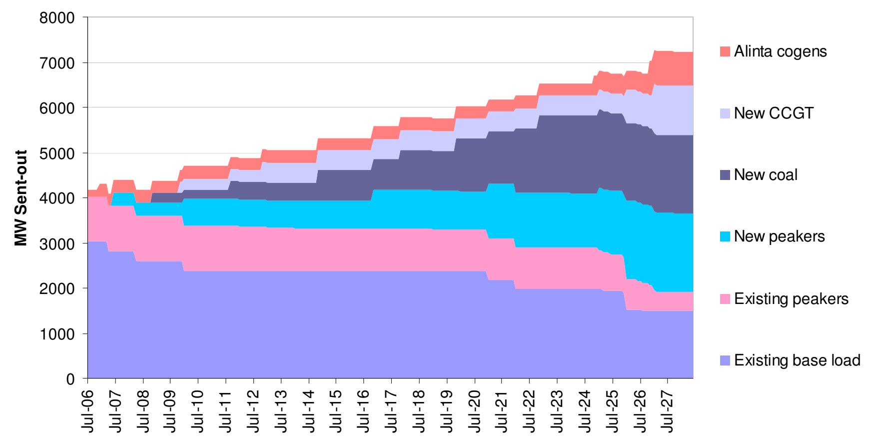
- capacity, type and timing of new plant (new entrants)
- frequency and length of maintenance programmes as well as assumed forced outage rates.

ACIL Tasman has taken into account information obtained from the market as well as published by the IMO in its SOO when constructing the assumptions regarding the timing of new plant and withdrawal of existing plant. It is also assumed that Verve's limit of 3,000 MW remains in force throughout the 20 years of the projections.

6.2.1 Generation BAU and ET30 summary

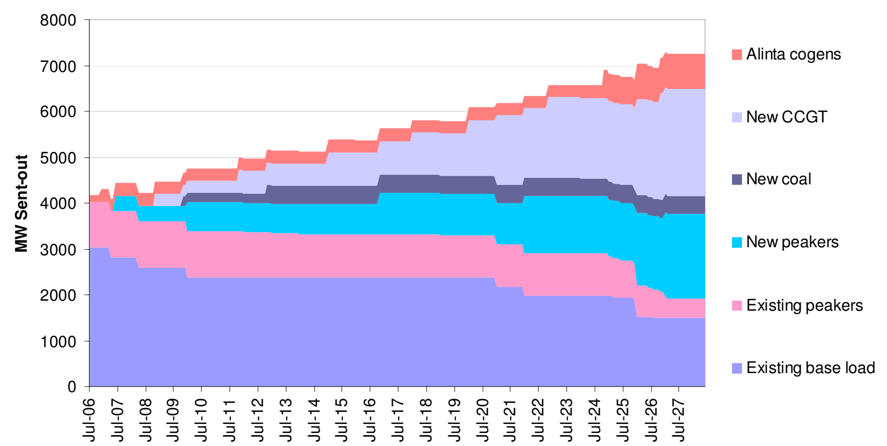
A summary of generation capacity by plant type in the WEM for the BAU and ET30 market scenarios is provided in Figure 10 and Figure 11. Note the high level of CCGT capacity in the METROGEN option.

Figure 10 **Generation capacity by plant type – SWGEN option into all scenarios except LLF and 2007LF**



Data source: ACIL Tasman generator database

Figure 11 **Generation capacity by plant type – METROGEN option into all scenarios except LLF and 2007LF**

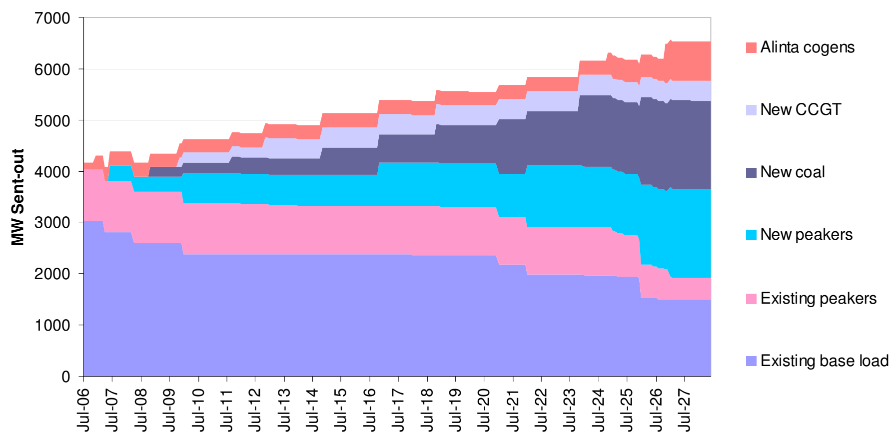


Data source: ACIL Tasman generator database

6.2.2 Generation SWGEN and METROGEN into LLF summary

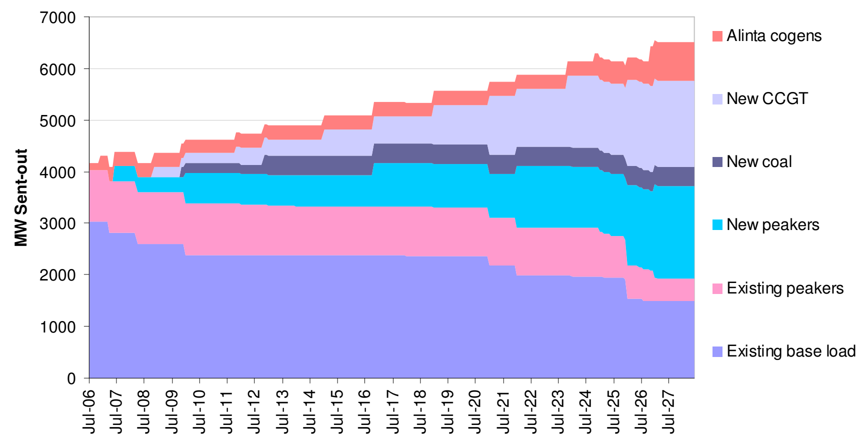
A summary of generation capacity by plant type in the WEM for the LLF market scenarios is provided in Figure 12 and Figure 13. Again note the high level of CCGT capacity in the METROGEN option.

Figure 12 **Generation capacity by plant type – SWGEN option into LLF scenario**



Data source: ACIL Tasman generator database

Figure 13 **Generation capacity by plant type – METROGEN option into LLF scenario**

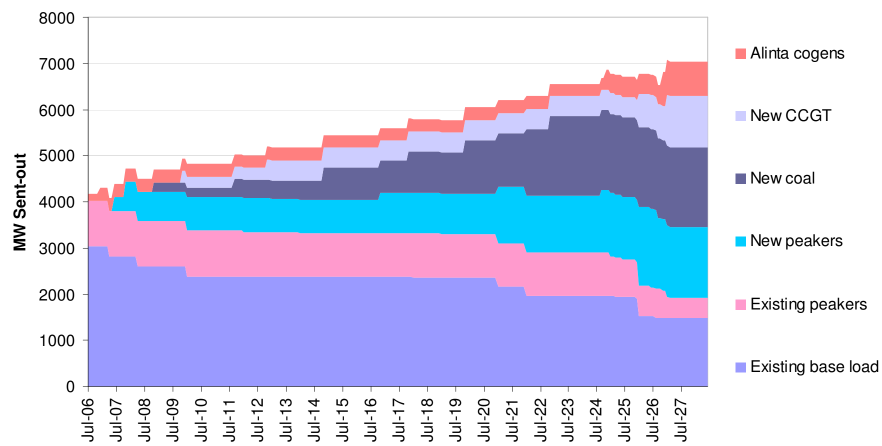


Data source: ACIL Tasman generator database

6.2.3 Generation SWGEN and METROGEN into 2007LF summary

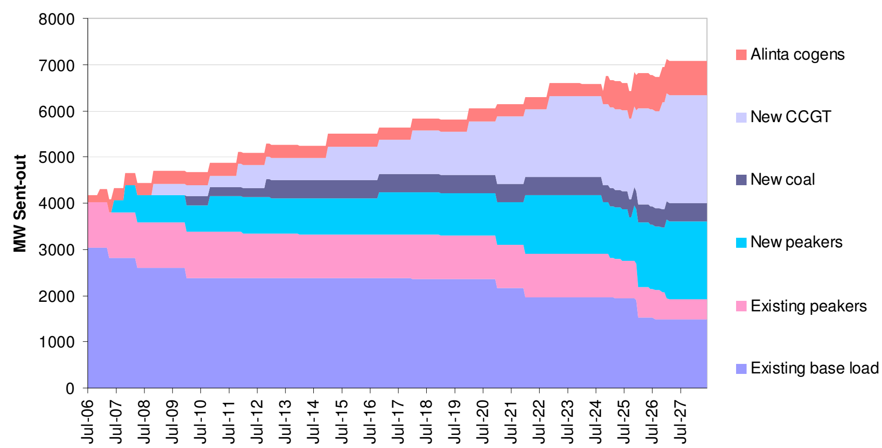
A summary of generation capacity by plant type in the WEM for the 2007LF market scenarios is provided in Figure 14 and Figure 15. Again note the high level of CCGT capacity in the METROGEN option.

Figure 14 **Generation capacity by plant type – SWGEN option into 2007LF scenario**



Data source: ACIL Tasman generator database

Figure 15 **Generation capacity by plant type – METROGEN option into 2007LF scenario**



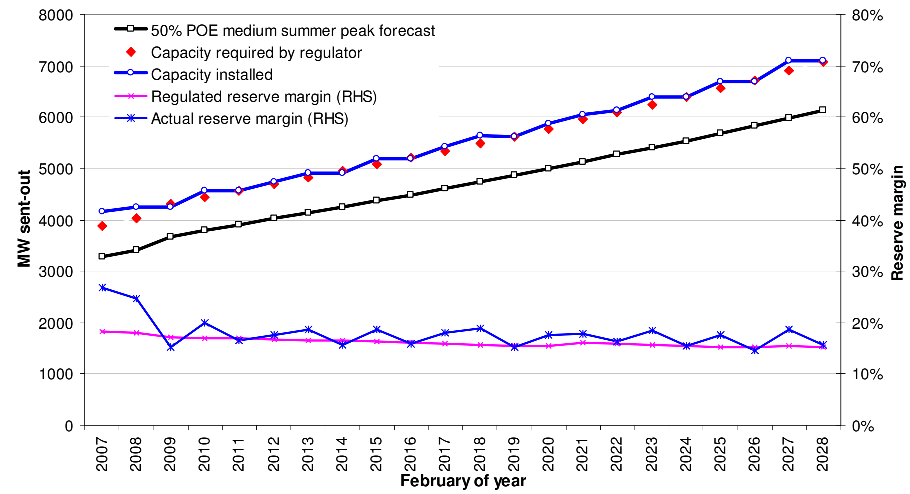
Data source: ACIL Tasman generator database

6.2.4 Supply – demand balance

The balance between plant and load is an important determinant of the STEM price. In the modelling the plant capacity is set to meet the regulated requirement.

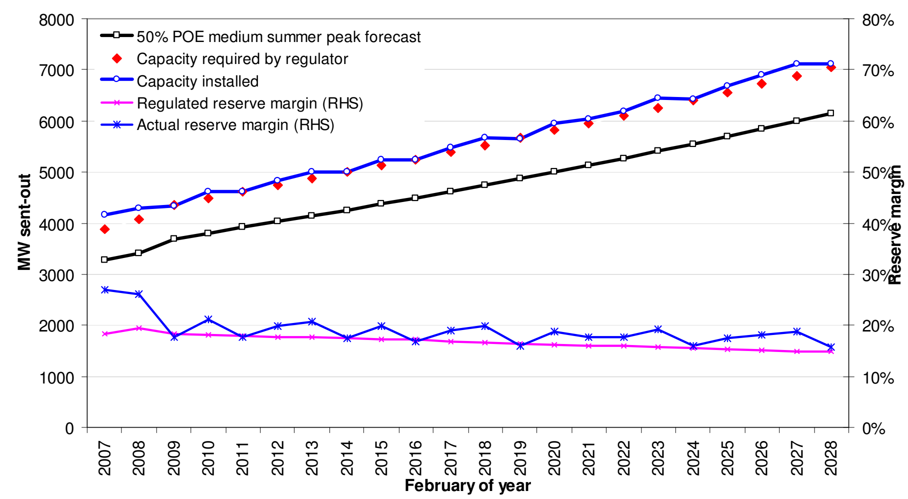
This results in a regulated reserve margin, which declines, from around 18% in 2007-08 to around 15% by the end of the modelling period. The relationship between generation capacity, load and the regulated and actual reserve margins are shown in Figure 16 to Figure 21.

Figure 16 **Annual load-plant balance and reserve margin – SWGEN option for all scenarios except LLF and 2007LF**



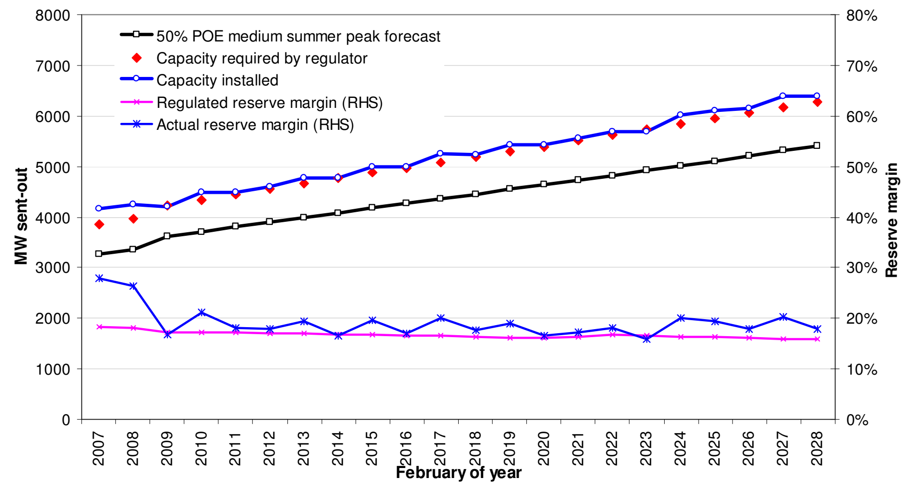
Data source: ACIL Tasman generator database

Figure 17 **Annual load-plant balance and reserve margin – METROGEN option for all scenarios except LLF and 2007LF**



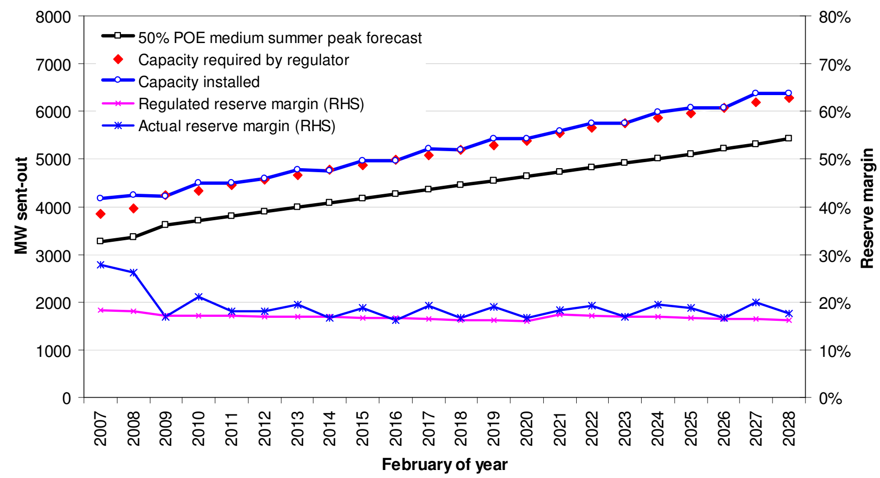
Data source: ACIL Tasman generator database

Figure 18 **Annual load-plant balance and reserve margin – SWGEN option with LLF scenario**



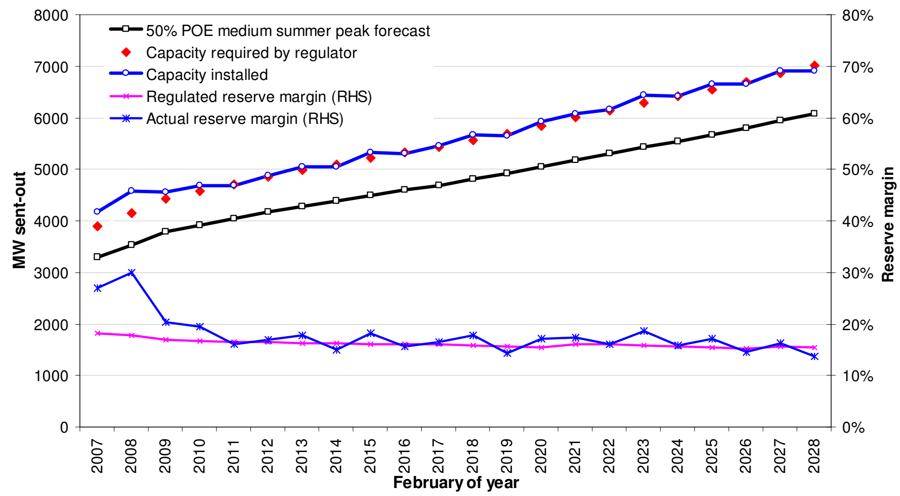
Data source: ACIL Tasman generator database

Figure 19 **Annual load-plant balance and reserve margin – METROGEN option with LLF scenario**



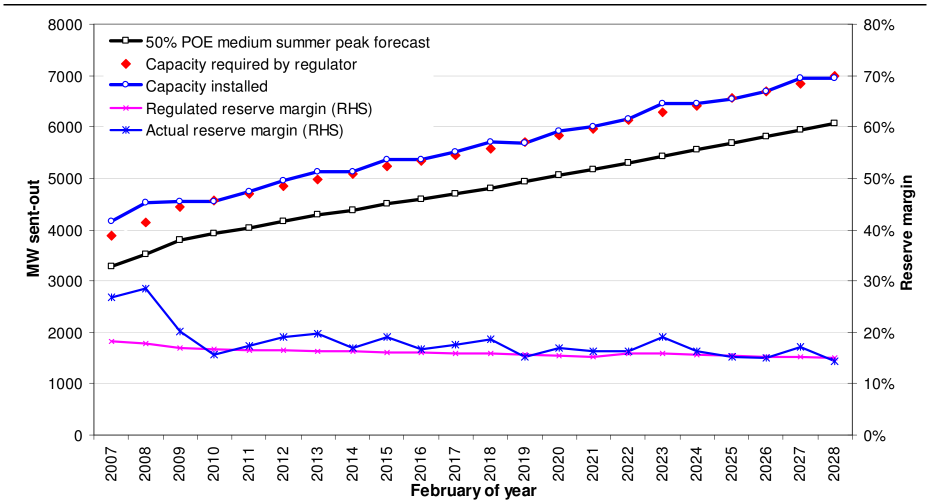
Data source: ACIL Tasman generator database

Figure 20 **Annual load-plant balance and reserve margin – SWGEN option with 2007LF scenario**



Data source: ACIL Tasman generator database

Figure 21 **Annual load-plant balance and reserve margin – METROGEN option with 2007LF scenario**

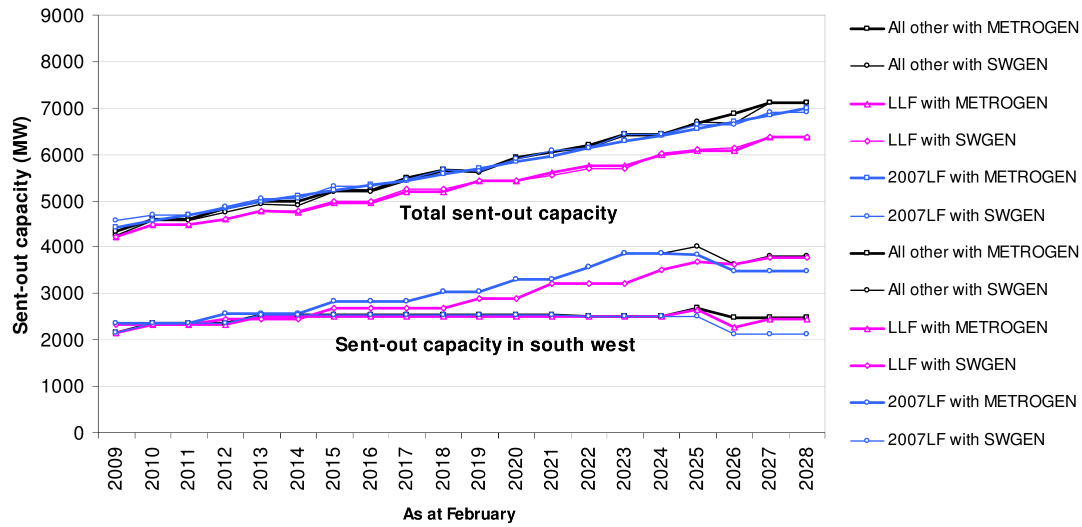


Data source: ACIL Tasman generator database

6.2.5 Sent-out capacity in the South West

The sent-out capacity in each of the generation options is shown in Figure 22. The overall sent-out capacity required under the expected IMO growth increases from around 4,200MW to around 7,100MW. The capacity in the South West region remains static at just over 2,500MW in the METROGEN option (assumes no South West transmission augmentation) whereas in the SWGEN option (assumes South West transmission goes ahead) the sent-out capacity increases to around 3,500MW.

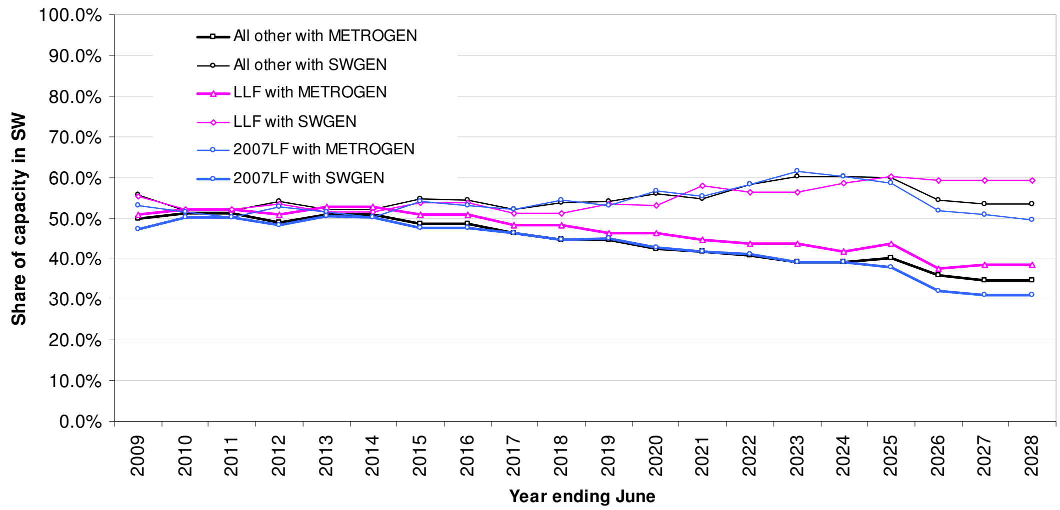
Figure 22 **Sent-out capacity overall and in the South West region**



Data source: ACIL Tasman generator database

The percentage share of sent-out capacity in the South West region is shown in Figure 23. Under the SWGEN options the South West region's share increases from around 50% in the initial years to around 60% by 2025. This compares with a decline in share from around 50% to around 35% by the end of the 20 year projection.

Figure 23 **Percentage share of sent-out capacity in the South West region**



Data source: ACIL Tasman generator database

6.2.6 Plant availability

Availability of plant is dependent on a number of factors including age of the plant, maintenance practices, weather and operating conditions. Plant outages in the modelling include major planned maintenance and unplanned outages (forced outages). The planned maintenance programs and forced outage rates have been set in the modelling based on experience and performance of similar plant in the NEM. Planned outages have been timed to ensure plant is available at peak times.

6.3 Short run marginal costs (SRMC)

The SRMC of plant is the stem offer price used of generators up to the contracted level and is used to allocate contracts to individual plants. The SRMC is the fuel cost plus variable operation and maintenance (O&M) costs. Variable O&M costs relate to costs which vary with a station's output. These costs generally relate to station consumables (such as water, ash disposal, chemicals etc) and any maintenance related to run-time. It does not include any allowances for periodic maintenance as these are captured within a separate annual fixed O&M figure.

The WEM is modelled on a nominal pricing/cost basis and assumes that variable operating and maintenance costs and fuel costs escalate over time, relative to an assumed CPI.

6.3.1 Fuel costs

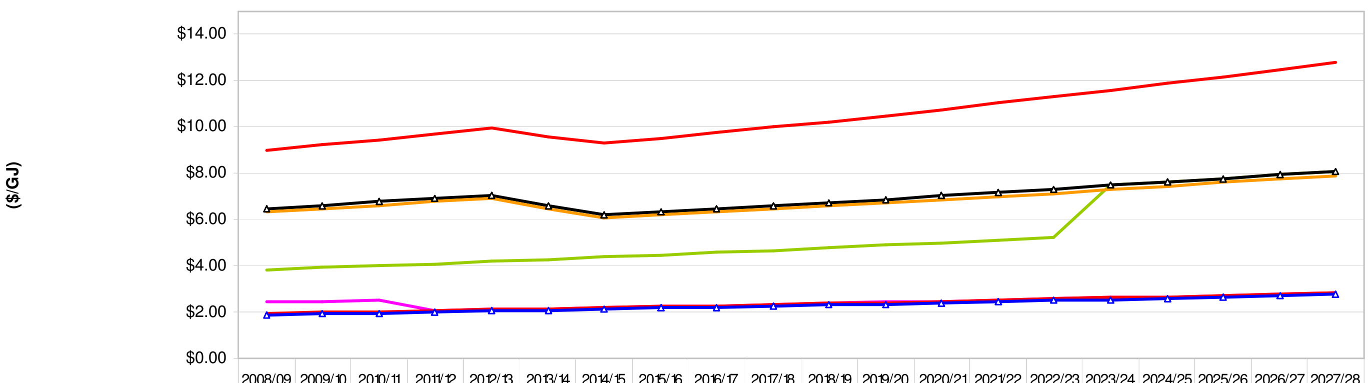
Fuel costs are more complex, in that they escalate at different rates and indeed, the escalation in some cases is not smooth – for example, reflecting step changes in the demand/supply balance of gas as well as changes (expiry and renewal) of coal contracts.

The projected delivered price of fuel used in generation in the WEM is shown in Figure 24. Coal is projected to remain the lowest cost fuel. The coal price also decreases in real terms, with an escalation rate of 80% of CPI.

The forward gas prices assume ex-field prices for gas of around $5.00/GJ until 2012/13 with ongoing supply constraints. It has been assumed that from 2013/14 a major new source of gas becomes available to the Western Australia domestic market and ex-field prices decline to around the $4.00/GJ level.

Prices into current plants were assumed to move onto this higher price level at the expiry of existing contracts or as price resets in existing gas supply contracts take effect. The assumptions relating to forward gas prices were based on a suite of gas market modelling scenarios performed by ACIL Tasman.

Figure 24 **Delivered fuel price projections (nominal $/MWh)**



	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28
Goldfields gas price	$9.00	$9.23	$9.46	$9.69	$9.93	$9.55	$9.28	$9.51	$9.75	$9.99	$10.24	$10.50	$10.76	$11.03	$11.31	$11.59	$11.88	$12.18	$12.48	$12.79
NewGen gas price	$3.83	$3.91	$4.00	$4.09	$4.18	$4.28	$4.37	$4.47	$4.57	$4.67	$4.78	$4.89	$5.00	$5.11	$5.22	$7.47	$7.63	$7.79	$7.95	$8.11
Gas - South of Perth	$6.49	$6.62	$6.76	$6.90	$7.05	$6.58	$6.21	$6.34	$6.47	$6.60	$6.74	$6.88	$7.03	$7.17	$7.32	$7.47	$7.63	$7.79	$7.95	$8.11
Gas - Perth	$6.36	$6.49	$6.63	$6.76	$6.90	$6.44	$6.06	$6.19	$6.31	$6.45	$6.58	$6.72	$6.86	$7.00	$7.14	$7.29	$7.44	$7.60	$7.76	$7.92
Wesfarmers/Griffin coal - Exist	$2.44	$2.48	$2.53	$2.07	$2.11	$2.15	$2.20	$2.24	$2.29	$2.33	$2.38	$2.43	$2.47	$2.52	$2.57	$2.63	$2.68	$2.73	$2.79	$2.84
Wesfarmers coal - new	$1.95	$1.99	$2.03	$2.07	$2.11	$2.15	$2.19	$2.24	$2.28	$2.33	$2.38	$2.42	$2.47	$2.52	$2.57	$2.62	$2.67	$2.73	$2.78	$2.84
Griffin coal - new	$1.89	$1.93	$1.97	$2.01	$2.05	$2.09	$2.13	$2.18	$2.22	$2.26	$2.31	$2.36	$2.40	$2.45	$2.50	$2.55	$2.60	$2.65	$2.71	$2.76

Data source: ACIL Tasman

The higher gas price used in the HGP scenario and the difference from the gas price is shown in Figure 4 on page 16.

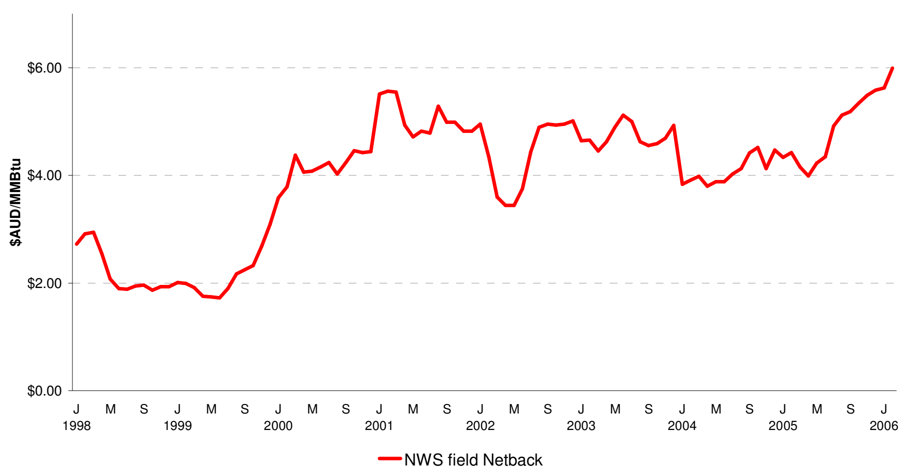
6.3.2 Gas pricing and the significance of LNG netback prices

Abundant competitively priced gas has underpinned Western Australia's rapid economic development and government expectations are high that this will continue into the future. There is a concern that these expectations will be undermined by the increasing gap between the netback price achieved through LNG sales to Japan and wider Asia Pacific markets versus gas sales to the domestic market.

Woodside's efforts in recent times to increase gas prices under existing contracts have been well-publicised, and it is clear that their current focus is on expanding LNG business which, under the prices currently being received in the international market (and expected to continue for some time), offer a higher net back value than domestic gas sales. So for example, in 2005–06 the Western Australia Department of Industry and Resources reported that total gas production for domestic purposes was 289 PJ at a total value of $703 million, implying an average ex-field price in the order of $2.44/GJ. The equivalent LNG netback sales price for the corresponding period ranged between $4 and $5/GJ after taking into account adjustments for LNG shipping, liquefaction and exchange rates. The netback price has subsequently risen further to around $6/GJ on the back of strengthening oil prices. As a result the NWSJV is currently arguing strongly for higher prices for domgas. Through 2007 the NWSJV has been indicating that it does not have uncommitted gas resources currently available for the domestic market.

Estimated LNG field netback price over the past eight years is shown in Figure 25.

Figure 25 **Estimated LNG field netback price, 1998 to 2006**



Data source: ACIL Tasman estimates, Westpac and Japanese official statistics

This position is reinforced by the strengthening public and political sentiment against coal: gas producers currently perceive that customers have very limited alternatives to paying the higher prices they are demanding. Other (non-NWS) producers will presumably be happy for Woodside to pursue this strategy. They will compete relative to the new price level as new domgas developments are brought on line, but will have no need or reason to bid prices down heavily provided a reasonably tight supply-demand balance is maintained.

The question is how high prices will be pushed. ACIL Tasman considers it unlikely that the producers will, in the mid to long term, push prices all the way to full export parity (notwithstanding that this objective will be commonly alluded to in negotiations). To do so would risk serious erosion of market demand and curtailment of growth opportunities. It would also be likely to elicit a strong supply side response, attracting new investment in exploration and production that would dilute the position of market dominance in which the NSWJV now finds itself. This is a view for which ACIL Tasman has received recent (May 2007) confirmation from a domestic market analyst within one of the major upstream participant companies in Western Australia.

Other factors supporting the argument for domgas rising to less than full export parity include:

- Domestic gas prices in Australia (both Western Australia and eastern states) have always demonstrated a significant level of price divergence, depending on market sector, load characteristics, customer's capacity to pay and alternative energy options.
- For a number of the competitive supply sources in Western Australia, directing gas into LNG manufacture is not an option generally because the resource is too small. So, for example, there is presently no means by which gas from Harriet or John Brookes or Perth Basin can access the international LNG market, and the prices prevailing there. For these sources, LNG is therefore not an alternative against which price can sensibly be set.
- In applications such as power generation and industrial steam raising, sustainable gas prices will be set by reference to the price of alternative fuels. In the absence of environmental policies that impose very high costs on coal use, this will generally mean that the price of coal will be influential on domestic gas pricing. There is clearly a government policy preference for fuels such as gas with lower emissions for gas over coal—but not at any price.
- In our view a price target of $4/GJ ex field (real 2007) would appear to be a reasonable mid to long term expectation. ACIL Tasman is aware that there have been recent spot sales, and offers for sale, considerably above that level. However, in our view this is a product of a very tight supply situation in which the holders of the only substantial uncontracted capacity

(Santos John Brookes) can afford to hold out for very high prices that can be achieved from remote area mining customers for which the alternative energy is liquid fuel.

Large scale greenfield domgas expansion appears to be some years off: Gorgon LNG, Pluto LNG (via associated developments), Wheatstone and Reindeer/Caribou all have potential to provide access to substantial quantities of domgas—but probably not for at least five years. However there is now some sign of emerging incremental supply through brownfield expansion. Specifically, Apache Corporation (which historically has provided the strongest competitive counterfoil for NWS domgas) has made a number of significant discoveries and developments that could bolster supply in the short to medium term:

- August 2006: Gnu-1 discovery, likely to be developed in conjunction with Reindeer & Caribou fields. Together these fields total >1tcf
- February 2007: Doric, Lee gas wells brought into production through the Harriet/Varanus Island facilities
- April 2007: Julimar-1 discovery tests at 85 MMSCFD, indications >1tcf reserves. Our market intelligence indicates that Apache is looking to fast-track development of Julimar field.

The recent announcement by BP and Rio Tinto of a feasibility study into a 500MW coal gasification/carbon sequestration project at Kwinana—with indicative costs suggesting a generation cost of around $70/MWh—serves as a reminder to gas producers that natural gas is not the only option for base load generation under carbon constraints.

Just where gas prices will settle, and how quickly, will depend on a range of factors: what happens with oil prices (and therefore LNG), how the prospects for new domgas supply (brownfield and greenfield) develop, what directions environmental policy takes and so forth. While a price rise to around $4 long term may dampen demand from some users such as the Alcoa cogeneration plants, gas producers are likely to find that in overall revenue terms the price increase will more than compensate for any erosion of demand. However, given the industry sectoral mix of gas demand in Western Australia, ACIL Tasman considers that a sustained push to very high prices of, say $6 to $7/GJ would lead to serious demand destruction and consequent value loss for producers.

6.4 New entrant costs

Table 2 details the assumptions used to calculate the new entrant cost of each technology. The nominal new entrant cost is calculated for each year of the projection period, hence the required assumptions about escalation of capital and other costs.

Table 2 **New entrant cost assumptions**

Input assumption	Cogen	Coal	CCGT	OCGT
Auxiliary Requirements	2.4%	6.8%	2.0%	0.5%
Thermal Efficiency (sent out)	34.1%	36.1%	44.0%	34.0%
Economic Life (years)	30	40	35	30
Capital cost (2008/09$ per kW)	$1500	$2000	$1400	$900
Capital cost escalation rate (annual as % of CPI)	90%	90%	90%	90%
Fixed O&M (2008/09 $/MW/year)	$42,000	$32,000	$23,000	$11,000
Fixed O&M escalation rate (annual as % of CPI)	90%	90%	90%	90%
Variable O&M (2008/09 $/MWh)	$0.00	$1.57	$2.86	$10.29
Variable O&M escalation rate (annual)	90%	90%	90%	90%

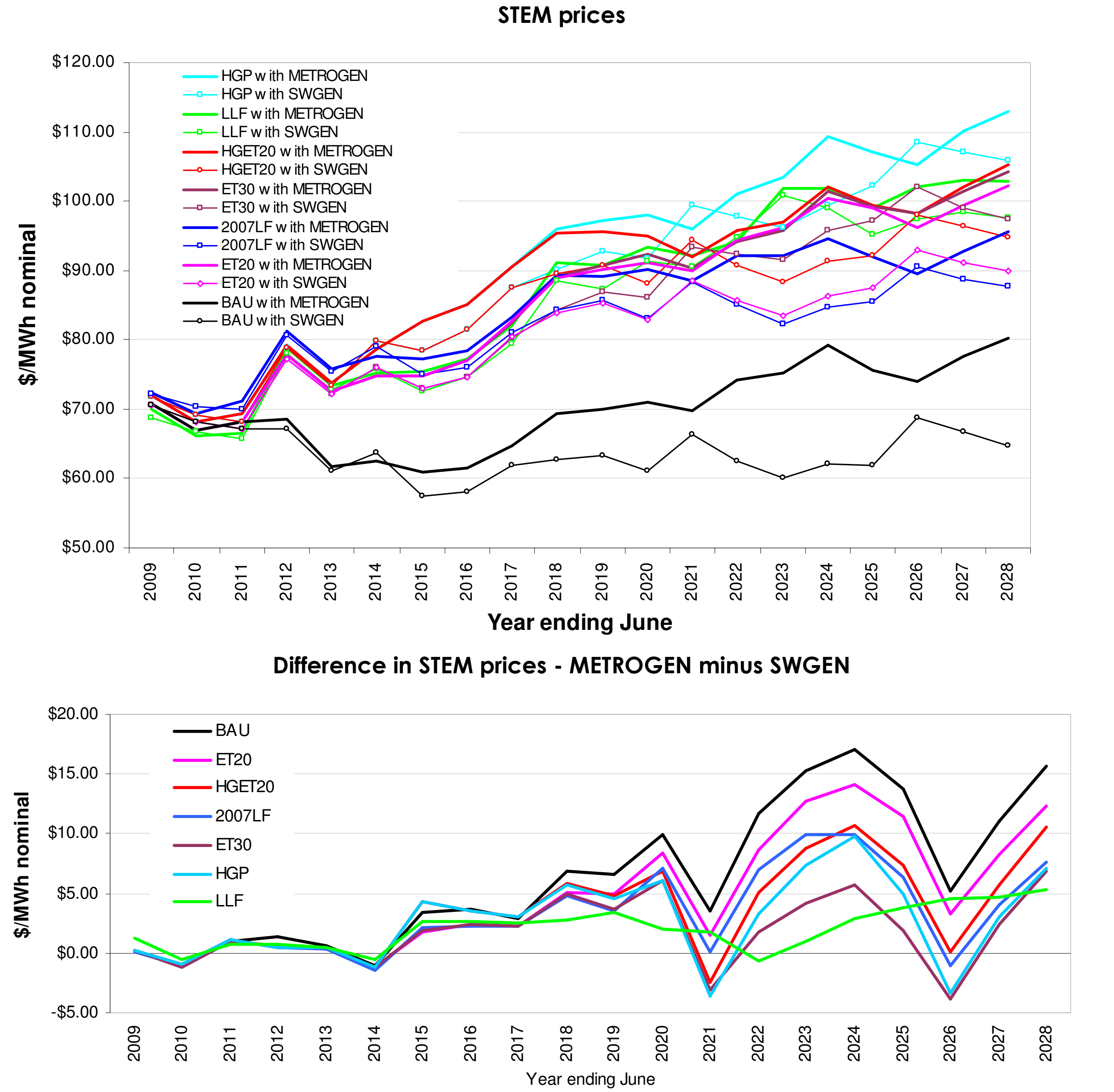
Data source: ACIL Tasman

7 Modelling results

7.1 STEM prices

The STEM prices for the 14 model runs are shown in Figure 26.

Figure 26 **Load weighted STEM price projection (nominal $/MWh)**



Data source: PowerMark WA modelling results

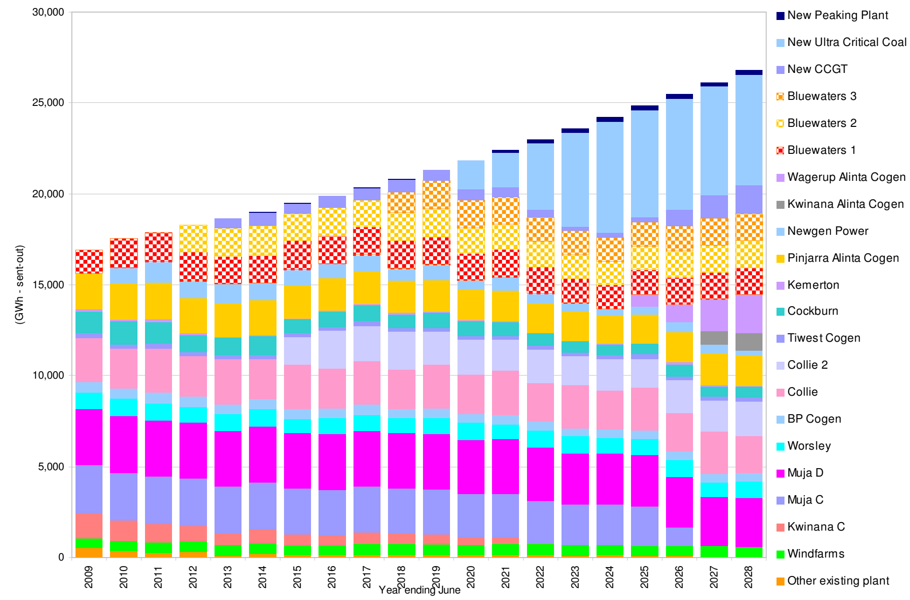
Figure 26 shows the nominal STEM price for the SWGEN is generally lower than for the METROGEN option. This is mainly because of the generally lower SRMC of the generation in the SWGEN option and the more diverse plant mix providing a more competitive market for generators in the SWGEN option.

The STEM prices for each of the seven market scenarios under the SWGEN option are noticeably lower than under the METROGEN option for all market scenarios. The differences only begin to show from around 2015 onwards as the additional low SRMC plant the South West region begin to have an effect. Surprisingly the lower STEM prices for SWGEN option occur for the ET30 and LLF scenarios.

7.2 Plant dispatch

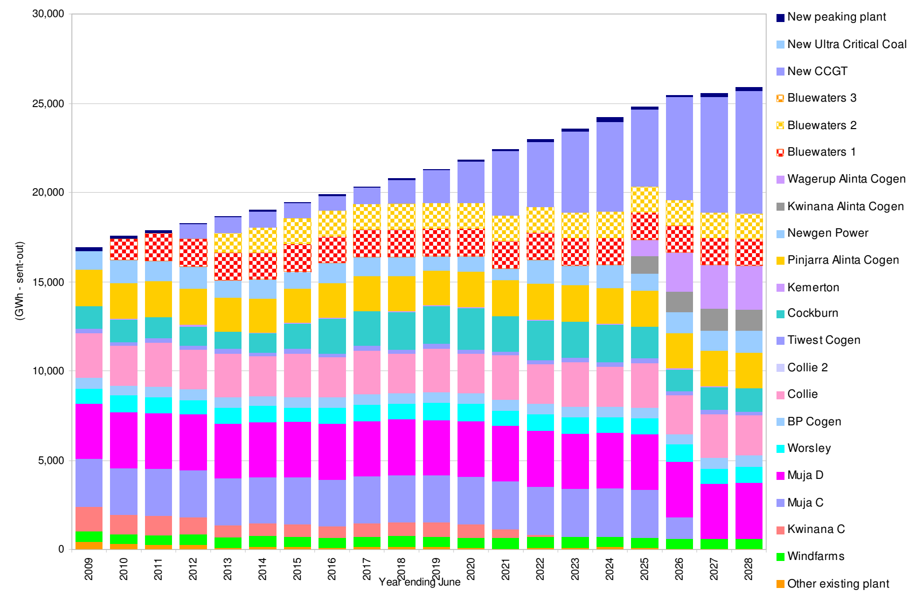
Plant dispatch under selected market scenarios and generation options are summarised in Figure 27 to Figure 32.

Figure 27 **Plant dispatch – SWGEN option with BAU scenario**



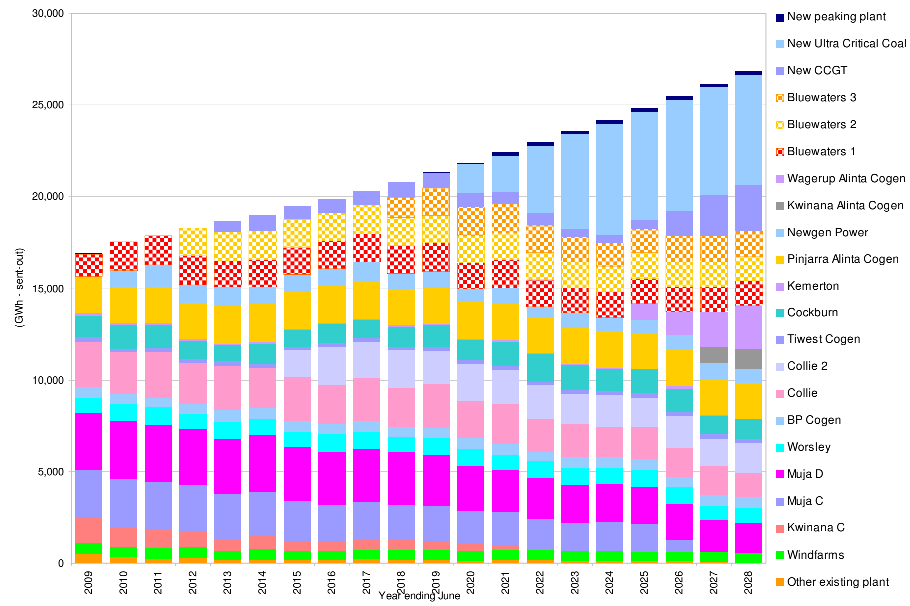
Data source: PowerMark WA modelling results

Figure 28 **Plant dispatch – METROGEN option with BAU scenario**



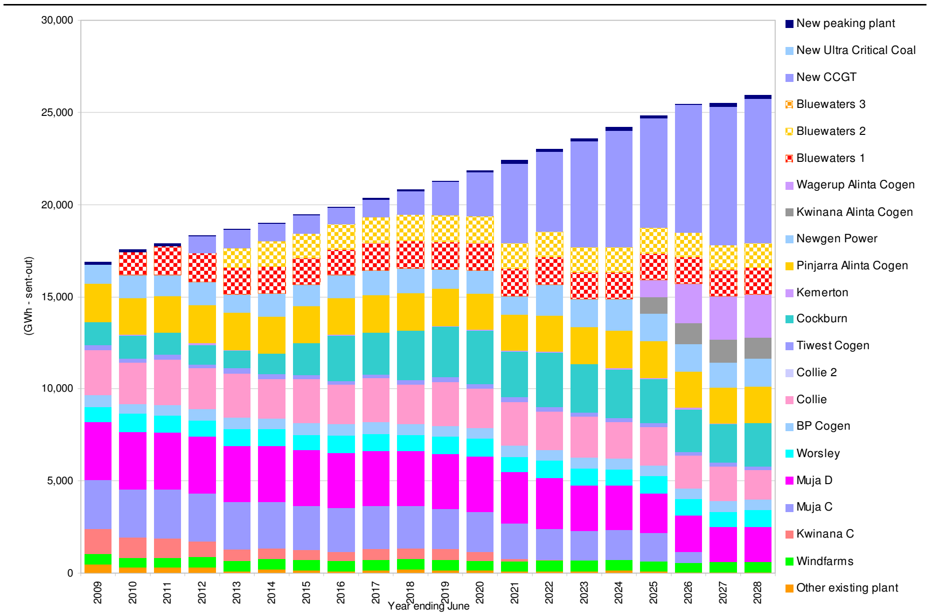
Data source: PowerMark WA modelling results

Figure 29 **Plant dispatch – SWGEN option with ET30 scenario**



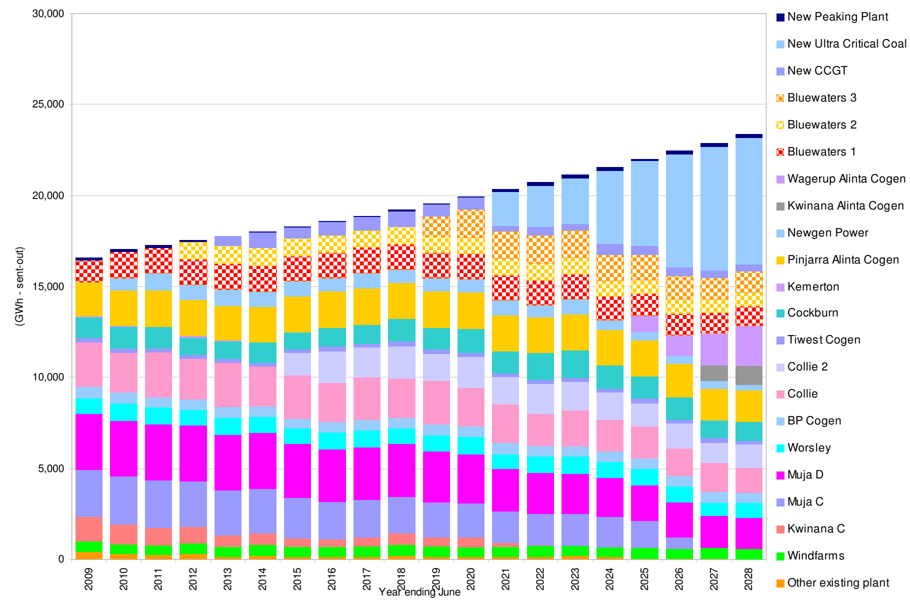
Data source: PowerMark WA modelling results

Figure 30 **Plant dispatch – METROGEN option with ET30 scenario**



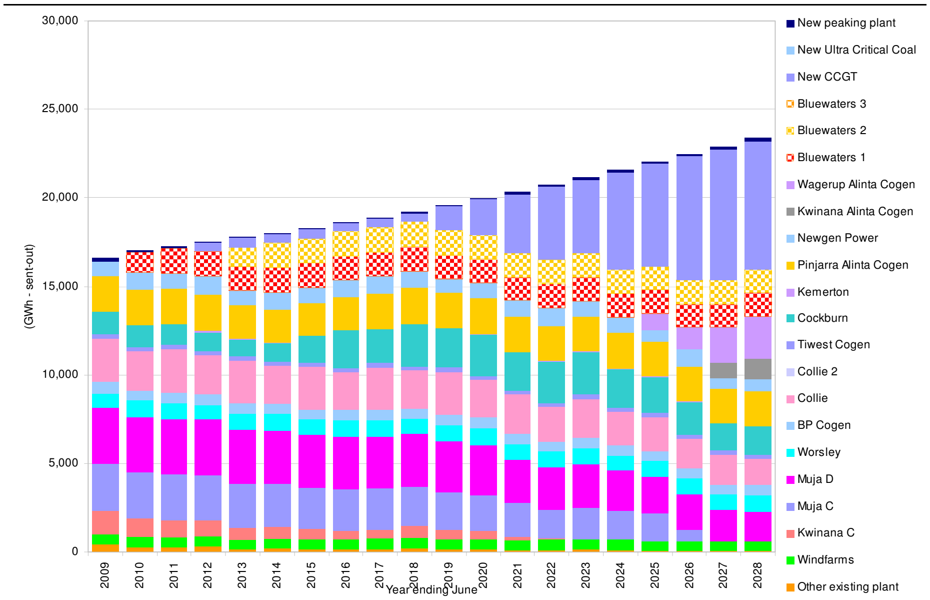
Data source: PowerMark WA modelling results

Figure 31 **Plant dispatch – SWGEN option with LLF scenario**



Data source: PowerMark WA modelling results

Figure 32 **Plant dispatch – METROGEN option with LLF scenario**



Data source: PowerMark WA modelling results

7.2.1 Gas used in generation

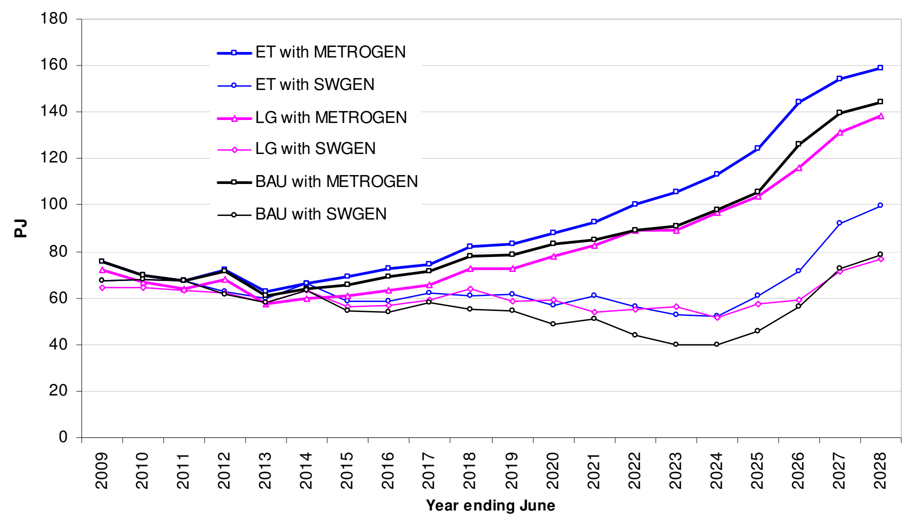
Gas used in electricity generation under selected market scenarios for the two generation options is shown in Figure 33. As expected it shows that gas consumption under the SWGEN option is significantly less than under the METROGEN option.

Under the SWGEN option gas consumption increases marginally from around 70PJ in 2009/10 to between 80PJ in the BAU and LLF scenarios to and 100PJ in the ET30 scenario by 2027/28.

Under the METROGEN option gas consumption increases noticeably from around 70PJ in 2009/10 to between 140PJ in the BAU and LLF scenarios and 160PJ in the ET30 scenario.

The increase in gas consumption over the 20 years between the SWGEN and METROGEN ranges from 437PJ in the LLF scenario to 596 in the BAU.

Figure 33 **Gas used in generation on the SWIS (PJ)**



Data source: PowerMark WA modelling results

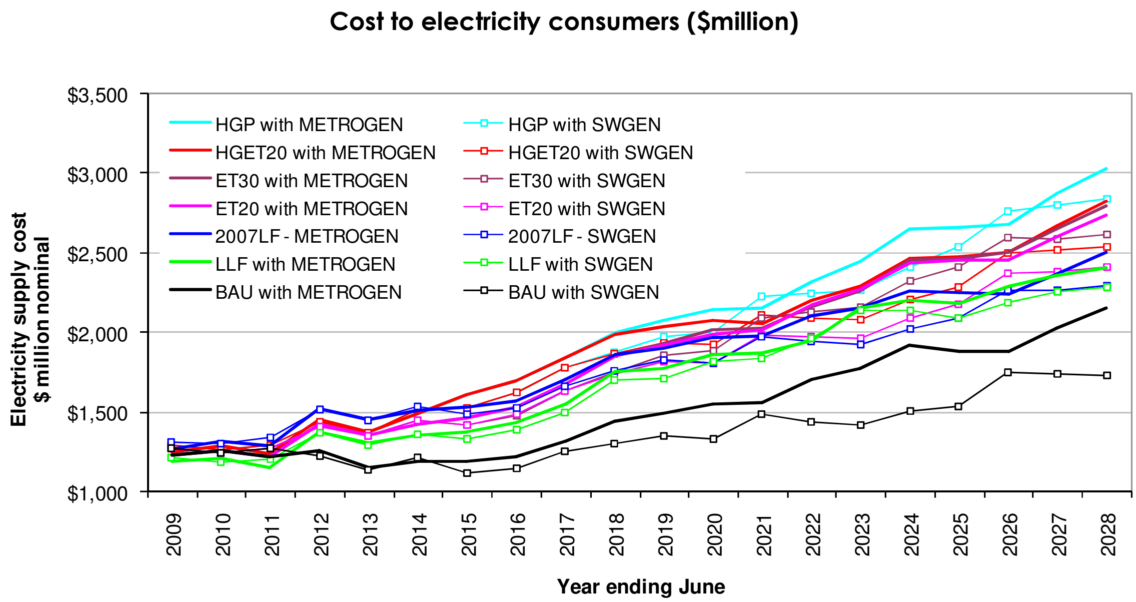
The increased gas consumption under the METROGEN option will require substantial increase in domestic gas production and pipeline capacity particularly beyond 2018. On the other hand gas consumption in the SWGEN option would not require additional domestic gas production or pipeline capacity until 2026/27.

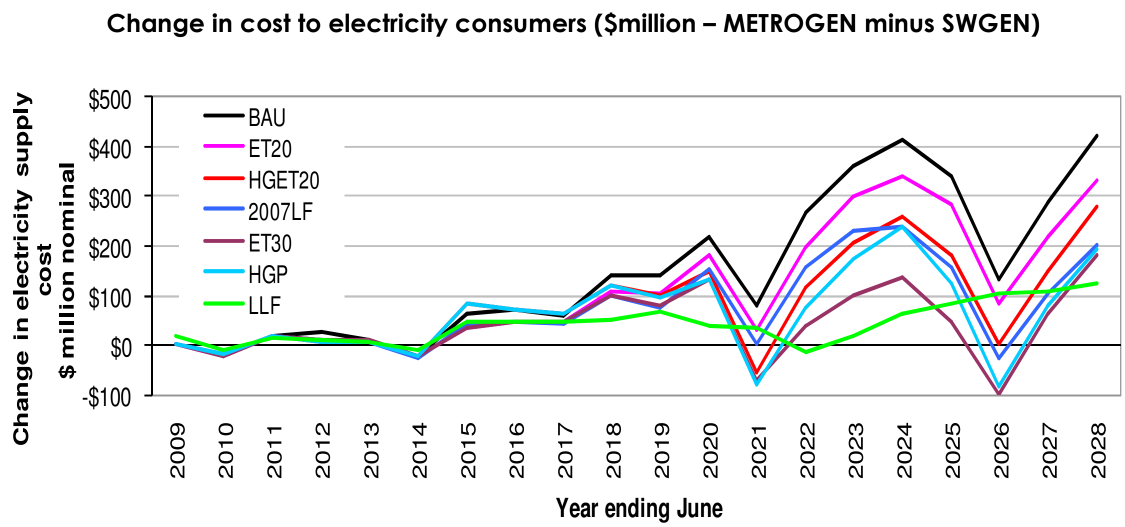
7.3 Cost of electricity to consumers

Assuming the capacity payments and refunds are the same per MWh under all market scenarios and generation options then the difference in the STEM purchase costs provide a good representation of the difference in wholesale electricity costs to the consumer. The cost of the south west transmission augmentation is added to wholesale STEM electricity costs under the SWGEN options but not to the METROGEN options. This is to reflect the additional network charges met by electricity users under the SWGEN options.

The differences in electricity supply costs (STEM plus transmission) between the two supply options (METROGEN minus SWGEN) under the various market scenarios are summarised in Figure 34. It shows that the SWGEN option is a lower cost option in most years in all market scenarios. However, as expected, the significant advantage of SWGEN option in the BAU scenario is substantially reduced with the addition of an emission trading regime given the greater reliance on low cost coal fired generation in the SWGEN option. It also shows that lower load growth impacts noticeably on the SWGEN advantage but not so much as to turn it negative.

Figure 34 **Cost to electricity consumers - STEM plus transmission METRO GEN minus SWGEN ($ million nominal)**





Data source: PowerMark WA modelling results

Key components of the net present cost of electricity to consumers are shown in Table 3. The table does not include the cost of capacity payments which are a feature of the WEM as these are unaffected by the proposed south west transmission augmentation. The network costs apart from the south west augmentation assumed under the SWGEN option and a small allowance for shared connections in the METROGEN option, are not included in the table as these are also assumed to be unaffected by the south west augmentation.

The table reveals that electricity consumers are better off with the south west transmission augmentation with the SWGEN option allowing lower cost generation to access the major load centres. This is the case under all market scenarios and discount factors.

Under the BAU the improvement in electricity supply costs is estimated at between 4.2 and 5.8%. Under the LLF scenario consumers are also better off. The modelling suggests that the ET30 scenario is the most marginal but still positive for electricity consumers.

Table 3 **Net present cost to consumers of electricity supply ($million NPV in 2007/08)**

Market scenario with generation option	Discount factor		
	10%	12.50%	15%
Energy purchase costs			
BAU with METROGEN	$11,643	$9,708	$8,247
BAU with SWGEN	$10,894	$9,157	$7,837
ET20 with METROGEN	$13,781	$11,368	$9,556
ET20 with SWGEN	$13,220	$10,960	$9,255
HGET20 with METROGEN	$14,314	$11,807	$9,923
HGET20 with SWGEN	$13,853	$11,462	$9,661
2007LF - METROGEN	$13,900	$11,533	$9,746
2007LF - SWGEN	$13,499	$11,236	$9,522
ET30 with METROGEN	$13,823	$11,397	$9,577
ET30 with SWGEN	$13,580	$11,211	$9,433
HGP with METROGEN	$14,618	$12,020	$10,074
HGP with SWGEN	$14,248	$11,738	$9,855
LLF with METROGEN	$12,931	$10,695	$9,012
LLF with SWGEN	$12,679	$10,499	$8,857
Cost of additional transmission			
METROGEN	$99	$95	$91
SWGEN	$166	$159	$152
Electricity supply costs			
BAU with METROGEN	$11,742	$9,803	$8,338
BAU with SWGEN	$11,059	$9,316	$7,989
ET20 with METROGEN	$13,880	$11,463	$9,648
ET20 with SWGEN	$13,386	$11,118	$9,408
HGET20 with METROGEN	$14,413	$11,902	$10,014
HGET20 with SWGEN	$14,019	$11,621	$9,813
2007LF - METROGEN	$13,999	$11,628	$9,837
2007LF - SWGEN	$13,665	$11,395	$9,675
ET30 with METROGEN	$13,922	$11,492	$9,668
ET30 with SWGEN	$13,745	$11,370	$9,586
HGP with METROGEN	$14,717	$12,115	$10,165
HGP with SWGEN	$14,414	$11,897	$10,008
LLF with METROGEN	$13,030	$10,790	$9,103
LLF with SWGEN	$12,845	$10,658	$9,010
Difference in electricity costs to consumers - METROGEN minus SWGEN			
$ million			
BAU	$682.48	$486.30	$348.69
ET20	$493.58	$344.17	$240.01
HGET20	$393.57	$280.94	$201.08
2007LF	$333.66	$233.38	$162.45
ET30	$176.64	$121.86	$82.47
HGP	$302.82	$218.13	$157.10
LLF	$184.31	$131.26	$93.62
Percentage			
BAU	5.8%	5.0%	4.2%
ET20	3.6%	3.0%	2.5%
HGET20	2.7%	2.4%	2.0%
2007LF	2.4%	2.0%	1.7%
ET30	1.3%	1.1%	0.9%
HGP	2.1%	1.8%	1.5%
LLF	1.4%	1.2%	1.0%

Note: The table does not include the cost of capacity payments or network costs apart from the south west augmentation.

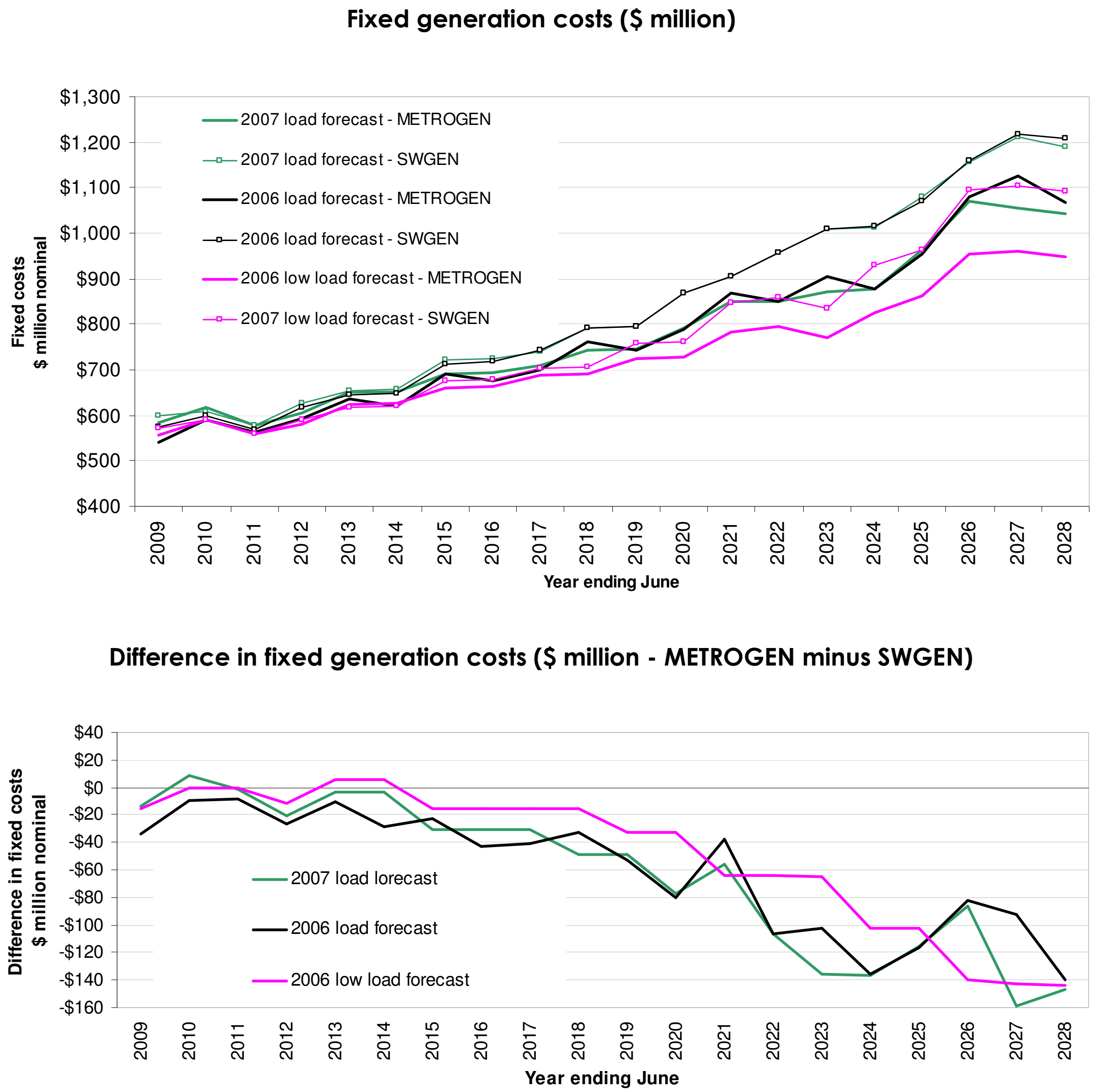
Data source: ACIL Tasman analysis based on *PowerMark WA* modelling results and information in the WPN south west transmission augmentation report.

7.4 Cost of generation

7.4.1 Fixed generation costs

The annual fixed costs of generation for the two generation options and the three different load forecasts are shown in Figure 35. The fixed costs of generation under the METROGEN option are generally lower than under the SWGEN option because of the capital cost of high efficiency coal fired plant under the SWGEN option is assumed to be $500/kW higher in 2007 terms than the CCGTs under the METROGEN option.

Figure 35 **Fixed generation costs for the two generation option and the three load forecasts**

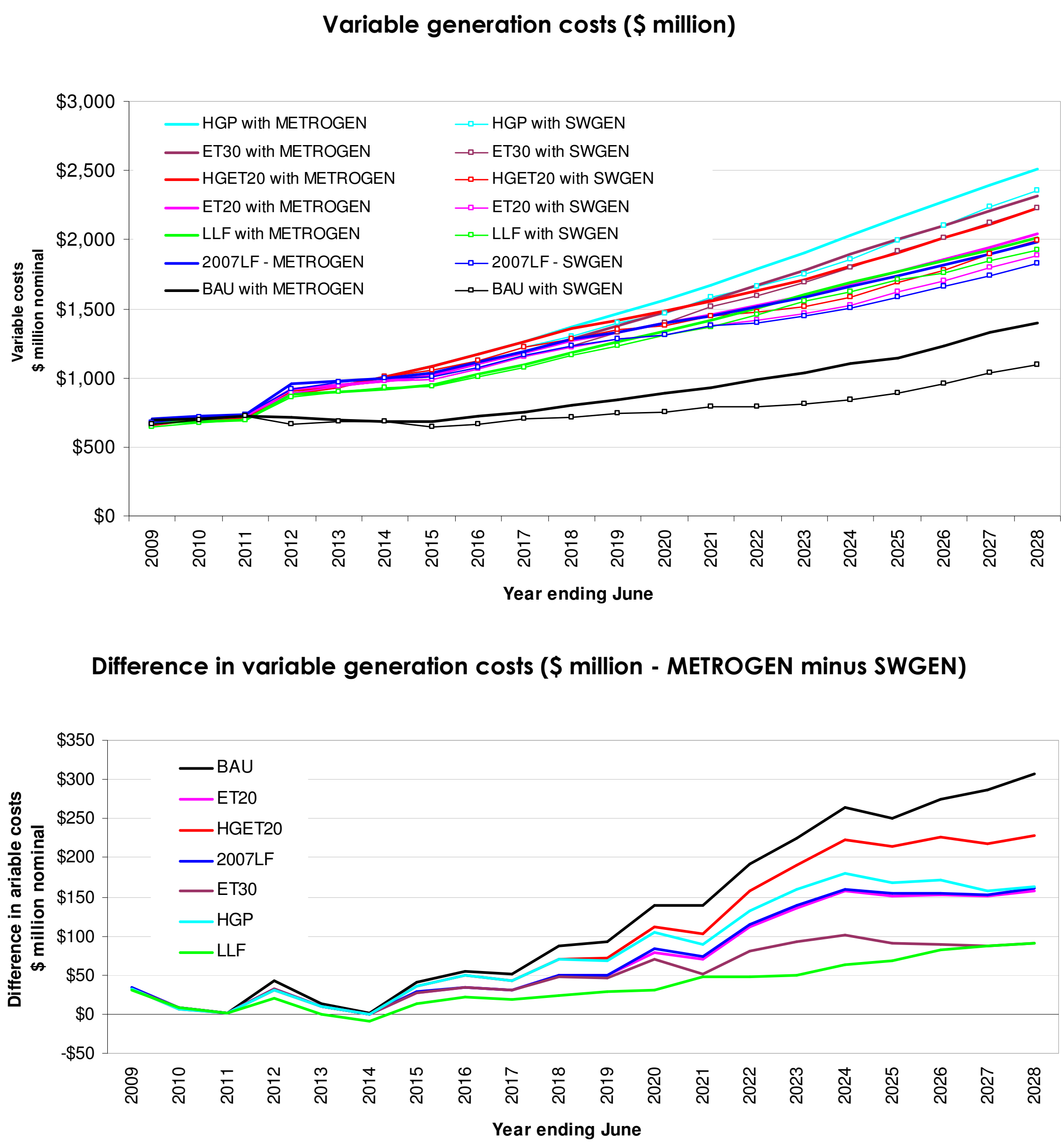


Data source: ACIL Tasman analysis based on *PowerMark WA* modelling results

7.4.2 Variable generation costs

The annual variable costs of generation for the two generation options and the seven market scenarios are shown in Figure 36. It shows that the variable costs of generation under the SWGEN option is generally lower than under the METROGEN option. This is because the variable cost of coal fired generation assumed at around $19.50 in the BAU in 2007 terms is substantially lower than gas fired CCGTs assumed at around $48.10/MWh.

Figure 36 **Variable generation costs for the two generation option and the seven market scenarios**

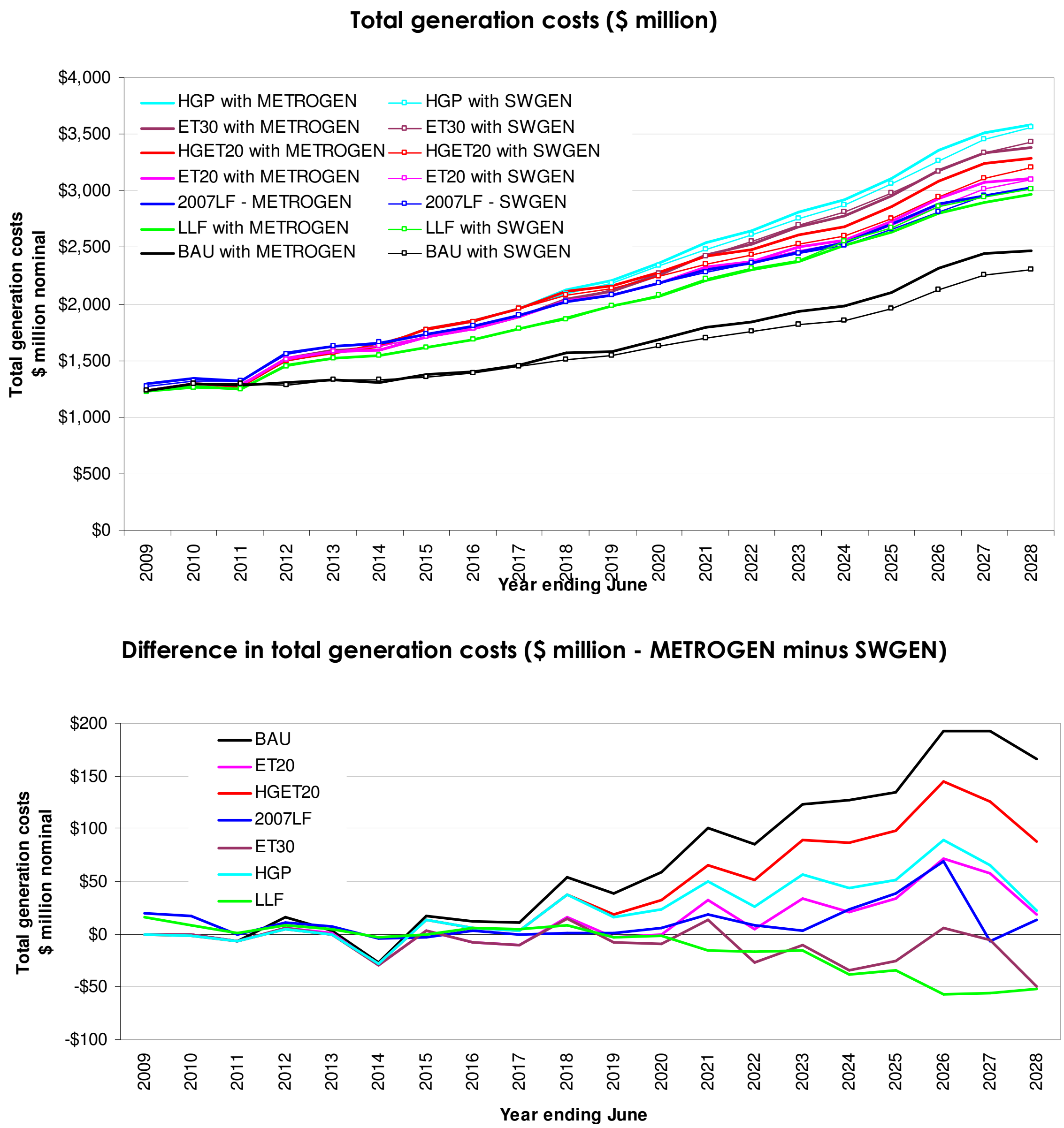


Data source: ACIL Tasman analysis based on *PowerMark WA* modelling results

7.4.3 Total generation costs

As shown in Figure 37, the total cost of generation is generally lower under the SWGEN option with the higher fixed costs of the coal plant being offset by the lower variable costs in all market scenarios except ET30 and LLF where the lower variable generation costs are not sufficient to offset the higher capital costs in the SWGEN option compared with the METROGEN option.

Figure 37 **Total generation costs for the two generation options and the seven market scenarios**

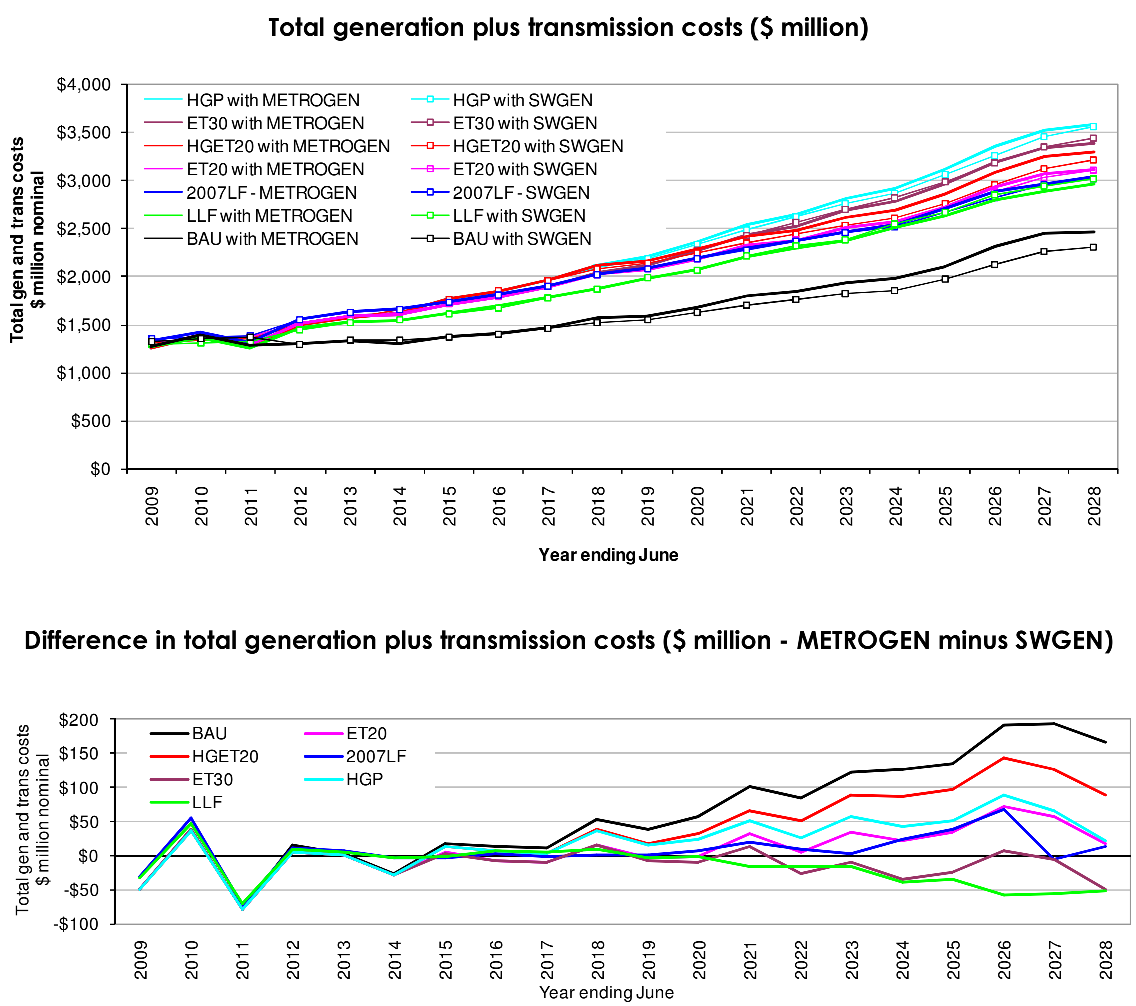


Data source: ACIL Tasman analysis based on *PowerMark WA* modelling results

7.4.4 Generation and transmission costs

When the cost of the south west transmission augmentation is added to the SWGEN option the result further increases the cost of this option compared with the METROGEN option as shown in Figure 38. It is the same as the total generation costs in Figure 37 except that the cost of the required transmission augmentations are added to the annual figures out to 2011/12.

Figure 38 **Total generation plus transmission costs for each generation option and market scenario**



Data source: ACIL Tasman analysis based on *PowerMark WA* modelling results

7.4.5 Summary of generation and transmission costs

Key components of the net present cost of supplying electricity are shown in Table 4.

Table 4 **Net present cost of generation and transmission over the period 2008/09 to 2027/28 ($million NPV in 2007/08)**

Market scenario with generation option	Discount factor		
	10%	12.50%	15%
Generation costs			
BAU with METROGEN	$12,778	$10,626	$9,004
BAU with SWGEN	$12,488	$10,419	$8,856
ET20 with METROGEN	$15,273	$12,571	$10,546
ET20 with SWGEN	$15,238	$12,552	$10,536
HGET20 with METROGEN	$15,672	$12,867	$10,767
HGET20 with SWGEN	$15,499	$12,747	$10,683
2007LF - METROGEN	$15,436	$12,738	$10,711
2007LF - SWGEN	$15,357	$12,673	$10,655
ET30 with METROGEN	$15,653	$12,837	$10,734
ET30 with SWGEN	$15,703	$12,877	$10,765
HGP with METROGEN	$16,079	$13,151	$10,967
HGP with SWGEN	$15,976	$13,079	$10,917
LLF with METROGEN	$14,676	$12,095	$10,159
LLF with SWGEN	$14,696	$12,100	$10,154
Transmission costs			
BAU with METROGEN	$99	$95	$91
BAU with SWGEN	$166	$159	$152
Generation and transmission costs			
BAU with METROGEN	$12,877	$10,721	$9,096
BAU with SWGEN	$12,654	$10,578	$9,008
ET20 with METROGEN	$15,371	$12,666	$10,637
ET20 with SWGEN	$15,404	$12,711	$10,688
HGET20 with METROGEN	$15,771	$12,962	$10,858
HGET20 with SWGEN	$15,665	$12,906	$10,835
2007LF - METROGEN	$15,534	$12,833	$10,802
2007LF - SWGEN	$15,523	$12,832	$10,808
ET30 with METROGEN	$15,751	$12,932	$10,826
ET30 with SWGEN	$15,869	$13,036	$10,918
HGP with METROGEN	$16,178	$13,246	$11,059
HGP with SWGEN	$16,142	$13,238	$11,070
LLF with METROGEN	$14,775	$12,190	$10,250
LLF with SWGEN	$14,862	$12,259	$10,306
Difference in generation and transmission costs METROGEN minus SWGEN			
$ million NPV in 2007/08			
BAU	$223	$142	$88
ET20	-$33	-$44	-$51
HGET20	$106	$56	$23
2007LF	$12	$1	-$5
ET30	-$118	-$103	-$92
HGP	$36	$8	-$11
LLF	-$87	-$69	-$56
Percentage			
BAU	1.7%	1.3%	1.0%
ET20	-0.2%	-0.3%	-0.5%
HGET20	0.7%	0.4%	0.2%
2007LF	0.1%	0.0%	0.0%
ET30	-0.7%	-0.8%	-0.8%
HGP	0.2%	0.1%	-0.1%
LLF	-0.6%	-0.6%	-0.5%

Data source: ACIL Tasman analysis based on *PowerMark WA* modelling results and information in the WPN south west transmission augmentation report.

Table 4 reveals that the net present cost of generation plus transmission under the BAU scenario is lower for the SWGEN option than for the METROGEN option by between $88 million and $223 million or between 1.0% and 1.7%.

The net present cost of generation plus transmission is higher in the SWGEN options when emissions trading is applied and when load growth is low. However a $20.00/tCO2e emissions trading price, when taken with either high gas prices or the higher 2007 IMO load forecast, shows the SWGEN option to have lower net present costs than the METROGEN option.

In those scenarios where the net present costs of the SWGEN option is higher than the METROGEN option, the difference is less than 0.8% and given the uncertainty contained in the modelling assumptions, this is too small an amount to be interpreted as indicating that the SWGEN is a more costly option for generators.

The major sources of possible variability include:

capital cost of generating plant – a smaller difference between the capital cost of coal plant and CCGTs would assist the SWGEN option.

fuel costs, particularly gas – higher gas prices assist the SWGEN option as seen by comparing ET30 and HGP scenarios and the ET20 and HGET20 scenarios in Table 4 where the higher gas price from 2014 improves the position of the SWGEN option by around $150 million at the 10% discount level.

load forecast – comparing ET30 and LLF in Table 4 suggests that a generally lower forecast is beneficial for the SWGEN option because the lower cost of generation in the south west region forms a greater proportion of overall generation. Moving from the 2006 forecast to the 2007 forecast, which is higher in the initial years and slightly lower in the latter years, results in an advantage to the SWGEN option of $45 million in net present terms (compare ET20 with 2007LF in Table 4).

future emissions trading arrangements – the price for emissions is a critical assumption with higher prices disadvantaging the SWGEN option. Moving from an emissions price cap of $20/tCO2e (triggered from 2018) to a cap of $30/tCO2e disadvantages the SWGEN option by $85 million in 2007/08 present value terms using 10% discount. (compare ET20 to ET30 in Table 4)

discount rate – apart from the LLF scenario higher discount rates disadvantage the SWGEN option.

7.5 Comment on electricity and generation costs

The modelling suggests that while the cost of electricity to consumers is lower for the SWGEN in all scenarios the cost of generation plus transmission is generally slightly higher under the SWGEN option when emissions trading is incorporated with the 2006 IMO forecast or there is low load growth. It suggests that generator competition is enhanced under the SWGEN option because, while generation and transmission costs may be slightly higher under some scenarios, the option delivers lower prices to consumers than the METROGEN option under all scenarios.

Even if it is accepted that generation plus transmission costs are slightly higher under the SWGEN option under the emission trading with the 2006 IMO load forecast and low load growth scenarios, it does not mean that generators are not achieving a reasonable market return under these scenarios. In fact generators, particularly existing coal fired generators, are likely to be earning above normal market returns under the METROGEN option where competition is less because the entry of low cost coal fired generation is constrained by lack of transmission.

The analysis assumes that the cost of capacity, being generally set by the IMO, would be the same in all market scenarios and generation options and those variations in the STEM price provide a measure of the likely movement in bilateral contract prices between generators and retailers and to the ultimate electricity costs to consumers. The reason that the STEM prices are lower in all scenarios under the SWGEN option (see Figure 26) is the generally lower SRMC for generators in SWGEN option.

In reality, base load generators will be seeking to cover the costs of generation in any bilateral contracts with retailers and while the STEM price implies a lower cost to consumers, it is the bilateral contract prices which is the cost ultimately covered by consumers. That said a retailer always has the option of purchasing energy out of the STEM and capacity from the IMO at the going price. In turn, this will provide significant discipline on the bilateral contract prices.

7.6 Conclusions on generation options

The south west transmission augmentation will allow further development of gas fired cogeneration associated with alumina plants in the South West region and the development of additional coal fired capacity at Collie. Without the augmentation additional generation to replace retired plant and cater for load growth would need to be in the form of CCGTs located near to the major load centres.

The new plant in the South West region under the SWGEN option have noticeably lower SRMC but higher capital cost than gas fired CCGTs in the METROGEN option. The recent increase in gas prices exaggerates the SRMC advantage of coal fired plant in the SWGEN option. The lower SRMC produces lower STEM prices in a more competitive market under the SWGEN option. This is why the estimated cost of electricity to consumers is lower under the SWGEN option in all market scenarios.

Generation plus transmission costs are noticeably lower for the SWGEN option in most scenarios except those with emissions trading with the 2006 load forecast or low load forecast. But when a $20/tCO2e emission trading is included with either a higher gas price or the 2007 load forecast, the modelling suggests that the generation plus transmission costs are slightly lower for the SWGEN option. However the difference in generation plus transmission costs is never more than 0.8% which is well within the uncertainties in the modelling assumptions. On this basis, the findings on generation plus transmission costs are inconclusive and should not be used to directly influence the decision on whether or not to proceed with the south west transmission augmentation. It does not necessarily mean that generators are not achieving reasonable market returns under the SWGEN option and emission trading scenarios and low load growth.

Finally, the projected gas use in the METROGEN option would require substantial expansion in domestic gas production and pipeline capacity from around 2017/18. The gas use projection suggests that an expansion in domestic gas production and pipeline capacity would not be required under the SWGEN option until 2026/07.

Enhanced transmission to the South West will also provide for increased renewable generation in the region thus providing more options for potential large scale renewable generation.

8 Option evaluation

Western Power advised that if sufficient new generation is established within the Perth metropolitan area, the need to increase the capacity of South West to Perth transmission would be reduced and possibly even completely alleviated. The model results suggest, however, that the benefits in terms of minimising total system cost is at best marginal and likely to substantially diminish the benefit to consumers.

Thus, in the absence of a compelling economic case against augmenting the capacity of the South West transmission line, we now consider the network and non-network options as proposed by Western Power.

8.1 Network options

Western Power originally developed a total of seven network options to augment the SWIS with increased South West transmission capacity. An additional option (Option 8) was added in response to Western Power's public consultation. These options are summarised in Table 5. In technical terms, Western Power had originally identified Option 6 as the preferred option as this provides the highest reactive margin, the lowest transmission losses and the shortest transmission voltage recovery time for serious 330kV outages. This option also offers improved security of supply to Wells Terminal and the Boddington Gold Mine. After the public consultation process, Western Power developed Option 8, which meets the changes requested during public consultation and matches the technical performance of Option 6. In financial terms, Option 8 is more costly, although it is less costly than Option 4 once line losses are accounted for.

Option 1 is the main alternative to Option 8 and performs well in terms of reactive reserve margin, transmission network losses and transmission voltage recovery. It has, however, a higher net present cost than Option 8, even before taking line losses into consideration.

Except for Option 6, Option 7 and Option 8, all options are variations to Option 1. Before taking line losses into account (which are valued at $50/MWh), Option 4 is the least costly by $4.7M, with the next least costly option being Option 8. Note that changing the constant price of $50/MWh to an alternative positive number would not change the rank net present cost ordering of the options.[14]

Table 5 **Net present cost of network reinforcement options**

Option	Description	NPC over 5 years (millions of dollars)
1	Establish a new 330kV double circuit transmission line between Landwehr Terminal and South East Terminal	156.3
2	Establish a new 330kV switchyard at South East Terminal and cut the Shotts to Southern Terminal/Oakley 330kV transmission line into Landwehr Terminal	149.5
3	Establish a new 330kV switchyard at South East Terminal and install additional high voltage capacitor banks at South East Terminal and Guildford Terminal	152.2
4	Install a +200/100MVAr SVC at Northern Terminal then construct LWT-SET	151.4
5	Install series compensation in the 330kV bulk transmission lines between south-west generation sources and the Perth metropolitan area	230.2
6	Establish a second 330kV transmission line between Shotts Terminal and Wells Terminal and establish a new 330kV transmission line between Wells Terminal and Eastern Terminal [Note: Option 6 is no longer feasible]	138.2
7	Install a +200/100MVAr SVC at Northern Terminal then construct WLT-ET	149.1
8	Establish a 330 kV double circuit transmission line from Collie and tee-in into existing 330 kV transmission lines, and establish South East Terminal	141.5

Note: NPC denotes Net Present Cost. Estimated cost includes line losses and is discounted using a pre-tax rate of 10.05%.

Note: Option 8 has been added in this revised report.

Data source: Western Power, *Proposed Major Augmentation to the Electricity Network, 330kV Transmission Line to Support Electricity Load in the Perth Metropolitan Area*, May 2007.

Noting that Option 6 is no longer feasible given the shortened time frame to completion, inspection of Table 5 indicates that Option 8 is the least expensive option available. Therefore, given our interpretation of net benefit, Option 8 is the preferred option.

[14] While permitting the price of electricity to vary over the relevant time horizon may change the rank net present cost ordering, it is considered that this is unlikely to have a material impact. Common sense rules out prices that are equal to, or less than zero.

8.2 Non-network alternatives

8.2.1 Demand side management

Demand side management (DSM) is defined under the market rules as follows:[15]

> **Demand Side Management**: A type of capacity held in respect of a Facility connected to the SWIS; specifically, the capability of a Facility connected to the SWIS to reduce its consumption of electricity through the SWIS, as measured at the connection point of the Facility to the SWIS.
>
> **Demand Side Programme**: Means a programme under which a Market Customer contracts Loads to be available for curtailment upon request of the Market Customer or System Management.

Demand side management as defined above relates to curtailable loads.

DSM curtailable loads of 128 MW have been included in the existing available capacity in 2007 IMOWA Statement of Opportunities as being available through to 2016/17. Overall, it is estimated the SWIS could support a total of 205 MW of DSM curtailable load in 2009/10, without cutting into energy supply in non-peak times.[16]

Our expectations are that DSM capacity may grow marginally between now and 2010/11, perhaps by 20 MW at the most. Increased DSM capacity of this order will not offset the growth in maximum demand to any significant extent. Furthermore, a significant component in DSM capacity is located in the South West. New DSM will therefore do little to alleviate the need for augmentation from the South West to the Perth metropolitan region.

8.2.2 Reactive support from existing generators

As part of its responsibility for maintaining network stability, Western Power is required to control the level of reactive power in the SWIS. Box 1 explains reactive power and why, at the margin, it can be considered as an alternative to transmission augmentation.

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15 Independent Market Operator of Western Australia 2007, Electricity Industry (Wholesale Electricity Market) Regulations 2004, Consolidated Clean Version of the Market Rules, www.imowa.com.au .

16 Independent Market Operator of Western Australia 2007, op. cit., pp 28.

Box 1 **Reactive power and its consequences**

In order to understand this option, it is necessary to have an appreciation of what reactive power is and why it is important to control. The following explanation is sourced from David Eromon and John Kueck (2005):

"…On an alternating-current (AC) power system, voltage is controlled by managing production and absorption of reactive power. There are three reasons why it is necessary to manage reactive power and control voltage. First, both customer and power-system equipment are designed to operate within a range of voltages, usually within ±5% of the nominal voltage. At low voltages, many types of equipment perform poorly; light bulbs provide less illumination, induction motors can overheat and be damaged, and some electronic equipment will not operate at all (EPRI TR-111490 1998 and Florida Reliability 1996). High voltages can damage equipment and shorten their lifetimes. Second, reactive power consumes transmission and generation resources. To maximize the amount of real power that can be transferred across a congested transmission interface, reactive-power flows must be minimized. Similarly, reactive-power production can limit a generator's real-power capability. Third, moving reactive power on the transmission system incurs real-power losses. Both capacity and energy must be supplied to replace these losses. Voltage control is complicated by two additional factors. First, the transmission system itself is a nonlinear consumer of reactive power, depending on system loading. At very light loading the system generates reactive power that must be absorbed, while at heavy loading the system consumes a large amount of reactive power that must be replaced. The system's reactive-power requirements also depend on the generation and transmission configuration. Consequently, system reactive requirements vary in time as load levels and load and generation patterns change…

"… Injecting reactive power into the system raises voltages, and absorbing reactive power lowers voltages. Voltage-support requirements are a function of the locations and magnitudes of generator outputs and customer loads and of the configuration of the … transmission system. These requirements can differ substantially from location to location and can change rapidly as the location and magnitude of generation and load change. At very low levels of system load, transmission lines act as capacitors and increase voltages. At high levels of load, however, transmission lines absorb reactive power and thereby lower voltages. Most transmission-system equipment (e.g., capacitors, inductors, and tap-changing transformers) is static but can be switched [on or off] to respond to changes in voltage-support requirements…"

Source: David Eromon and John Kueck, Distributed Energy Resource (DER) Using FACTS, STATCOM, SVC, and Synchronous condensers for Dynamic Systems Control of VAR, Presented at 2005 National Association of Industrial Technology (NAIT) Convention St. Louis, Mo November 16-19, 2005.

The choices that Western Power has considered are:

1. Given high levels of system load, produce reactive power by using generators as synchronous compensators which, once run up to speed and synchronised to the system, can be declutched from their turbine to provide reactive power without producing real power.[17]
2. Augment the system with additional transmission lines to reduce system load and the absorption of reactive power, thereby reducing the need for generators to operate as synchronous compensators.

Western Power advises that with the retirement of 400MW of generation at Kwinana, together with the operation of more efficient generating plant remote from the metropolitan area, reactive support from local generation is

[17] The National Grid Company plc, *An Introduction to Reactive Power,* [URL: http://www.nationalgrid.com/NR/rdonlyres/43892106-1CC7-4BEF-A434-7359F155092B/3543/Reactive_Introduction_oct01.pdf].

expected to diminish in the future. A number of generators at Pinjar have the capability to operate as synchronous compensators, i.e. they are able to provide reactive power to the network even while they are not producing real power (and using fuel).

There is also the possibility that additional generating units at Pinjar could be fitted with the capability to operate as a synchronous compensator. Western Power advises that, in terms of deferring the need for network augmentation, this option is ineffective. Western Power's opinion is supported by SKM analysis.[18]

Table 6 provides a summary of Western Power's past and planned reactive power network reinforcements. The large number of reactive power installations (16) in a relatively short period (December 2005 to October 2008) suggests that Western Power has pursued this option up to its technical limit.

Table 6 **Network reinforcement: reactive power installations**

Commissioning Date	Location	Reinforcement	Driver
Dec 2005	Northern Load Areas	Install 180MVAr of capacitor banks	To provide reactive support to the network to avoid potential system voltage collapse following the connection of new generation at Alinta Pinjarra, Emu Downs and Walkaway.
Dec 2005	KEM-KW 91	Establish a new 330kV transmission line by stringing spare circuit	To alleviate the effect of the worst-case 330kV line outages that could cause system voltage collapse following the connection of new generation at Kemerton.
Dec 2005	Northern Terminal	Install a 90MVAr capacitor bank and expand 2 existing capacitor banks from 65MVAr to 90MVAr	To provide reactive support to the network to avoid potential system voltage collapse following the connection of new generation at Kemerton.
Dec 2005	Guildford Terminal	Establish a 330/132kV terminal station	To provide 330/132kV transformer capacity to accommodate new generation connecting to the 330kV network at Kemerton
Dec 2005	Guildford Terminal	Install a 60MVAr capacitor bank	To provide reactive support to the network to avoid potential system voltage collapse following the connection of new generation at Kemerton.
Oct 2006	Guildford Terminal	Convert the 330kV tee connection to a cut-in	To alleviate the effect of the worst-case 330kV line outages that could cause system voltage collapse following the connection of new generation Alinta 2 at Pinjarra.
Oct 2006	Kenwick Link	Establish a 330/132kV transformer station	To provide additional transformation capacity between 330kV and 132kV network that is required to accommodate additional 330kV generation Alinta 2 at Pinjarra.
Oct 2006	Pinjar	Modify 3 x Frame 6 Gas Turbines to operate as synchronous compensators	To provide reactive support to network for 330kV line outages. Require due to additional 330kV network loading and displacement of Pinjar generation that results from the connection of new generation Alinta 2 at Pinjarra.
Oct 2006	Southern Load Areas	Install 75MVAr of capacitor banks	To provide reactive support to the network to avoid potential system voltage collapse following the connection of new generation Alinta 2 at Pinjarra.

[18] See Sinclair Knight Merz, *Proposed New Large Network Asset for Reinforcement of the Electricity Supply to the Perth Metropolitan Area, Due Diligence Review of 330KV Augmentation Studies*, V1.1, 4 September 2007

Commissioning Date	Location	Reinforcement	Driver
Oct 2007	Southern Terminal	Expand CAP 81 from 45 to 90MVAr	To provide reactive support to the network to avoid potential system voltage collapse following the connection of new generation to the 330kV network.
Oct 2007	SHO-KEM 91	Establish a new 330kV transmission line by stringing spare circuit	To alleviate the effect of the worst-case 330kV line outages that could cause system voltage collapse following the connection of new generation in the south-west.
Oct 2007	Various Sites	Install 40MVAr of capacitor banks in zone substations.	To provide reactive support to the network to avoid potential system voltage collapse following the connection of new generation in the south-west.
Oct 2007	Southern Terminal	Install a 90MVAr capacitor bank	To provide reactive support to the network for 330kV line outages. (Note this project to be completed by Oct 2007 to provide some support for the network as the SVC project could not be completed on time).
Oct 2008	Southern Terminal	Install a 200MVAr SVC	To provide reactive support to network for 330kV line outages due to additional 330kV network loading from the connection of new generation in the south-west and retirement of Kwinana 132kV generation. Note this project was required by Oct 2007, but could not be delivered on time. The 90MVAr capacitor bank will be installed at Southern Terminal as an interim measure.
Oct 2008	Neerabup Terminal	Establish a new 330/132kV terminal station	To provide additional transformation capacity between 330kV and 132kV network that is required to accommodate additional 330kV generation connected as part of PPP2 and the retirement of the Kwinana 132kV generation plant.
Oct 2008	Southern Terminal	Install the 3rd 330/132kV transformer and a set of 132kV fault limiting series reactors	To provide additional transformation capacity between 330kV and 132kV network that is required to accommodate additional 330kV generation connected as part of PPP2 and the retirement of the Kwinana 132kV generation plant. The reactors are required to alleviate increased fault levels that result from this new transformer.

Source: Western Power

9 Qualitative factors in support of network augmentation

9.1.1 Connectivity of alternative electricity generators as an additional justification for network augmentation

Thus far, this evaluation has been largely concerned with the location of coal- and gas-fired electricity generators. This reflects the contemporary composition of capacity credits in which fuel types other than coal and gas account for just 5% of current capacity.[19] It may, however, be reasonable to expect that over time, the contribution of alternative fuel types (e.g. biomass and wind power) may account for progressively higher proportions of capacity in coming years.

This is reflected in the IMO's low load growth forecast, which among other things accounts for the impact of renewable and reduced emission generation

[19] Independent Market Operator, *2007 Statement of Opportunities Report*, July 2007.

technologies. However, this load projection is independent of location. In looking at existing and likely unconventional generation technologies (e.g. biomass and wind power) it is apparent that these generation options are likely to be located in the South West.

Thus, the transmission capacity could potentially play a part in a mix of incentives. That is, increased regional transmission capacity may encourage larger investment in renewable energy. While it is unclear to what extent the current network augmentation proposal would stimulate increased investment, it is fair to say that it would reduce the impediment to bringing on substantial new sources of renewable and alternative energy. That is, by augmenting the network, Western Australia provides a stronger investment signal to the renewable industry as well as other unconventional energy providers. While this stronger signal is unquantified, we believe the investment signal has an economic benefit that is relevant to the current evaluation.

9.1.2 Impact of forecast risk

This report has shown that the preferred network option can be delayed by a maximum of 2-3 years. Two of the three non-network alternatives to augmentation, demand side management and reactive power have already been largely exhausted. At best, these options are likely to offer only marginal additional assistance in ensuring acceptable levels of network reliability.

We have also considered the potential impact of climate change policies designed to constrain growth in carbon emissions. As discussed earlier, the NETS Scenario 1a potentially delays the attainment of expected 2010/11 energy demand levels on the SWIS by less than one year. Even the 'low' growth scenario has the potential to delay growth by just three years.

With respect to construction lead times, the expected delay of 2-3 years that would result from adoption of demand side management and reactive power offers little comfort. Consider the best possible scenario of one of the preferred network augmentation options being approved today. In the current economic environment, in which construction lead times are routinely extended, it is just as likely that the SWIS will require further demand side management and/or reactive power support to maintain network stability until the approved network augmentation is completed.

Table 7 **Difference between 2006 and 2007 IMOWA forecasts of maximum demand (MW)**

Year	10%PoE	50% PoE	90%PoE
2007/08	121	111	104
2008/09	125	113	107
2009/10	131	121	114
2010/11	133	123	114
2011/12	145	133	126
2012/13	150	138	129
2013/14	142	129	120
2014/15	140	127	118
2015/16	127	114	104

Data source: Independent Market Operator, *Statement of Opportunities Report,* July 2006, Appendix 3 pp. 41 and July 2007, Appendix 4 pp. v

Further, the 2006 and 2007 IMOWA's SOO reports should be compared. As shown in

Table 7, IMOWA upgraded its forecast of maximum demand with expected economic growth by more than 100MW. According to IMOWA the 2006 forecast under-estimated new air conditioner installations by approximately 65MW for the 2006/07 period.[20] This highlights the point that, in evaluating the need for augmentation, there is a risk that growth in the level of demand for electricity could be under-estimated. If growth turns out to be higher than expected, the SWIS is likely to sustain higher stress than is currently anticipated.

In summary, while the evaluation has considered factors that could reduce or delay the need for network augmentation, it is important to keep in mind that in the presence of forecast risk and construction lead time risk; an expected 2-3 years buffer can be easily lost.

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[20] Independent Market Operator, *2007 Statement of Opportunities Report*, July 2007, pp. 25

10 Conclusion

In evaluating Western Power Network's preferred network augmentation option of adding a 330kV electricity transmission line to its main South West transmission capacity, ACIL Tasman has used both quantitative and qualitative methods to analyse the options available. The main component of this analysis is based on the scenarios developed using ACIL Tasman's *PowerMark WA* model. This enables a rigorous and internally consistent way of assessing the size of the net benefits that are likely to be derived from upgrading the South West transmission line under a wide range of alternative market scenarios.

The underlying rationale driving the analysis is the difference in generation portfolios that arise from whether or not the proposed new South West to Perth transmission line is constructed. Due to the economics of different generation plant types and the lack of spare capacity on the existing South West to Perth transmission lines, the decision will influence the generation portfolio. The main difference is the share of the generation market that CCGTs account for in the portfolios. In this evaluation, we assumed that in the event that the South West augmentation did not proceed, new gas-fired electricity generators would be located within the Perth metropolitan area.

The model results show that if electricity demand continues to grow at an expected 2.2% and a carbon emission trading scheme is not introduced, the proposed South West augmentation is likely to maximise net benefit and therefore satisfies the Regulatory Test. However, given that a carbon emissions trading scheme is being proposed and there is currently increased public focus on adopting energy saving technology, it is prudent to test the assumptions underlying the model results.

The robustness of the results was assessed by varying the carbon emission price, gas price and load growth in various combinations. The key insight drawn from the results is that, despite increasing the cost to generators, the consumer always benefits from the South West augmentation due to increased competition within the SWIS. With regard to differences in total system cost, the results are inconclusive with the net present cost of the SWGEN option higher than METROGEN by no more 0.8%.

Given the results of the sensitivity analysis, we considered the non-network alternatives and qualitative factors relevant to the evaluation. With regard to the non-network alternatives, demand side management is unlikely to provide significant benefit. ACIL Tasman estimates that at most, a further 20MW of curtailable load is likely, which is clearly insufficient. Western Power advised that the benefit of further reactive power support is limited and unlikely to be cost effective. Further, Western Power advised that the SWIS is considered to be operating with little spare capacity.

With regard to increased electricity generation within the Perth metropolitan area, there are several generation sites available, such as Kwinana and Neerabup. However, Kwinana is constrained due to the expense of purchasing land and the high density of surrounding infrastructure. Neerabup appears to be a viable site for new generation, but will require network reinforcement. The suitability of the site will also need to be evaluated and will likely be the subject of investigation by regulatory authorities such as the Environmental Protection Authority.

Given the possibility of significant new electricity generation capacity locating in the Perth metropolitan area, it is necessary to consider the merits of delaying network augmentation. ACIL Tasman believes that capacity payments are sufficient to encourage construction of gas-fired 'peaking' plant. Offsetting this is the current very high price for domestic gas and the risks of delay in obtaining the necessary regulatory approvals. Hence, with the SWIS at or near capacity, it would be risky to deliberately delay network augmentation.

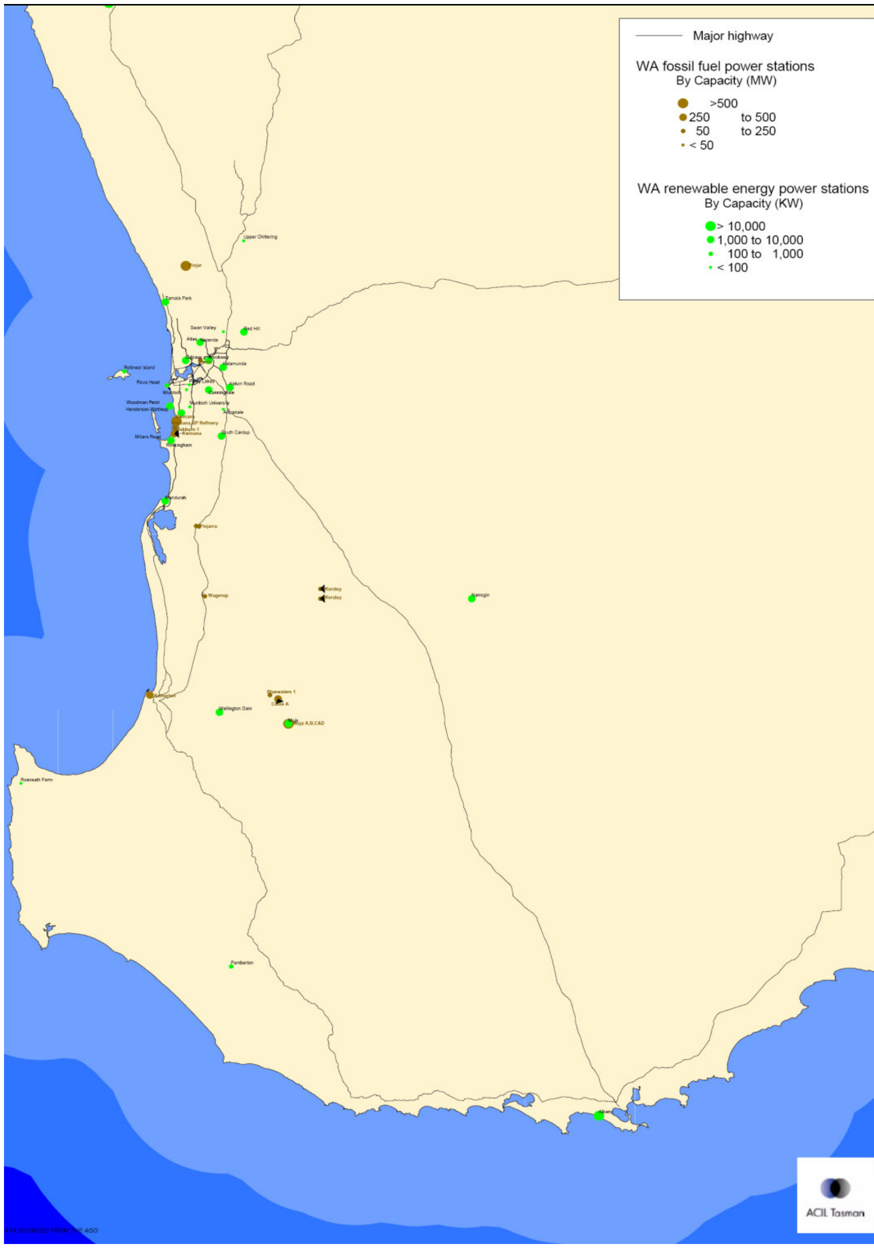
Another qualitative issue is the merits of facilitating an increased share of renewable and low carbon emission electricity generation. The tendency for alternative energy such as biomass and wind power to be located at some distance from major load centres places these generation alternatives at a disadvantage. To the extent that the South West augmentation provides a positive investment signal for the development of alternative energy, the South West augmentation has some, albeit unmeasured, benefit. Note that failure to upgrade the capacity of the South West transmission system will prevent additional load from the South West being transported to Perth. This is likely to adversely impact on the business cases of alternative electricity generators.

Finally, we considered forecast risk. We note the IMO's 2007 Statement of Opportunities Report increase of 167MW of reserve capacity and the jump in demand forecast, due largely to 200MW of air conditioner load installed in Western Australia. ACIL Tasman considers it likely that robust economic growth will continue to drive growth in electricity demand. Unless significant energy saving policies are implemented, it would appear, on the balance of probabilities, that there is a greater risk of under-estimating as opposed to over-estimating load growth in a system that is already near full capacity.

In considering the BAU case, ACIL Tasman recommends that Option 8 proceed as this is, on economic and technical grounds, the option that satisfies the Regulatory Test. With respect to the other market scenarios, the model results are unable to conclusively distinguish between the METROGEN and SWGEN generation options. In light of this, the options need to be evaluated on their technical merits. SKM confirm that, on technical grounds, Option 8 is the most suitable means of reinforcing the electricity supply to the metropolitan area of the SWIS. Based on this, ACIL Tasman recommends that Option 8 proceeds. In further support of this position, we point to the qualitative information as this is also relevant to the evaluation. Thus, in all circumstances, Option 8 is the option that maximises net benefit and therefore satisfies the Regulatory Test.

A Map of Existing Generation

Figure A1 **Existing generation sites**



Data source: ACIL Tasman generation database