Confidential

Net market benefits of Mid West transmission link

Assessment of the market benefits of the southern stage of the proposed Mid West transmission line to Eneabba

Prepared for Western Power

June 2010

ACIL Tasman
Economics Policy Strategy

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Contents

List of charts

List of tables

1 Introduction

ACIL Tasman has been engaged by Western Power Networks (WP) to undertake a series of electricity market projections to assist in estimating the market net benefits as required under the New Facilities Investment Test (NFIT) as it applies to the southern stage to Eneabba of the proposed Mid West transmission line (North Link). This study examines the impact on market participants namely generators and electricity consumers. For the purpose of the study the net benefit is defined as:

- the net present value (NPV) over the next 20 years of the difference in the net revenues of generators with and without North Link.
- NPV over the next 20 years of the difference in wholesale energy purchase costs with and without North Link.

The modelling of the Wholesale Electricity Market (WEM) was undertaken using ACIL Tasman's *WA PowerMark* model. This report provides the assumptions and results for a base case and six scenarios.

The base case and each of the scenarios presents the difference between two modelled situations:

- one which does not include development of North Link.
- the other which includes development of North Link

The difference between the two modelled situations is then used as the measure of the impact of the development on both generators and electricity customers.

The base case and scenarios are as follows:

Base Case: medium load growth incorporating greater new wind capacity in the case with North Link than without but with no new wind north of Eneabba. The Base Case uses $10.00/MWh load following costs for wind farms and capacity credit allowance of 40% of wind farm capacity.

Scenario 1: medium load growth with the same new plant assumptions in both the with and without North Link (i.e. no additional wind in the with North Link case)

Scenario 2: medium load growth but incorporating greater new wind capacity, including north of Eneabba, incorporated in the with North Link model run. This is the same as the Base Case with additional new wind capacity north of Eneabba included in the with North Link modelling.

Scenario 3: medium load growth with decreased revenue for wind farms. This is based on the same assumptions as the Base Case but a reduced capacity payment for wind farms - down to 20% of their capacity from the current 40%.

Scenario 4: medium load growth with increased load following costs ($15/MWh) and capacity credits reduced to 20% of wind farm capacity. This is based on the same assumptions as the Base Case except for an increased load following costs of $15.00/MWh and reduced capacity credits for wind farms.

Scenario 5: high load growth incorporating greater new wind capacity in the case with North Link than without but with no new wind north of Eneabba. Scenario 5 uses $10.00/MWh load following costs for wind farms and capacity credit allowance of 40% of wind farm capacity the same as the Base Case.

Scenario 6: high load growth with increased load following costs ($15/MWh) and capacity credits reduced to 20% of wind farm capacity. This is based on the same assumptions as the Base Case except for the higher load forecast and an increased load following costs of $15.00/MWh for wind farms and reduced capacity credits for wind farms.

It is forecast that additional Frequency Control Ancillary Services (FCAS) (most likely to be load following in the case of wind generation) costs will be incurred by wind generators with increasing wind penetration on the system to account for the need to operate additional thermal plant (typically gas fired OCGTs) to manage the impact of the intermittency of wind. This issue is currently under consideration by IMO's Renewable Energy Generation Working Group (REGWG). Based on the Rome Consulting report to REGWG we have assumed $10/MWh and $15/MWh wind generation as an estimate of the additional FCAS costs and assumed these are allocated to wind generators.

The final Section 6.1 of the report provides an estimate of the costs to provide isolated generation for a major mining load in North Country. This estimate has been provided to assess the likely net benefits to such a load of network connection by comparing the cost of isolated generation with the cost of wholesale market prices plus network connection and connection costs and ongoing charges.

1.1.1 Adaptation of the model into regions

For the purposes of this study ACIL Tasman's *WA PowerMark* model was adapted to undertake regional modelling of the WA market. This allowed measurement of the flows between regions in more accurate and timely analysis of new plant requirements in each region. The model was adapted to incorporate 3 regions - North, Central and South. This task involved:

- forecasting regional loads based on WP substation forecasts but adjusted to provide consistency with the Independent Market Operator's 2009 Statement of Opportunities (IMO 2009 SOO) load forecast. These annual peak and average load forecasts were used to manipulate the base regional load traces provided by WP for the year to 31 October 2009 to provide a forecast of the regional load traces.
- allocating generators to their respective regions
- defining two interconnectors – Central-North Interconnector and South-Central

2 Modelling assumptions

This section provides a description of the detailed assumptions and model settings for the current ACIL Tasman base case for the WEM.

The modelling assumptions covered in this section are considered under the headings:

- electricity forecast
- market supply
- details of plant
- new entrant costs
- other assumptions.

2.1 Electricity forecast

The forecast half hourly regional load traces are a key input to the market modelling. The base regional load traces for the year to 31 October 2009 supplied by WP have been projected forward to match the forecast peak and minimum demands and energy for each year. The model uses the generators sent-out as the measurement point in the system consistent with the approach adopted by IMO for the STEM.

The forecasts used by ACIL Tasman as a basis for calculation the regional load forecast were:

- annual system forecasts of peak demand and energy at 50% POE for medium and high growth from the IMO 2009 SOO on a sent-out basis
- high and central growth forecasts of substation peak and system coincident demands by Western Power on an as delivered from the main transmission system basis.

2.1.1 Regional forecasts

Background

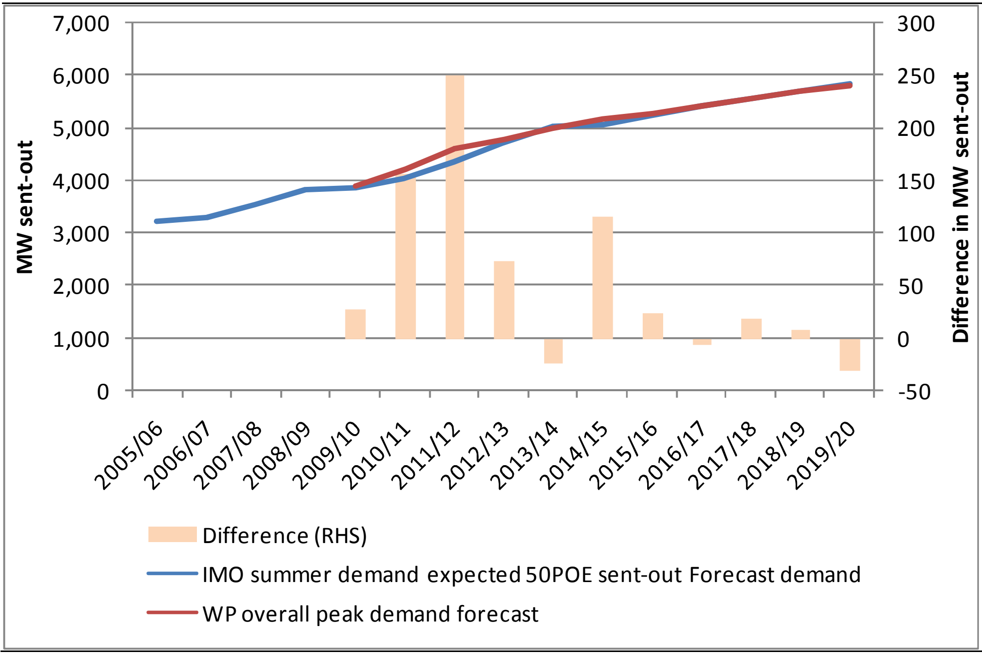
Forecasts for regional annual peak demand and energy have been aggregated into three regions being:

- North (north of Eneabba),
- Central (including Kalgoorlie)
- South

The annual substation peak demand forecast from Western Power[1] and the annual sent-out system peak demand and energy forecasts from the IMO 2009 SOO are the key inputs to the annual regional peak demand and energy forecast developed by ACIL Tasman for use in the market modelling. The IMO medium growth and the WP central forecasts compare favourably after adding an allowance for transmission losses to the Western Power forecast to put it on a comparable sent-out basis.

The comparison is shown in Chart 1. The largest difference occurs in 2011/12 and appears to be due to slightly different timing assumptions on major projects.

Chart 1 **Comparison between IMO and Western Power 50% POE medium growth forecasts (MW sent-out)**



Source: IMO 2009 SOO and unpublished forecast data supplied by Western Power

Regional peak demand

Base loads

The regional annual peak forecasts for the base loads (i.e. excluding major block loads) for ten years to 2028/29 have been taken from Western Power's substation forecast. These Western Power forecasts of the load as delivered

[1] ACIL Tasman has used the Western Power forecasts for the Mid West region dated February 2010. Western Power have subsequently updated its Mid West forecast (June 2010) with minor size and timing adjustments to its Central Case forecast and the inclusion of an addition 60MW load for the Oakajee Industrial Estate (in circa 2020). This update will not materially alter the findings in this report.

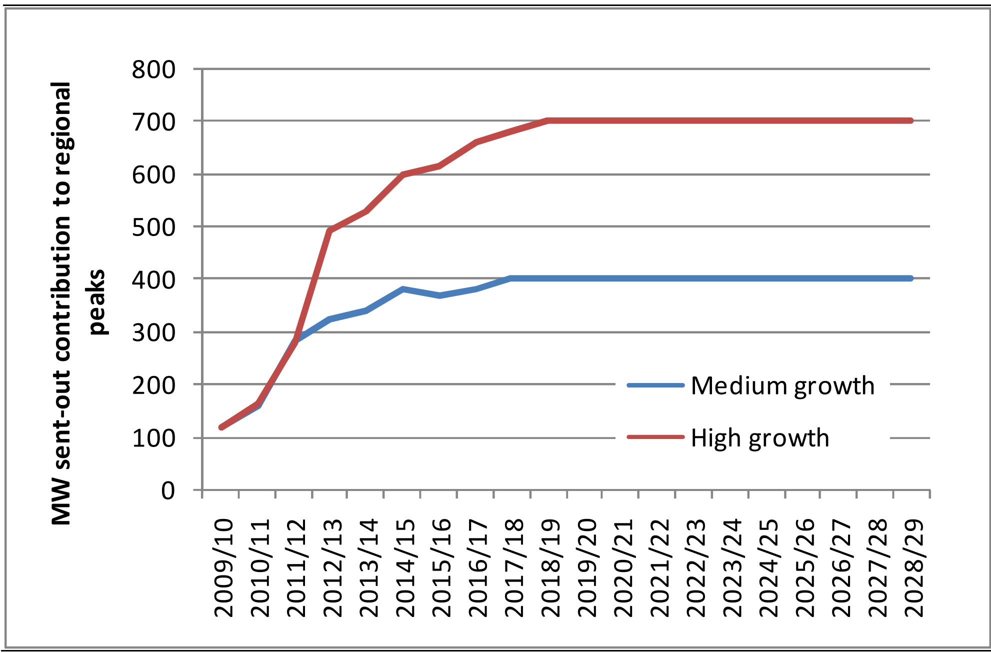
from the main transmission system were first adjusted to sent-out basis by adding an allowance for transmission losses and then adjusted further to align it with the 50% POE medium growth forecast for base loads in the IMO 2009 SOO for the first ten years. The base load forecast from the IMO 2009 SOO was calculated by subtracting an allowance for major block loads from the overall forecast.

This resulted in a central and high annual forecasts of regional base load demand at the time of the system peak which is consistent with the 50% POE medium and high annual peak demand forecasts published by the IMO in the 2009 SOO.

Major block loads

The size and timing of the major block loads as in the WP forecast have been adopted. These major block loads in the Western Power forecast were adjusted to a sent out basis by adding an allowance for transmission losses. The key difference in the block loads between the medium and high growth forecasts is in North region. The total block loads in the medium and high forecasts are shown in Chart 2.

Chart 2 **Major block loads - medium and high growth (MW)**



Total regional peak demand

A coincidence factor is applied to the regional base load contribution to system peak to produce a forecast of annual regional peak demands. The coincidence factors applied were:

- 0.94 for North
- 1.00 for Central region
- 0.97 for South region

The annual peaks for major block loads in the regions are added to the regional peak forecast for the base load to give the regional peak demand forecast at the time of system peak. It is assumed that the coincidence factor for the block loads is 1.00.

The same methodology has been employed for the medium and high growth outlooks at the 50% POE level.

The resultant regional peak demand forecast and associated growth rates are shown in Table 1 for the medium growth forecast and Table 2 for the high growth forecast.

Minimum load

Minimum load is an important input to the forecast load trace transformations. A forecast of regional minimum loads has been undertaken by ACIL Tasman for this purpose. For base loads this is the minimum load taken from the regional load traces project forward at the annual growth in energy. Minimum load for block loads assumed at 90% of peak is added to give the total minimum load on a regional basis. This can be assumed as these are 24 hour flat load type mining operations. Combined with the energy and peak demand forecast, the minimum load forecast ensures the right shape throughout the modelled period. This in turn helps in determining the efficient mix of peak and base load new entrant units.

2.1.2 Results for regional demand forecast

In order to obtain the individual demand forecast, the base year of half hourly loads is scaled for each year of the projection based on the forecast annual peak, average and minimum loads as detailed above. Technically, a non-linear transformation method is used to ensure all hourly data conform to both the annual energy and the summer peak loads.

The resultant sent-out annual peak, minimum and average demand for each region for the coming 20 years is summarised for the medium growth forecast in Table 1 and for the high growth forecast in Table 2.

The very strong growth in the north region in the 10 years to 2019/20 is due to the bock loads.

Table 1 **Annual demand forecast for medium growth scenarios (MW)**

	Sent-out summer peak demand			Sent-out minimum load			Annual average demand		
	North	Central	South	North	Central	South	North	Central	South
2009/10	129	3,117	728	49	851	361	73	1,473	471
2010/11	132	3,287	797	50	885	406	75	1,532	514
2011/12	240	3,453	853	139	901	430	153	1,559	541
2012/13	244	3,586	919	140	916	469	154	1,585	578
2013/14	267	3,713	937	157	940	474	170	1,627	586
2014/15	271	3,851	994	159	964	512	172	1,670	622
2015/16	275	3,950	989	159	979	501	173	1,695	613
2016/17	279	4,063	1,009	160	996	512	175	1,725	623
2017/18	283	4,184	1,054	161	1,014	537	176	1,757	648
2018/19	286	4,300	1,073	162	1,031	542	177	1,787	655
2019/20	290	4,376	1,093	163	1,038	547	178	1,799	662
2020/21	294	4,487	1,103	164	1,057	549	180	1,831	665
2021/22	297	4,599	1,119	165	1,076	553	181	1,865	672
2022/23	301	4,710	1,131	166	1,096	556	183	1,900	676
2023/24	305	4,819	1,148	167	1,115	561	184	1,934	683
2024/25	309	4,897	1,164	168	1,127	566	186	1,954	690
2025/26	312	4,974	1,181	169	1,140	571	187	1,977	697
2026/27	316	5,084	1,186	170	1,160	572	189	2,012	699
2027/28	320	5,194	1,194	171	1,180	574	190	2,047	701
2028/29	323	5,303	1,210	172	1,200	579	192	2,081	708
Forecast Growth									
2010/11 to 2019/20	8.5%	3.5%	4.1%	12.7%	2.0%	4.2%	9.3%	2.0%	3.5%
2019/20 to 2028/29	1.2%	2.2%	1.1%	0.6%	1.6%	0.6%	0.8%	1.6%	0.8%

Data source: ACIL Tasman with Western Power and IMO data

Table 2 **Annual demand forecast for high growth scenarios (MW)**

	Sent-out summer peak demand			Sent-out minimum load			Annual average demand		
	North	Central	South	North	Central	South	North	Central	South
2009/10	139	3,151	830	49	849	365	76	1,494	527
2010/11	145	3,270	897	53	875	411	80	1,541	570
2011/12	247	3,394	941	141	894	433	149	1,575	592
2012/13	427	3,522	1,006	299	899	469	272	1,585	622
2013/14	468	3,655	1,033	332	925	477	299	1,631	634
2014/15	504	3,793	1,100	362	954	519	323	1,682	675
2015/16	541	3,937	1,117	391	984	517	347	1,735	681
2016/17	577	4,085	1,159	421	1,019	538	372	1,799	707
2017/18	583	4,240	1,212	422	1,051	567	374	1,855	737
2018/19	607	4,400	1,245	441	1,085	577	390	1,915	753
2019/20	613	4,567	1,278	443	1,120	587	392	1,977	770
2020/21	619	4,712	1,309	444	1,149	596	395	2,030	785
2021/22	625	4,863	1,341	446	1,179	605	397	2,084	801
2022/23	630	5,018	1,373	448	1,211	615	400	2,139	816
2023/24	636	5,177	1,407	449	1,242	625	402	2,196	832
2024/25	642	5,343	1,441	451	1,275	634	405	2,254	849
2025/26	648	5,513	1,477	453	1,310	645	408	2,317	867
2026/27	655	5,689	1,514	454	1,346	656	410	2,381	885
2027/28	661	5,870	1,551	456	1,383	667	413	2,446	903
2028/29	667	6,057	1,590	458	1,421	679	416	2,514	922
Forecast Growth									
2010/11 to 2019/20	16.0%	3.8%	4.4%	24.6%	2.8%	4.9%	17.8%	2.8%	3.9%
2019/20 to 2028/29	0.9%	3.2%	2.5%	0.4%	2.7%	1.6%	0.6%	2.7%	2.0%

Data source: ACIL Tasman with Western Power and IMO data

Annual regional energy

The annual energy on a regional basis has been calculated by ACIL Tasman based on:

- regional peak demand
- reducing load factor
- annual energy forecast from the IMO

The regional energy forecast is shown in Table 3. The very high energy growth in the initial 10 years in the North region is due to the addition of major block loads.

Table 3 **Forecast annual energy for medium and high growth scenarios (MWh)**

	Medium				High			
	North	Central	South	STEM	North	Central	South	STEM
2009/10	642	12,901	4,123	17,666	667	13,089	4,619	18,376
2010/11	654	13,418	4,505	18,577	698	13,500	4,992	19,189
2011/12	1,340	13,655	4,737	19,732	1,308	13,796	5,188	20,292
2012/13	1,350	13,884	5,066	20,300	2,382	13,881	5,444	21,708
2013/14	1,490	14,254	5,135	20,878	2,621	14,287	5,557	22,465
2014/15	1,506	14,628	5,449	21,583	2,832	14,736	5,912	23,480
2015/16	1,517	14,848	5,370	21,735	3,043	15,198	5,964	24,205
2016/17	1,529	15,110	5,455	22,094	3,258	15,755	6,191	25,204
2017/18	1,540	15,394	5,679	22,613	3,278	16,250	6,456	25,985
2018/19	1,551	15,651	5,737	22,940	3,417	16,778	6,600	26,794
2019/20	1,562	15,761	5,800	23,123	3,438	17,323	6,747	27,508
2020/21	1,575	16,042	5,825	23,442	3,460	17,782	6,878	28,121
2021/22	1,588	16,335	5,884	23,807	3,482	18,255	7,013	28,749
2022/23	1,601	16,641	5,922	24,165	3,504	18,740	7,150	29,394
2023/24	1,615	16,938	5,984	24,536	3,526	19,237	7,292	30,055
2024/25	1,628	17,121	6,044	24,793	3,548	19,749	7,437	30,733
2025/26	1,642	17,316	6,108	25,066	3,571	20,294	7,591	31,456
2026/27	1,655	17,626	6,120	25,401	3,595	20,855	7,749	32,198
2027/28	1,669	17,932	6,143	25,744	3,618	21,431	7,911	32,960
2028/29	1,682	18,228	6,204	26,115	3,642	22,023	8,078	33,743
Forecast Growth								
2010/11 to 2019/20	9.3%	2.0%	3.5%	2.7%	17.8%	2.8%	3.9%	4.1%
2019/20 to 2028/29	0.8%	1.6%	0.8%	1.4%	0.6%	2.7%	2.0%	2.3%

Data source: ACIL Tasman with Western Power and IMO data

2.2 Load projection adopted for the modelling

2.2.1 Regional base load traces

The key characteristics of the regional base load traces for the year to 30 October 2009 are shown in Table 4.

Table 4 **Key characteristics of regional base load traces (year to Oct 2009)**

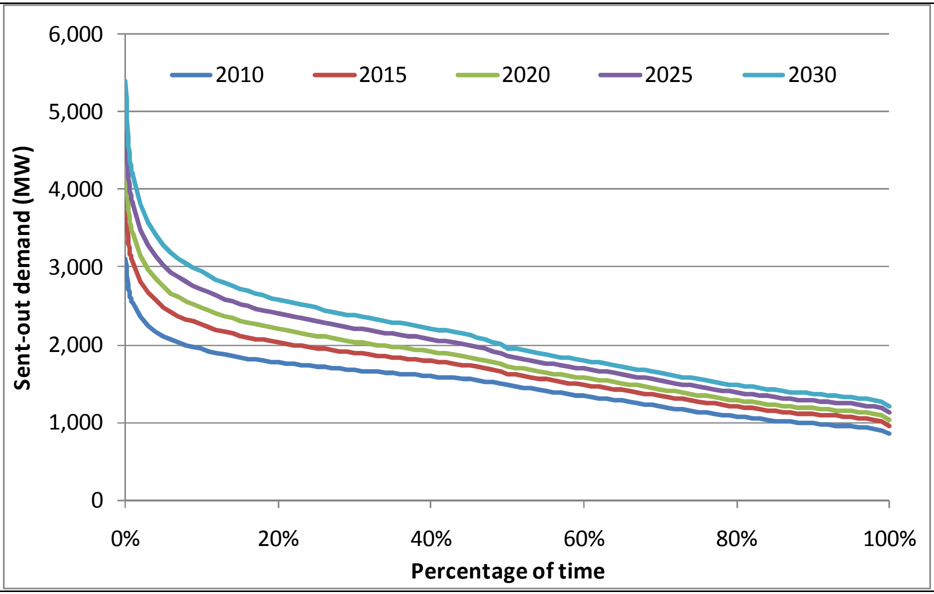
	North	Central	South	Total
Regional peak demand (MW)	133	2779	643	3511
Average regional demand (MW)	75	1350	419	1845
Load factor for year	56.3%	48.6%	65.2%	52.5%
Minimum regional load (MW)	47	792	263	1165
Time of system peak demand (date / time)	02-Feb-09 16:00:00			
Contribution to system peak	119.8	2768.1	623.0	3510.8
Coincidence between region and system peaks	0.90	1.00	0.97	1.00

Data source: Hourly load traces for year to 30 Oct 2009 supplied by Western Power

2.2.2 Load duration curves

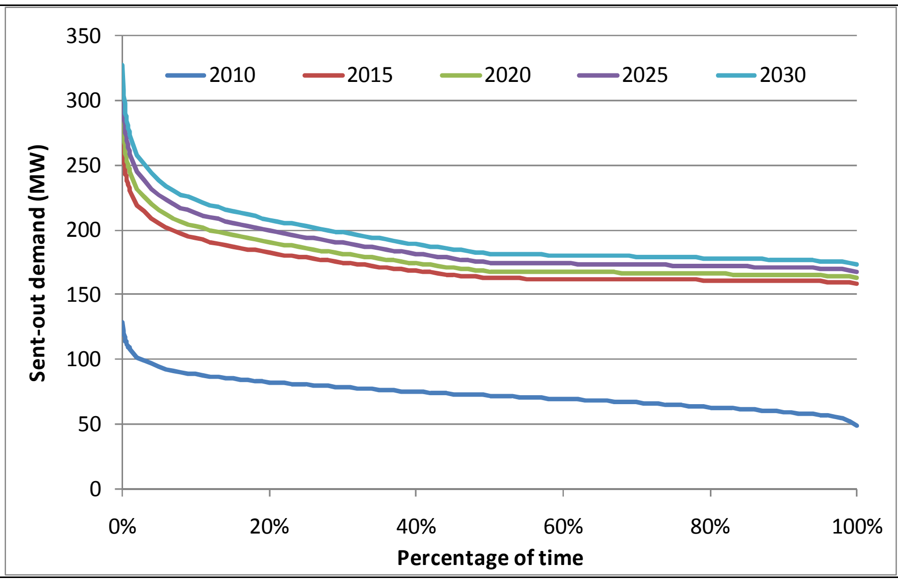
The resultant load duration curves (LDC) for selected years for the medium growth regional forecasts are shown in Chart 3 to Chart 5. The gap between the LDC for 2010 and 2015 in both North and South regions is due to the addition of major block loads in these regions.

Chart 3 **Projected Central region load duration curves - medium growth**



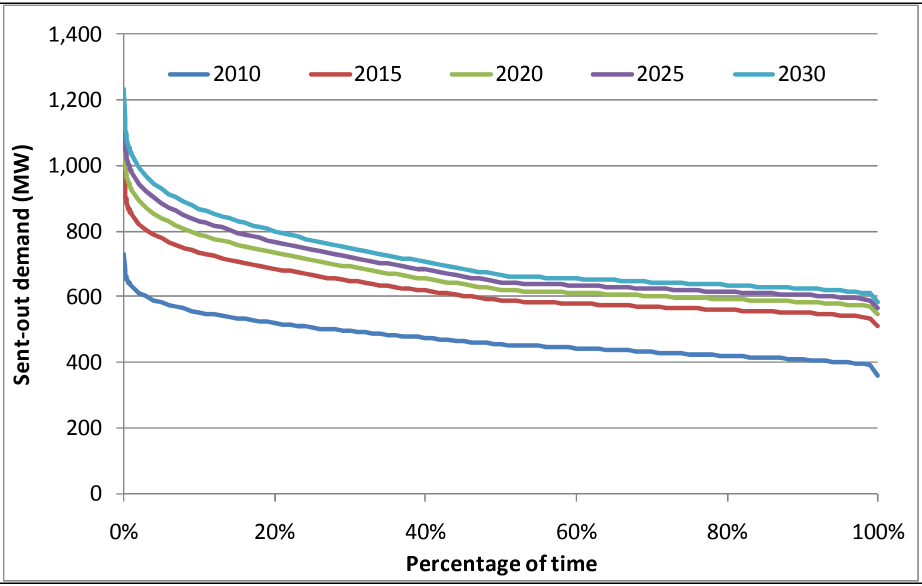
Source: ACIL Tasman

Chart 4 **Projected North region load duration curves – medium growth**



Source: ACIL Tasman

Chart 5 **Projected South region load duration curves – medium growth**

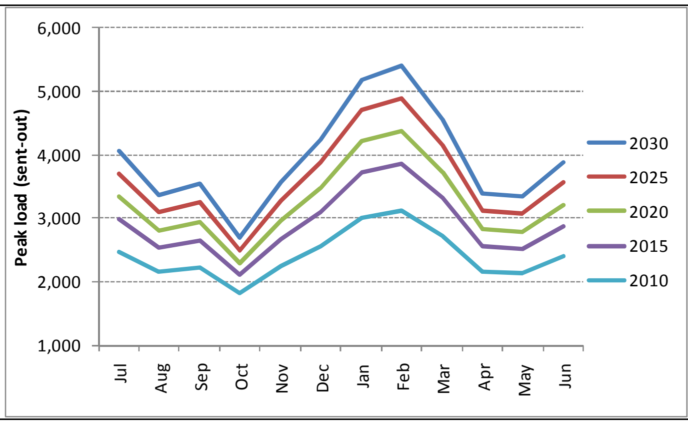


Source: ACIL Tasman

2.2.3 Monthly pattern of maximum demands

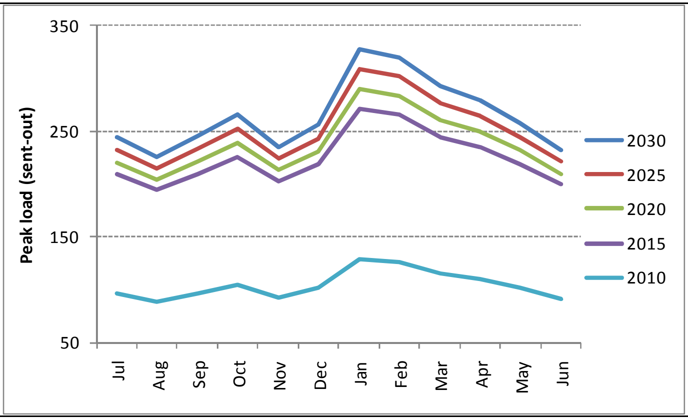
The monthly patterns of maximum demands for selected years for the medium growth regional forecasts are shown in Chart 6 to Chart 8. The gap between 2010 and 2015 in both North and South regions is due to the addition of major block loads in these regions.

Chart 6 **Projected Central region monthly peak demand – medium growth**



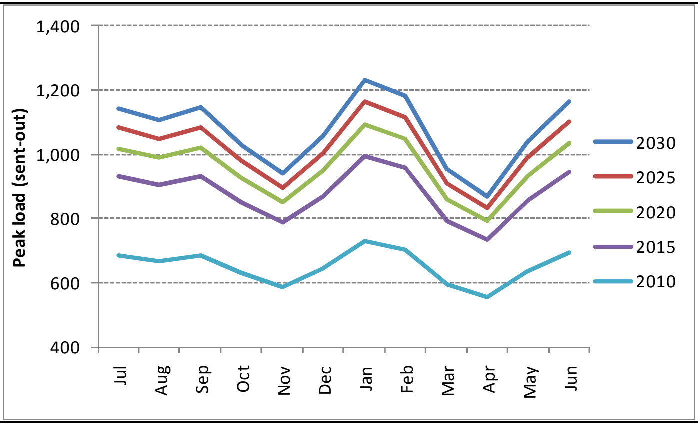
Source: ACIL Tasman

Chart 7 **Projected North region monthly peak demand – medium growth**



Source: ACIL Tasman

Chart 8 **Projected South region monthly peak demand – medium growth**

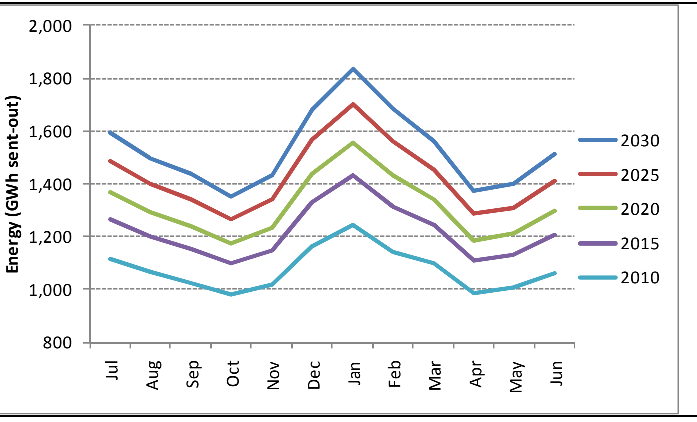


Source: ACIL Tasman

2.2.4 Monthly pattern of energy use

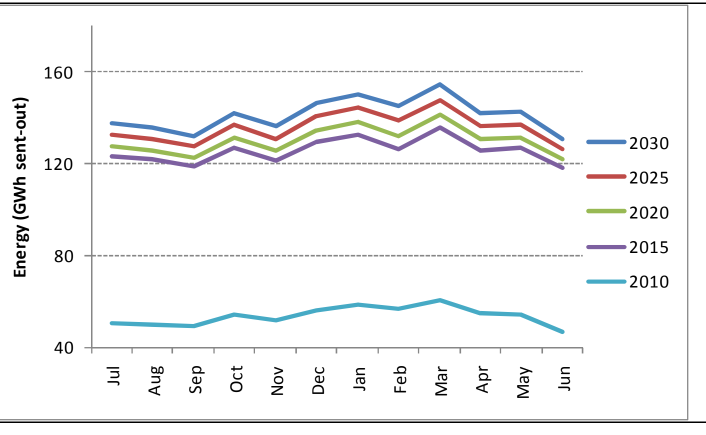
The monthly patterns of energy consumption for selected years for the medium growth regional forecasts are shown in Chart 9 to Chart 11. The gap between 2010 and 2015 in both North and South regions is due to the addition of major block loads in these regions.

Chart 9 Projected Central region monthly energy – medium growth



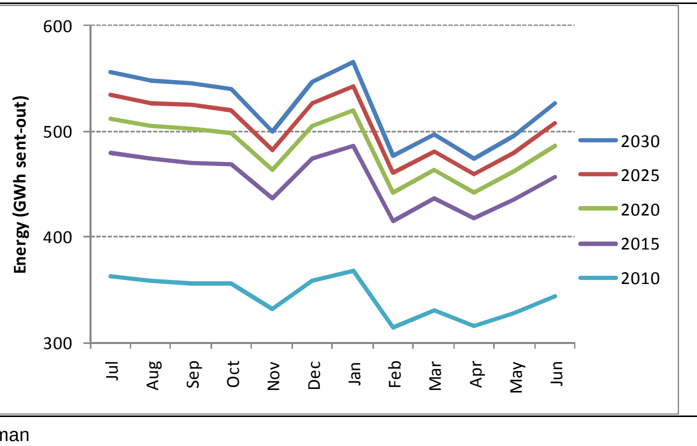
Source: ACIL Tasman

Chart 10 Projected North region monthly energy – medium growth



Source: ACIL Tasman

Chart 11 Projected South region monthly energy – medium growth



Source: ACIL Tasman

2.3 Market supply

Future capacity to supply electricity over the 20 year 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)
- capacity requirements as determined by the IMO under the market rules
- frequency and length of maintenance programmes as well as assumed forced outage rates.

When taken together with the electricity load forecast, the assumptions regarding plant additions and retirements will determine the supply-demand balance.

Table 5 outlines generator capacity in terms of generator type, and capacity, together with technical information assumed about each unit in the modelling. Table 6 lists the assumed withdrawals from the SWIS used in the modelling.

ACIL Tasman has taken into account information obtained from the market as well as published by the IMO in its 2009 SOO when constructing the assumptions regarding the timing of new plant and withdrawal of existing plant.

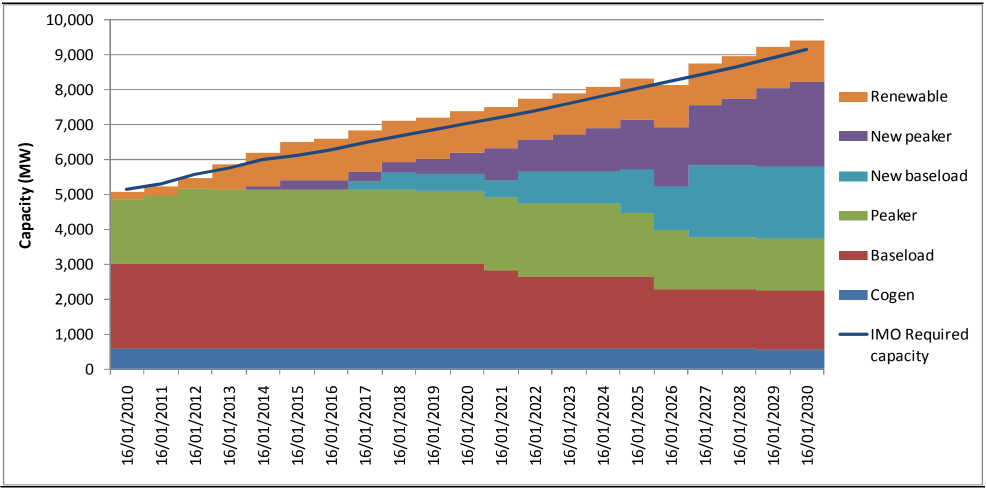
Table 5 **Detailed generator information**

Generator	Fuel type	STEM sent-out capacity (MW)	MinGen (% of capacity)	Var O&M ($/MWh) 2005-06	Thermal effieciency (sent-out HHV)	Auxiliary usage	Emissions Factor (t CO2/GJ)	Marginal loss factor (MLF)
Albany	Wind	21.6	0.0%	$1.00	100.0%	0.0%	0	1.0358
Alcoa Kwinana Cogen	Steam	5.0	0.0%	$0.00	30.0%	1.0%	0.0513	1.0174
Alcoa Wagerup Cogen	Steam	25.0	0.0%	$0.00	30.0%	1.0%	0.0513	1.0007
Bluewaters	Black coal	204.0	41.7%	$1.50	36.1%	7.4%	0.0931	0.9968
BP Cogen	Natural gas	116.0	77.6%	$0.00	33.0%	2.0%	0.02565	1.0165
Canning/Melville LFG	Landfill gas	9.0	0.0%	$3.50	30.0%	0.0%	0	1.0289
Cockburn	Natural gas	240.0	62.5%	$4.50	48.0%	2.4%	0.0513	1.0069
Collie	Black coal	315.0	50.8%	$1.50	36.0%	7.9%	0.0931	0.9968
Emu downs	Wind	80.0	0.0%	$1.00	100.0%	0.0%	0	1.0108
Geraldton	Distillate	20.8	0.0%	$9.00	29.0%	0.5%	0.0513	1.0618
Kalgoorlie	Distillate	38.2	0.0%	$9.00	33.0%	0.5%	0.0513	1.0798
Kalgoorlie Nickel	Natural gas	10.3	0.0%	$9.00	33.0%	0.5%	0.0513	1.2139
Kemerton	Natural gas	154.0	0.0%	$9.00	34.0%	0.5%	0.0513	1.0066
Kwinana A	Natural gas	111.5	0.0%	$8.00	32.0%	9.0%	0.0513	1.0069
Kwinana Alinta Cogen	Natural gas	160.0	60.0%	$0.00	32.0%	2.4%	0.0513	1.0174
Kwinana B	Natural gas	109.0	0.0%	$8.00	32.0%	9.0%	0.0513	1.0069
Kwinana C	Natural gas	185.0	16.2%	$7.00	33.0%	4.0%	0.0513	1.0069
Kwinana GT	Natural gas	20.8	0.0%	$9.00	32.0%	0.5%	0.0513	1.0069
Kwinana HEGT	Natural gas	100.0	0.0%	$9.00	39.0%	1.0%	0.0513	1.0069
Manjimup Biomass	Biomass	40.0	0.0%	$5.00	30.0%	2.0%	0	1.022
Muja C	Black coal	185.0	45.9%	$1.50	34.0%	8.5%	0.0931	1
Muja D	Black coal	211.0	47.4%	$1.50	35.0%	8.5%	0.0931	1
Mungarra	Natural gas	37.2	0.0%	$9.00	29.0%	0.5%	0.0513	1.0283
Neerabup Peaker	Natural gas	163.4	0.0%	$9.00	32.0%	1.0%	0.0513	1.0069
New Biomass	Biomass	40.0	0.0%	$5.00	30.0%	2.0%	0	1.022
New CCGT	Natural gas	250.0	0.0%	$4.50	50.0%	2.0%	0.0513	1.0069
New Entrant Cogen	Natural gas	160.0	60.0%	$0.00	32.0%	2.4%	0.0513	1.0286
New Peaking Plant	Natural gas	180.0	0.0%	$9.00	32.0%	1.0%	0.0513	1.0069
New Solar PV	Solar	8.0	0.0%	$1.50	100.0%	0.0%	0	1.0286
WIND_Collgar	Wind	206.0	0.0%	$11.00	100.0%	0.0%	0	1.1337
Newgen Power	Natural gas	240.0	0.0%	$3.00	32.0%	2.0%	0.0513	1.0069
Parkeston SCE	Natural gas	68.0	0.0%	$9.00	33.0%	0.5%	0.0513	1.2155
Pinjar A B	Natural gas	37.2	0.0%	$9.00	29.0%	0.5%	0.0513	1.0286
Pinjar C	Natural gas	116.0	0.0%	$9.00	29.0%	0.5%	0.0513	1.0286
Pinjar D	Natural gas	123.0	0.0%	$9.00	29.0%	0.5%	0.0513	1.0286
Pinjarra Alinta Cogen	Natural gas	136.6	60.0%	$0.00	34.1%	2.4%	0.02565	0.9931
Tiwest Cogen	Natural gas	22.0	68.2%	$0.00	32.0%	1.5%	0.02565	1.016
Wagerup Alinta Cogen	Natural gas	160.7	59.7%	$0.00	32.0%	2.4%	0.0513	1.0129
Wagerup Alinta Peaker	Distillate	160.7	0.0%	$9.00	34.1%	0.5%	0.0513	1.0129
Walkaway	Wind	89.1	0.0%	$1.00	100.0%	0.0%	0	0.9683
WIND_Badgingarra	Wind	130.0	0.0%	$11.00	100.0%	0.0%	0	1.0108
WIND_Grasmere	Wind	194.0	0.0%	$11.00	100.0%	0.0%	0	1.0358
WIND_Milyeannup	Wind	215.0	0.0%	$11.00	100.0%	0.0%	0	1.0358
WIND_Mumbida	Wind	90.0	0.0%	$11.00	100.0%	0.0%	0	1.0618
WIND_Nilgen	Wind	100.0	0.0%	$11.00	100.0%	0.0%	0	1.0108
WIND_Walkaway2	Wind	94.0	0.0%	$11.00	100.0%	0.0%	0	0.9683
Worsley	Black coal	-	0.0%	$0.00	28.0%	0.0%	0.0931	1.0066
Worsley SWCJV	Natural gas	123.0	58.0%	$0.00	33.0%	2.0%	0.02565	0.991

Source: ACIL Tasman

A summary of generation capacity by plant type in the WEM for the base case is provided in Chart 12. Retirement of existing base load capacity over the coming 20 years is replaced mainly CCGT capacity. The increase in renewable generation capacity is mainly provided by new wind farms.

Chart 12 **Generation capacity by plant type and IMO's required reserve capacity**



Source: ACIL Tasman

Table 6 **Assumed withdrawals from capacity in the Base Case and all scenarios**

DUID	Retired	Generation type	Portfolio	Fuel	Unit Size (MW)	Region
GERALDTON_GT1	31/12/2012	Gas turbine	Verve Energy	Distillate	20.8	Northern
WEST_KALGOORLIE_GT2	31/12/2018	Gas turbine	Verve Energy	Distillate	38.2	Central
WEST_KALGOORLIE_GT3	31/12/2024	Gas turbine	Verve Energy	Distillate	24.6	Central
KWINANA_G5	31/03/2020	Steam turbine	Verve Energy	Natural gas	185	Central
KWINANA_G6	31/03/2021	Steam turbine	Verve Energy	Natural gas	185	Central
KWINANA_GT1	31/03/2011	Gas turbine	Verve Energy	Natural gas	20.8	Central
MUJA_G5	31/12/2025	Steam turbine	Verve Energy	Black coal	185	Southern
MUJA_G6	31/12/2025	Steam turbine	Verve Energy	Black coal	185	Southern
MUJA_G7	31/03/2030	Steam turbine	Verve Energy	Black coal	211	Southern
MUJA_G8	31/03/2030	Steam turbine	Verve Energy	Black coal	211	Southern
MUNGARRA_GT1	31/03/2025	Gas turbine	Verve Energy	Natural gas	37.2	Northern
MUNGARRA_GT2	31/03/2025	Gas turbine	Verve Energy	Natural gas	37.2	Northern
MUNGARRA_GT3	31/03/2025	Gas turbine	Verve Energy	Natural gas	38.2	Northern
PINJAR_GT1	31/03/2024	Gas turbine	Verve Energy	Natural gas	37.2	Central
PINJAR_GT2	31/03/2024	Gas turbine	Verve Energy	Natural gas	37.2	Central
PINJAR_GT3	31/03/2024	Gas turbine	Verve Energy	Natural gas	38.2	Central
PINJAR_GT4	31/03/2024	Gas turbine	Verve Energy	Natural gas	38.2	Central
PINJAR_GT5	31/03/2024	Gas turbine	Verve Energy	Natural gas	38.2	Central
PINJAR_GT7	31/03/2024	Gas turbine	Verve Energy	Natural gas	38.2	Central
PINJAR_GT9	31/03/2026	Gas turbine	Verve Energy	Natural gas	116	Central
PINJAR_GT10	31/03/2026	Gas turbine	Verve Energy	Natural gas	116	Central
PINJAR_GT11	31/03/2030	Gas turbine	Verve Energy	Natural gas	123	Central
TIWEST_COG1	31/03/2028	Cogeneration	Verve Energy	Natural gas	22	Central

Source: ACIL Tasman

2.3.1 Demand – Supply balance

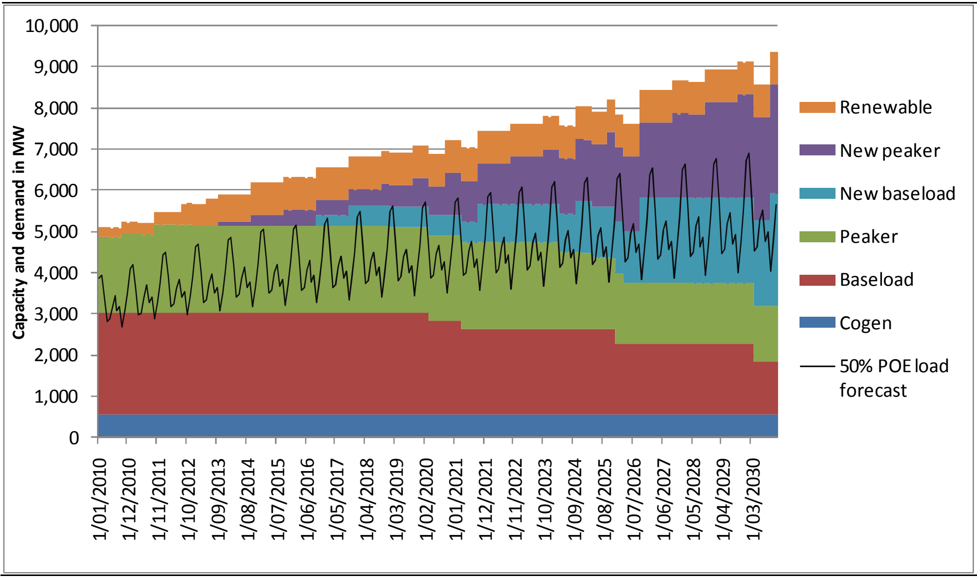
Chart 13 shows, on a monthly basis, the forecast total capacity by generator type and peak load in the SWIS.

The balance between plant and load is an important determinant of the STEM price. In the modelling the plant capacity will be set to meet the regulated requirement which is calculated as the sum of:

- forecast of medium summer peak demand at the 10% POE level
- an 8.2% reserve plant margin on 10% POE forecast
- 60 MW for balancing and ancillary services
- 19 MW backup for intermittent generation

This results in a regulated reserve margin, which declines, from around 23.3% at the commencement of the modelling period to around 19.1% by the end of the modelling period. While every attempt is made to ensure the reserve margin in the modelling matches the regulated reserve, the analysis suggests that in the initial eight years of the market, the regulated reserve will be exceeded because of the existing level of installed capacity and the committed projects over the next two to four years. Additionally, the regulated reserve will be exceeded as 'realistic' new entrant capacity rarely matches increases in the required reserve capacity.

Chart 13 **Capacity by generator type versus monthly peak demand**



Source: ACIL Tasman

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.

Table 7 **Plant outage rates and availability**

Station	Availability (% of time)	Forced outage rate (% of time)	Total planned outages (% of time)
Albany	100.00%	0.00%	0.00%
Alcoa Kwinana Cogen	90.99%	3.80%	5.21%
Alcoa Wagerup Cogen	90.99%	3.80%	5.21%
Pinjarra Alinta Cogen	86.99%	8.90%	4.11%
Wagerup Alinta Peaker	91.99%	3.90%	4.11%
Walkaway	100.00%	0.00%	0.00%
Bluewaters	92.07%	3.00%	4.93%
Canning/Melville LFG	95.00%	5.00%	0.00%
Cockburn	85.66%	4.20%	10.14%
Collie	88.31%	3.20%	8.49%
Emu downs	100.00%	0.00%	0.00%
Geraldton	85.06%	5.90%	9.04%
Kemerton	86.05%	6.00%	7.95%
Kwinana C	84.94%	5.20%	9.86%
Kwinana GT	84.94%	5.20%	9.86%
Kwinana HEGT	93.09%	3.90%	3.01%
Manjimup Biomass	91.92%	2.60%	5.48%
Muja C	77.94%	12.20%	9.86%
Muja D	85.24%	4.90%	9.86%
Mungarra	84.94%	5.20%	9.86%
New Biomass	97.40%	2.60%	0.00%
New CCGT	92.51%	4.20%	3.29%
New Entrant Cogen	91.99%	3.90%	4.11%
New Peaking Plant	93.09%	3.90%	3.01%
New Solar PV	100.00%	0.00%	0.00%
Newgen Power	92.51%	4.20%	3.29%
Neerabup Peaker	93.91%	3.90%	2.19%
Pinjar A B	84.94%	5.20%	9.86%
Pinjar C	84.94%	5.20%	9.86%
Pinjar D	84.94%	5.20%	9.86%
Pinjar A B	84.94%	5.20%	9.86%
Pinjar C	84.94%	5.20%	9.86%
BP Cogen	90.89%	5.00%	4.11%
Parkeston SCE	89.87%	5.20%	4.93%
Kalgoorlie Nickel	90.14%	5.20%	4.66%
Worsley SWCJV	90.89%	5.00%	4.11%
Tiwest Cogen	89.99%	5.90%	4.11%
Worsley	91.09%	4.80%	4.11%
Kalgoorlie	89.99%	5.90%	4.11%
WIND_Badgingarra	100.00%	0.00%	0.00%
WIND_Collgar	100.00%	0.00%	0.00%
WIND_Grasmere	100.00%	0.00%	0.00%
WIND_Milyeannup	100.00%	0.00%	0.00%
WIND_Mumbida	100.00%	0.00%	0.00%
WIND_Nilgen	100.00%	0.00%	0.00%
WIND_Walkaway2	100.00%	0.00%	0.00%

Source: ACIL Tasman

2.3.2 Carbon Pollution Reduction Scheme – assumptions

Australia is expected to introduce an emissions trading scheme, the so called Carbon Pollution Reduction Scheme (CPRS). Currently there is a high level of uncertainty about the timing and shape of the scheme.

A current announcement[2] by the government states:

> " ... the Government will not introduce the CPRS until after the end of the current commitment period of the Kyoto Protocol (which ends in 2012) and only when there is greater clarity on the actions of other major economies including the US, China and India."

Nevertheless, ACIL Tasman has assumed a 5% reduction in emissions by 2020 compared with 2000 for the purpose of this modelling in line with assumptions outlined in the Government's White Paper. Table 8 sets out the Government's White Paper estimates of emission permit prices associated with the 5% reduction target, but with a deferred start of the scheme to 2013. We note that these prices do not necessarily lead to a 5% physical reduction in emissions over 2000 levels by 2020 for the electricity sector or by extrapolation across the Australian economy as a whole. This is because the White Paper modelling assumes that some of the reduction is achieved through the purchase of permits from overseas exchanges thereby linking the domestic carbon price to the global carbon price. ACIL Tasman sees no significant impediment to purchasing permits from overseas. Notably a number of Australian companies with individual obligations to reduce emissions have operations overseas and would be expected to participate directly in overseas carbon markets.

Prices are projected through to 2030 maintaining similar escalation to 2020 reflecting deeper cuts beyond 2020.

[2] http://www.climatechange.gov.au/en/media/whats-new/cprs-delayed.aspx

Table 8 **Carbon price assumptions in 2008 real dollars**

Calendar Year	Carbon tax ($/tonne of CO2)
2010	$0.00
2011	$0.00
2012	$0.00
2013	$27.17
2014	$29.06
2015	$30.95
2016	$32.72
2017	$34.27
2018	$35.83
2019	$37.49
2020	$39.04
2021	$40.82
2022	$42.48
2023	$44.38
2024	$46.23
2025	$48.18
2026	$50.12
2027	$52.17
2028	$54.22
2029	$56.38
2030	$58.53
2031	$60.89
2032	$63.34
2033	$65.89
2034	$68.54
2035	$71.30

Note: Price inputs in PowerMark are set on a calendar year basis. The carbon permit price for a given calendar year is the average of the prices of the two surrounding financial years.

Data source: Federal Government CPRS White Paper and ACIL Tasman projection based on 2020 and interim targets

2.4 Short run marginal costs (SRMC)

Taken together, the fuel costs, thermal efficiency, impact of the CPRS, and variable O&M costs determine the short run marginal cost (SRMC) for each station. Table 9 summarises the nominal SRMC for each station assumed in the base case.

2.4.1 Variable O&M costs

The variable O&M costs of all plant are shown in Table 5 in the previous section. For all plant, it is assumed that the O&M costs escalate at 90% of CPI.

The variable O&M costs of wind farms has been increased from $1 of direct cost by $10 to reflect the possibility of future charges for load following services provided under a user pay principle currently under consideration by the IMO. The consequent increase in the SRMC has no bearing on the dispatch levels of wind farms having by far the lowest SRMCs compared to fossil fuel based generators.

2.4.2 Fuel costs

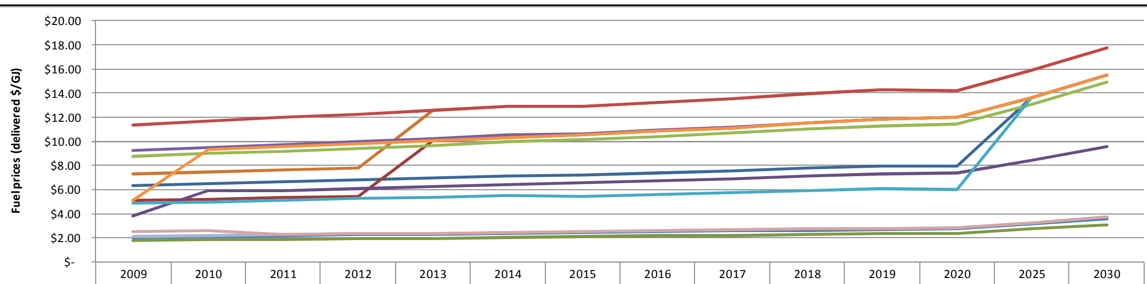
Fuel costs are more complex, in that they escalate at different rates and indeed, the escalation in some cases is not smooth – for example, reflecting step changes in the demand/supply balance of gas as well as changes (expiry and renewal) of coal contracts.

The projected price of fuel used in generation in the SWIS is shown in Chart 14. Coal is projected to remain the lowest cost fuel in the SWIS. The coal price is escalated using a rate of 2.7% pa.

At around $9.45/GJ in 2009-10, the delivered price of new gas contracts to Perth is substantially higher than existing contracts. Existing contract prices are assumed to converge to this higher level as contracts expire.

The NewGen gas price is understood to be at a fixed rate (with CPI escalation provisions but no price re-openers) until 2023–24 at which point its price is assumed to become the market rate for Perth deliveries.

Chart 14 **Fuel cost projections**



	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2025	2030
Alcoa gas price	$6.32	$6.46	$6.63	$6.80	$6.98	$7.16	$7.18	$7.37	$7.57	$7.77	$7.97	$7.96	$13.61	$15.45
Alinta - existing contracts	$5.09	$5.19	$5.32	$5.45	$10.03	$10.29	$10.56	$10.83	$11.10	$11.53	$11.85	$11.95	$13.61	$15.45
Aviva coal	$1.78	$1.82	$1.87	$1.92	$1.98	$2.03	$2.08	$2.14	$2.20	$2.26	$2.32	$2.38	$2.72	$3.11
Coal and gas into Kwinana (50% coal)	$3.81	$5.95	$5.89	$6.05	$6.20	$6.36	$6.53	$6.70	$6.87	$7.12	$7.32	$7.41	$8.44	$9.59
Goldfields existing	$7.32	$7.43	$7.60	$7.77	$12.58	$12.90	$12.89	$13.22	$13.56	$13.90	$14.26	$14.17	$15.90	$17.72
Griffin coal	$2.06	$2.11	$2.17	$2.23	$2.29	$2.35	$2.41	$2.48	$2.55	$2.61	$2.68	$2.76	$3.15	$3.60
New Gas Goldfields	$11.37	$11.66	$11.96	$12.27	$12.58	$12.90	$12.89	$13.22	$13.56	$13.90	$14.26	$14.17	$15.90	$17.72
New Gas North of Perth	$8.73	$8.95	$9.18	$9.42	$9.68	$9.95	$10.11	$10.39	$10.69	$10.99	$11.29	$11.45	$13.09	$14.93
New Gas Perth	$9.22	$9.46	$9.70	$9.95	$10.22	$10.50	$10.63	$10.92	$11.22	$11.53	$11.85	$11.95	$13.61	$15.45
NewGen gas price	$4.88	$4.98	$5.10	$5.22	$5.35	$5.49	$5.46	$5.60	$5.74	$5.88	$6.03	$5.97	$13.61	$15.45
Verve - existing contract	$5.09	$9.30	$9.54	$9.78	$10.03	$10.29	$10.56	$10.83	$11.10	$11.53	$11.85	$11.95	$13.61	$15.45
Wesfarmers coal - new	$2.13	$2.19	$2.25	$2.31	$2.37	$2.44	$2.50	$2.57	$2.64	$2.71	$2.78	$2.86	$3.27	$3.73
Wesfarmers/Griffin coal	$2.53	$2.59	$2.25	$2.31	$2.37	$2.44	$2.50	$2.57	$2.64	$2.71	$2.78	$2.86	$3.27	$3.73

Source: ACIL Tasman

2.4.3 Thermal efficiency

Table 5 above includes the assumed thermal efficiency for each generator in the modelling. It is worth noting that the thermal efficiency values tabulated are measured as sent-out high heat values (HHV).

2.4.4 Marginal loss factors

The marginal loss factors (MLFs) assumed in the modelling are shown in Table 5 in the previous section. The MLFs are used in the settlement routine to adjust the offers of the generators. The generators themselves do not make this alteration to their offer curves – hence the short run marginal costs tabulated in the flowing section have not been adjusted for MLFs.

2.4.5 Short run marginal costs

Taking together the fuel costs, thermal efficiency, emission costs, variable O&M costs. Fuel costs for cogen units have been adjusted to account for the steam production component. Table 9 summarises the nominal SRMC for selected generation units assumed in the modelling.

Table 9 **Calculated SRMC for selected stations**

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2025	2030
Alcoa Kwinana Cogen	$ 28.60	$ 29.23	$ 29.98	$ 30.76	$ 53.07	$ 55.96	$ 58.24	$ 61.25	$ 64.18	$ 67.22	$ 70.47	$ 72.75	$ 112.86	$ 140.37
Alcoa Pinjarra Cogen	$ 28.60	$ 29.23	$ 29.98	$ 30.76	$ 53.07	$ 55.96	$ 58.24	$ 61.25	$ 64.18	$ 67.22	$ 70.47	$ 72.75	$ 112.86	$ 140.37
Alcoa Wagerup Cogen	$ 28.60	$ 29.23	$ 29.98	$ 30.76	$ 53.07	$ 55.96	$ 58.24	$ 61.25	$ 64.18	$ 67.22	$ 70.47	$ 72.75	$ 112.86	$ 140.37
Bluewaters	$ 22.05	$ 22.64	$ 23.25	$ 23.87	$ 53.76	$ 57.23	$ 60.85	$ 64.47	$ 67.97	$ 71.62	$ 75.54	$ 79.46	$ 103.43	$ 134.33
BP Cogen	$ 20.92	$ 21.34	$ 21.86	$ 22.41	$ 43.45	$ 45.37	$ 46.70	$ 48.69	$ 50.66	$ 63.75	$ 66.24	$ 67.87	$ 82.09	$ 99.41
Cockburn	$ 42.75	$ 74.48	$ 76.39	$ 78.34	$ 93.79	$ 97.14	$ 100.60	$ 104.11	$ 107.61	$ 112.28	$ 116.26	$ 118.67	$ 140.98	$ 167.65
Collie	$ 26.80	$ 27.52	$ 24.12	$ 24.76	$ 54.75	$ 58.26	$ 61.91	$ 65.57	$ 69.10	$ 72.79	$ 76.74	$ 80.70	$ 104.89	$ 136.03
Geraldton	$ 314.73	$ 317.94	$ 321.28	$ 324.62	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Kalgoorlie	$ 277.70	$ 280.55	$ 283.51	$ 286.48	$ 309.01	$ 313.98	$ 319.04	$ 324.10	$ 329.08	$ 334.25	$ -	$ -	$ -	$ -
Kalgoorlie Nickel	$ 89.08	$ 90.54	$ 92.59	$ 94.67	$ 166.98	$ 172.60	$ 174.71	$ 180.52	$ 186.38	$ 192.37	$ 198.68	$ 200.02	$ 233.72	$ 272.92
Kemerton	$ 63.07	$ 107.93	$ 110.69	$ 113.52	$ 135.40	$ 140.21	$ 145.17	$ 150.20	$ 155.23	$ 161.90	$ 167.61	$ 171.09	$ 203.06	$ 241.24
Kwinana A	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Kwinana Alinta Cogen	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Kwinana B	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Kwinana C	$ 48.69	$ 72.23	$ 71.84	$ 73.69	$ 95.15	$ 98.98	$ 102.95	$ 106.96	$ 110.93	$ 115.80	$ 120.27	$ -	$ -	$ -
Kwinana GT	$ 286.09	$ 289.02	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Kwinana GT 2	$ -	$ -	$ -	$ 101.78	$ 121.08	$ 125.51	$ 128.60	$ 133.22	$ 137.85	$ 142.62	$ 147.63	$ 150.71	$ 178.78	$ 212.30
Kwinana GT 3	$ -	$ -	$ 104.08	$ 106.74	$ 127.08	$ 131.72	$ 134.98	$ 139.83	$ 144.70	$ 149.71	$ 154.97	$ 158.20	$ 187.70	$ 222.94
Manjimup Biomass	$ -	$ 11.61	$ 11.98	$ 12.24	$ 12.50	$ 12.76	$ 13.14	$ 13.41	$ 13.68	$ 14.08	$ 14.36	$ 14.76	$ 16.61	$ 18.57
Muja C	$ 28.28	$ 29.04	$ 25.44	$ 26.12	$ 57.88	$ 61.59	$ 65.45	$ 69.32	$ 73.06	$ 76.96	$ 81.14	$ 85.33	$ 110.92	$ -
Muja D	$ 27.52	$ 28.26	$ 24.76	$ 25.42	$ 56.27	$ 59.88	$ 63.63	$ 67.39	$ 71.02	$ 74.81	$ 78.88	$ 82.95	$ 107.82	$ -
Mungarra	$ 72.35	$ 124.91	$ 128.10	$ 131.38	$ 156.99	$ 162.58	$ 168.36	$ 174.21	$ 180.05	$ 187.83	$ 194.47	$ 198.50	$ -	$ -
Neerabup Peaker	$ -	$ 115.87	$ 118.83	$ 121.87	$ 145.34	$ 150.68	$ 154.40	$ 159.96	$ 165.55	$ 171.30	$ 177.34	$ 181.03	$ 214.89	$ 255.35
New Biomass	$ -	$ -	$ 11.98	$ 12.24	$ 12.50	$ 12.76	$ 13.14	$ 13.41	$ 13.68	$ 14.08	$ 14.36	$ 14.76	$ 16.61	$ 18.57
New CCGT Central	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 108.02	$ 111.85	$ 114.16	$ 135.61	$ 161.25
New CCGT_NorthA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 100.53	$ 104.11	$ 107.87	$ 110.52	$ 131.85	$ 157.51
New Peaking Plant Central	$ -	$ -	$ -	$ -	$ -	$ -	$ 154.40	$ 159.96	$ 165.55	$ 171.30	$ 177.34	$ 181.03	$ 214.89	$ 255.35
New Peaking Plant North	$ -	$ -	$ -	$ -	$ -	$ 150.68	$ 154.40	$ 159.96	$ 165.55	$ 171.30	$ 177.34	$ 181.03	$ 214.89	$ 255.35
New Solar PV	$ -	$ -	$ 1.62	$ 1.66	$ 1.70	$ 1.74	$ 1.78	$ 1.83	$ 1.87	$ 1.92	$ 1.97	$ 2.02	$ 2.28	$ 2.58
Newgen Power	$ 41.21	$ 42.04	$ 43.08	$ 44.14	$ 58.68	$ 61.10	$ 62.41	$ 64.91	$ 67.39	$ 69.95	$ 72.66	$ 73.76	$ 140.98	$ 167.65
Parkeston SCE	$ 89.08	$ 90.54	$ 92.59	$ 94.67	$ 166.98	$ 172.60	$ 174.71	$ 180.52	$ 186.38	$ 192.37	$ 198.68	$ 200.02	$ 233.72	$ 272.92
Pinjar A B	$ 72.35	$ 124.91	$ 128.10	$ 131.38	$ 156.99	$ 162.58	$ 168.36	$ 174.21	$ 180.05	$ 187.83	$ 194.47	$ 198.50	$ -	$ -
Pinjar C	$ 72.35	$ 124.91	$ 128.10	$ 131.38	$ 156.99	$ 162.58	$ 168.36	$ 174.21	$ 180.05	$ 187.83	$ 194.47	$ 198.50	$ 235.70	$ -
Pinjar D	$ 72.35	$ 124.91	$ 128.10	$ 131.38	$ 156.99	$ 162.58	$ 168.36	$ 174.21	$ 180.05	$ 187.83	$ 194.47	$ 198.50	$ 235.70	$ -
Pinjarra Alinta Cogen	$ 20.24	$ 20.65	$ 21.16	$ 21.68	$ 42.05	$ 43.91	$ 45.19	$ 47.12	$ 49.03	$ 61.69	$ 64.10	$ 65.68	$ 79.44	$ 96.21
Tiwest Cogen	$ 21.57	$ 22.00	$ 22.55	$ 23.11	$ 44.81	$ 46.79	$ 48.16	$ 50.21	$ 52.25	$ 65.74	$ 68.31	$ 69.99	$ 84.65	$ -
Wagerup Alinta Peaker	$ 269.04	$ 271.80	$ 274.68	$ 277.56	$ 299.37	$ 304.19	$ 309.10	$ 314.00	$ 318.82	$ 323.84	$ 329.03	$ 334.21	$ 363.39	$ 397.60
WIND	$ 11.28	$ 11.56	$ 11.85	$ 12.14	$ 12.45	$ 12.76	$ 13.08	$ 13.40	$ 13.74	$ 14.08	$ 14.43	$ 14.79	$ 16.74	$ 18.94
Worsley	$ 27.39	$ 28.15	$ 28.93	$ 29.71	$ 68.22	$ 72.67	$ 77.31	$ 81.95	$ 86.44	$ 91.12	$ 96.14	$ 101.17	$ 131.92	$ 171.58
Worsley SWCJV	$ 20.92	$ 21.34	$ 21.86	$ 22.41	$ 43.45	$ 45.37	$ 46.70	$ 48.69	$ 50.66	$ 63.75	$ 66.24	$ 67.87	$ 82.09	$ 99.41

Source: ACIL Tasman

2.5 Generator offer curves

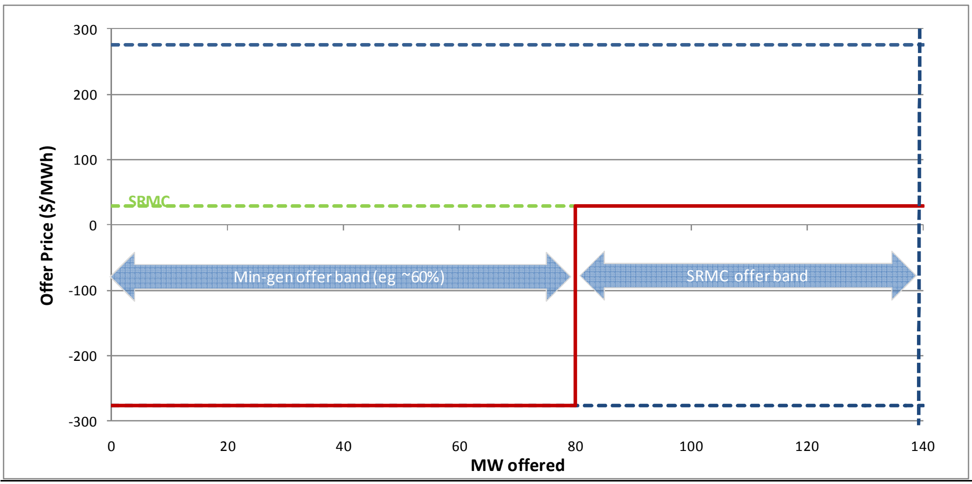
Generator offer curves are constructed with an initial price cap of $276/MWh for gas and coal fired fuel plant and $473.00/MWh for liquid fuel plant. The structural differences in market design in the SWIS result in generator offer curves which match more closely marginal costs.

The unit offer curve is comprised of two segments:

- Minimum generation level: typically associated with coal plant, reflecting the lowest level of stable generation before unit decommitment. For coal plant this is normally in the range 40-50% of sent-out capacity. This quantity is offered at a price level which approximates the STEM floor price (currently –$276/MWh). Cogen plants also typically carry a minimum generation level in the modeling to reflect the need to meet steam supply obligations.
- SRMC band: the residual cumulative capacity up the total capacity of the unit. The volume in this band is priced at the units SRMC.

These bands are shown graphically in Chart 15.

Chart 15 **Offer curve construction**



2.6 Capacity payments

2.6.1 Capacity auction

The modelling does not incorporate an explicit capacity auction. The plant program in the modelling is determined through commercial entry considerations. Should generation investment using this approach fall short of the regulated requirement, OCGT plant (having the lowest fixed costs of the various generation technologies) are introduced until the regulated level is met.

The program also ensures that the mix of peaking and base/intermediate load plant is maintained is determined by reference to the load duration curve.

2.6.2 Projected capacity price

The capacity price is taken to be the fixed cost of a low priced OCGT. The fixed cost includes fixed O&M costs plus an allowance for capital. This approach has been adopted because retailers, in negotiating for capacity credits, have the option of constructing such a plant to provide their own capacity credits.

Table 10 **Projected capacity price based on fixed costs for an OCGT**

Financial Year	Reserve Capacity Price ($/MW/year)	Max Reserve Capacity Price ($/MW/year)
2009-10	108,459	142,200
2010-11	144,235	173,400
2011-12	133,775	164,100
2012-13	198,453	238,500
2013-14	194,398	231,191
2014-15	188,976	223,881
2015-16	183,150	216,572
2016-17	174,647	209,262
2017-18	167,528	201,953
2018-19	162,014	194,643
2019-20	157,350	187,334
2020-21	152,294	180,025
2021-22	154,779	184,117
2022-23	159,052	188,302
2023-24	163,092	192,582
2024-25	165,784	196,960
2025-26	170,483	201,438
2026-27	173,899	206,017
2027-28	178,114	210,701
2028-29	181,455	215,491
2029-30	186,727	220,390
2030-31	190,872	225,400

Data source: ACIL Tasman

2.7 Incorporation of REC scheme and wind generation in the SWIS

A key assumption in modelling the North Link interconnector upgrade is the development of new wind generation capacity in the SWIS. ACIL Tasman modelling suggests that the current wind capacity of around 190 MW will increase by 835 MW by 2016. The following new WA wind farms included in the modelling have been shown as being viable in an Australia wide market for renewable energy:

- Collgar wind farm (206 MW) – Central region;
- Badgingarra wind farm (130 MW) – Central region;
- Milyeannup wind farm (215 MW) – South region;
- Mumbida wind farm (90 MW) – North region;
- Nilgen wind farm (100 MW) – Central region; and
- Walkaway 2 wind farm (94 MW) – North region.

In order to isolate the effects of the interconnector upgrade, ACIL Tasman has excluded all new wind farms north of Eneabba from the base case scenario, as these required a northerly extension of the proposed North Link which is not being assessed in this report. However, Scenario 2 provides an assessment the total net benefit with all wind generation if there was a complete north to south interconnector upgrade.

The viability and timing of these wind farms has been determined using ACIL Tasman's in-house REC model called *RECMark*. ACIL Tasman utilises *RECMark* to examine the outlook for renewable generation developments in response to the recently announced enhanced Renewable Energy Target (RET). The main underlying assumptions in *RECMark* determining the dispatch of new renewable projects include:

- currently committed and proposed renewable projects (including efficiency, capital costs or operating costs)
- future possible renewable projects
- black energy price and other income for all electricity generating regions
- REC shortfall penalty
- limited banking/borrowing of RECs.

Based on these assumptions the model determines the profitability of renewable projects over their lifetime and consequently schedules the entry of renewable energy across Australia. Due to the relatively high capacity factors and higher black energy price compared to those in the east, wind farms in the SWIS have a competitive advantage over wind farms in eastern Australia, despite their higher capital and operating costs. This would still hold true in the even without the capacity payments received by wind farms in the SWIS.

This can be seen in Table 11, which shows a comparison between the NEM and SWIS, as well as the projected REC prices. The black energy prices in the SWIS are consistently higher, compared with New South Whales, Queensland and Victoria. This would indicate that wind farms in the SWIS will be more profitable based on the STEM price alone without receiving any capacity payments.

Table 11 **Black energy price SWIS and NEM, and REC price (nominal $/MWh; $/REC respectively)**

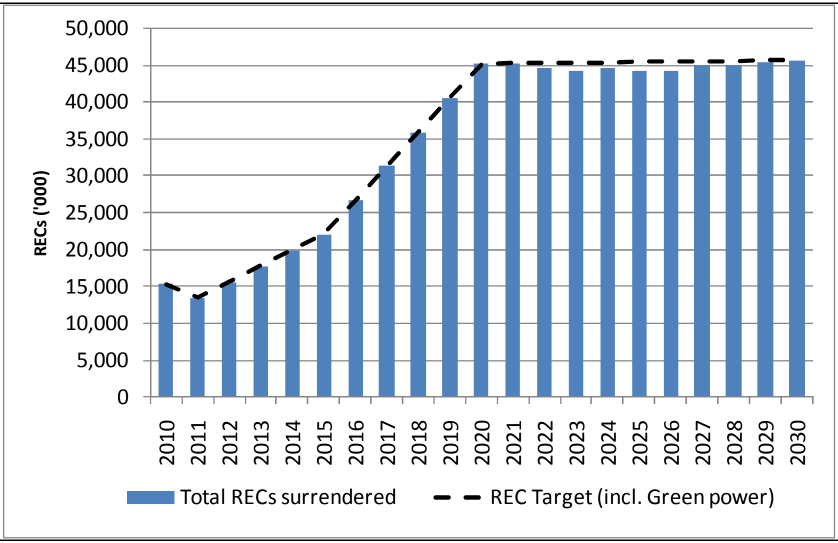
Financial year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2025	2030
STEM price	$44.33	$53.96	$71.60	$74.85	$78.10	$84.40	$86.42	$87.17	$90.27	$94.84	$100.02	$131.78	$165.89
NEM - NSW	$43.20	$34.30	$47.30	$74.70	$80.30	$80.60	$89.60	$86.70	$97.40	$96.20	$100.00	$114.90	$146.20
NEM - QLD	$31.10	$26.20	$45.30	$71.70	$77.20	$75.10	$80.60	$80.80	$81.50	$87.20	$88.40	$106.50	$128.30
NEM - SA	$54.80	$56.70	$67.10	$85.30	$76.40	$90.80	$88.50	$95.20	$100.20	$98.70	$99.80	$122.80	$152.00
NEM - VIC	$32.80	$38.60	$53.10	$77.20	$75.50	$81.20	$81.80	$84.60	$93.50	$90.40	$92.40	$111.60	$134.40
REC price	$36.50	$39.00	$41.70	$44.50	$47.50	$50.70	$54.20	$57.90	$61.80	$66.00	$70.50	$92.90	$92.90

Data source: ACIL Tasman modelling

Chart 16 shows the RECs surrendered each year against the REC target under the Base Case scenario. The target is fully met over the period, with slight shortfalls during 2022-2029 being made up in subsequent years[3].

[3] Under the legislation, a liable party who pays a shortfall penalty has three years to surrender RECs for this shortfall and have the penalty refunded.

Chart 16 **REC supply-demand balance: Base Case**



Data source: ACIL Tasman modelling

Furthermore, ACIL Tasman looked at the sensitivity of Western Australian wind farms to increases in their SRMC expenditure due to a cost of between \$10.00/MWh and \$15.00/MWh for load following services being levied on them. ACIL Tasman found that the same number of wind farms would proceed based on the relatively higher capacity factors as compared with proposed projects on the east coast of Australia. Nevertheless, the increase would still result in an increase in the expected REC price. Table 12 shows the different REC price outcomes under a \$10.00/MWh and \$15.00/MWh load following service charge levied on wind farms. The REC price reaches the penalty price by 2025, signalling that the price is only just sufficient to enable sufficient new generation to be deployed. This is due to the fact that there is not enough REC revenue left in the scheme for wind farms to collect, as the current scheme is designed to expire after 2030. In fact, ACIL Tasman modelling shows that no significant wind farms will be commissioned after 2018.

Table 12 shows the REC price outcomes under this scenario. The REC price is reasonably low in the early years, but still reaches the penalty level in the last 5-6 years of the scheme, indicating that this price level is required in order to meet the target. The REC price is sensitive to the black energy price, the cost of marginal renewable generator and the size of the renewable energy target. Each of these variables is reasonably well defined and as such the REC price forecast can be considered reasonably firm. This means that the net benefits to generators in the form of additional REC payments which is sensitive to the REC price is also reasonably firm.

Table 12 **REC price projections**

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2025	2030
Load follow ing costs $10	$36.52	$39.01	$41.66	$44.49	$47.52	$50.75	$54.20	$57.88	$61.82	$66.02	$70.51	$92.86	$92.86
Load follow ing costs $15	$36.84	$39.35	$42.02	$44.88	$47.93	$51.19	$54.67	$58.39	$62.36	$66.60	$71.13	$92.86	$92.86

Data source: ACIL Tasman modelling

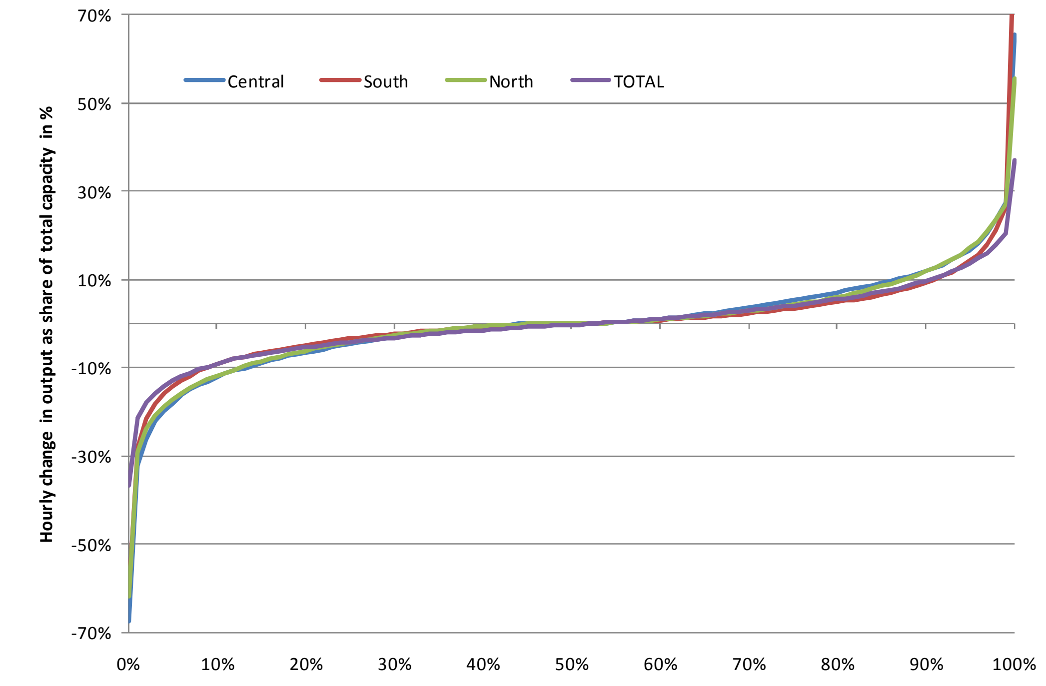
2.7.1 Effects of wind generation in the SWIS

Currently wind makes up less than 5% of total energy generation in the SWIS. Furthermore, exiting farms are geographically dispersed, which decreases the correlation in output by these farms significantly. This can be seen in Chart 17, which shows the hourly change in generation as a ratio of total installed wind farm capacity in different regions and the SWIS as a whole in the year to 31 October 2009. The chart illustrates by how much other market participants are expected to ramp generation up or down due to counter changes in wind output.

The interesting feature is that output from wind farms increases and decreases in a symmetric fashion. More importantly, the chart highlights the fact that wind farms do not decrease their output in a sudden manner. In fact, Chart 18 shows that the output of wind farms dropped by more than of 40% of its capacity only in 0.4% of the time over the 2009 year. There were a number of occurrences where a regions wind farm output dropped by more than 90% within an hour in the 2008 year. These would have been due to wind speeds exceeding the cut-out-speed, which is between 70 and 125 Km/h for most wind farms, rather than a lack of wind.

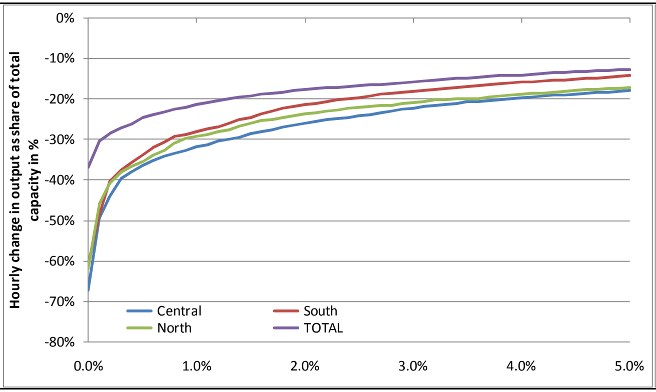
Additionally, the geographic diversity ensures that total wind output across the system hasn't dropped by more than 40% of total wind capacity installed at any given time in 2009. Assuming that these fall off rates remain constant over time, this could expose the SWIS to a maximum drop of around 400MW an hour based on expected installed wind capacity in the system. Nevertheless, the SWIS is also expected to have a 2,000 MW generation capacity based on OCGTs and over 800 MW of capacity in terms of CCGTs by 2017, which we have assumed will be able to pick up any drop off in wind generation.

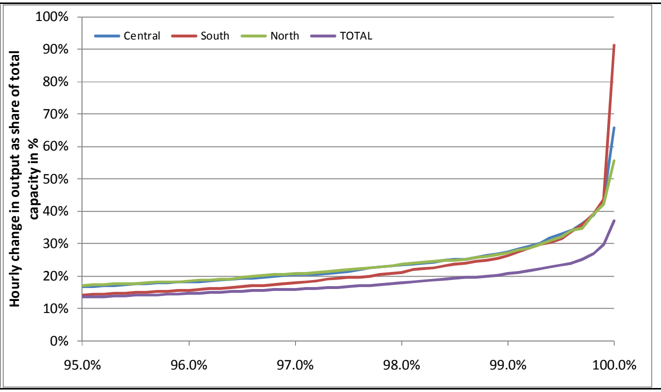
Chart 17 **Change in dispatch duration curve: Hourly change in wind farm dispatch**



Data source: ACIL Tasman modelling

Chart 18 **Change in dispatch duration curve: Hourly change in wind farm dispatch, top/bottom 5%**

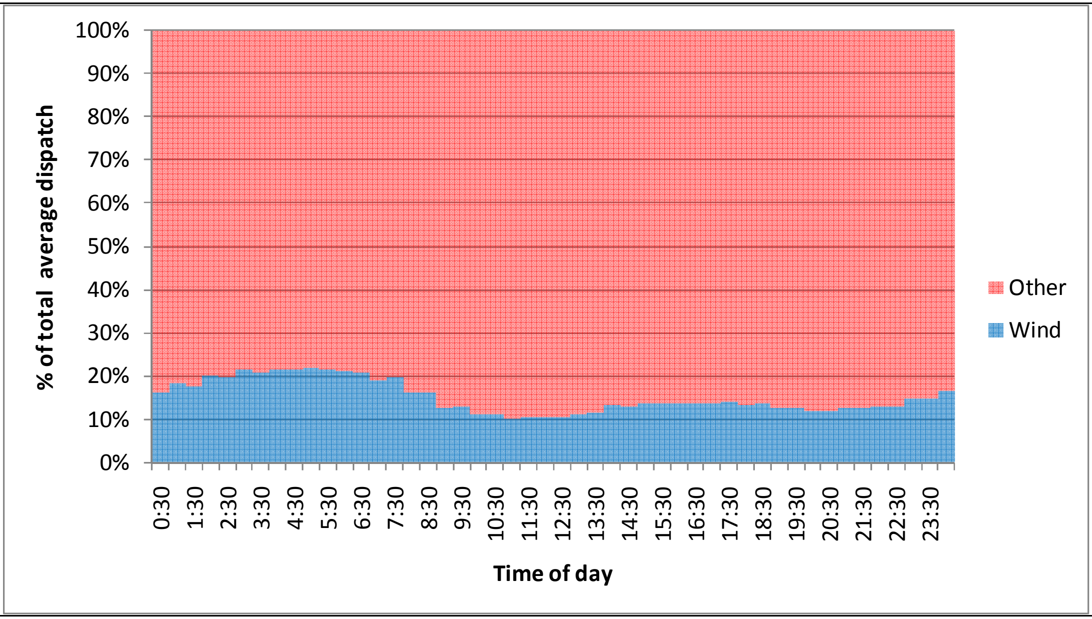




Source: SWIS, 2009

The contribution of wind farms to overnight generation will continue to grow with new wind farms coming online. By 2017, wind generation will contribute on average just under 22% to overnight generation (see Chart 19), which represent around 400 MW of generation. Additionally, ACIL Tasman's modelling shows that wind generation has to be curtailed only around 1% of the time to accommodate the current minimum loading level for the SWIS after 2017.

Chart 19 **Wind generation time of day dispatch in % of total dispatch 2017**



Source: PowerMark output

2.8 Other assumptions

2.8.1 Consumer Price Index

The underlying CPI is assumed to be at 2.5% for the whole modelling period.

2.8.2 New entrant costs

The long run marginal costs (LRMC) are used by ACIL Tasman as a guide as to when and where to bring new entrants into the simulation (as capacity additions assumptions). New entry costs are estimated within a financial model that encompasses assumptions concerning thermal efficiency, the cost of gas, the weighted average cost of capital (WACC) and the capital costs of bringing a plant into commercial operation. The WACC outlined in Table 14 is also used to estimate the NPV of the different scenario outcomes which are evaluated over the next 20 years.

Table 13 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 13 New entry assumptions in 2007/08 dollars

Input assumption	Cogen	Sub-critical coal	CCGT	OCGT	USC	USC-95% CCS	IGCC	IGCC-25% CCS	IGCC-75% CCS
Installed capacity (MW)	160	220	250	150	400	400	400	400	400
Auxiliary requirements	2.40%	7.50%	2.40%	2.40%	7.50%	12.50%	11.00%	15.00%	25.00%
Capacity factor	90%	87%	65%	2%	85%	85%	85%	85%	85%
Thermal efficiency (sent out)	34.10%	36.10%	50.00%	34.00%	44.00%	36.00%	40.00%	38.60%	35.50%
Economic life (years)	30	30	30	30	30	30	30	30	30
Capital cost ($/KW)	1,500	2,350	1,450	1,050	3,200	5,000	3,400	4,200	5,300
Capital cost escalation rate (% of CPI)	90%	90%	90%	90%	90%	90%	90%	90%	90%
Fixed O&M ($/MW/year)	45,600	48,000	17,920	10,500	50,000	75,000	52,000	60,000	72,000
Fixed O&M escalation rate (% of CPI)	100%	100%	100%	100%	100%	100%	100%	100%	100%
Variable O&M ($/MWh)	$0	$1.44	$5.82	$9.00	$1.44	$1.44	$1.44	$1.44	$1.44
Variable O&M escalation rate (% of CPI)	100%	100%	100%	100%	100%	100%	100%	100%	100%

Data source: ACIL Tasman

Table 14 New entrant WACC assumptions

Component	Value
Debt	60%
Inflation	2.50%
Corporate tax rate (effective)	30.00%
Risk free Rate	6.33%
Market Return	12.33%
Market risk premium	6.00%
Cost of debt	9.33%
Gamma	0.50
Asset Beta	0.80
Debt Beta	0.24
Equity Beta	1.62
Expected return on equity	16.08%
Post-tax nominal WACC	9.96%
Post-tax real WACC	7.27%
Pre-tax real WACC	10.09%

Data source: ACIL Tasman

3 Modelling results

3.1 Base Case: Medium growth outlook with no wind in the North region

The Base Case uses the medium load growth and incorporates more new wind capacity in the case with North Link but has no new wind capacity north of Eneabba. The Base Case uses $10.00/MWh load following costs for wind farms and capacity credit allowance of 40% of wind farm capacity.

3.1.1 Assumptions: Base Case

The base case has been designed such that the net market benefits of the proposed North Link can be assessed. Based on this, ACIL Tasman removed all the wind farms in the North region, as these require further network augmentations in order to be able to supply their full capacity into the SWIS. As a result, the interconnector upgrade only captures the benefits of wind farms located south of Eneabba around Emu Downs in the Central region. The construction of these wind farms is contingent on the North Link to make them economically viable. ACIL Tasman has assumed that there will be no significant change in the REC price, as replacement wind farm projects will be built elsewhere in Australia.

The assumed size of the current interconnector can be seen in Table 15. For modelling purposes the North Link upgrade is assumed to match the forecast peak demand in the North region including any new block loads under medium growth outlook.[4]

Table 15 **Interconnector capacity (MW) in the modelling - base case**

Financial year ending	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2025	2030
Without upgrade	145	137	137	155	155	155	155	155	155	155	155	155	155
With upgrade	145	137	137	155	335	337	337	338	339	339	340	343	346

Data source: ACIL Tasman modelling

Another key assumption in the base case scenario is that the new loads in the North region have to be serviced even without the proposed interconnector expansion. As such an additional 160MW new entrant CCGT has been located in the North region to service these loads in the case without North Link.

[4] The Western Power proposed double circuit 330kV transmission line operated initially with one side at 132kV provides in excess of 500MW of capacity – more than adequate for the medium growth scenario.

A summary of the new installed capacity in the base case can be seen in Table 16 and Table 17. Chart 20 and Chart 21 summarise this information in a visual form. It can be seen that the case with North Link has more installed capacity than in the case without North Link. This occurs because there is more wind capacity in the case with North Link and only 40% is allocated capacity credits to meet the capacity requirements which are the same with and without North Link.

Table 16 **New entrant summary: Base Case with North Link**

	2015				2020			
	North region	South region	Central region	Total	North region	South region	Central region	Total
Renewable	0	285	486	771	0	285	486	771
Baseload	0	0	0	0	250	0	250	500
Peaker	100	0	280	380	100	0	910	1,010
Total	100	285	766	1,151	350	285	1,646	2,281
	2025				2030			
	North region	South region	Central region	Total	North region	South region	Central region	Total
Renewable	0	285	486	771	0	285	486	771
Baseload	250	0	990	1,240	250	640	1,830	2,720
Peaker	100	0	1,710	1,810	100	0	2,550	2,650
Total	350	285	3,186	3,821	350	925	4,866	6,141

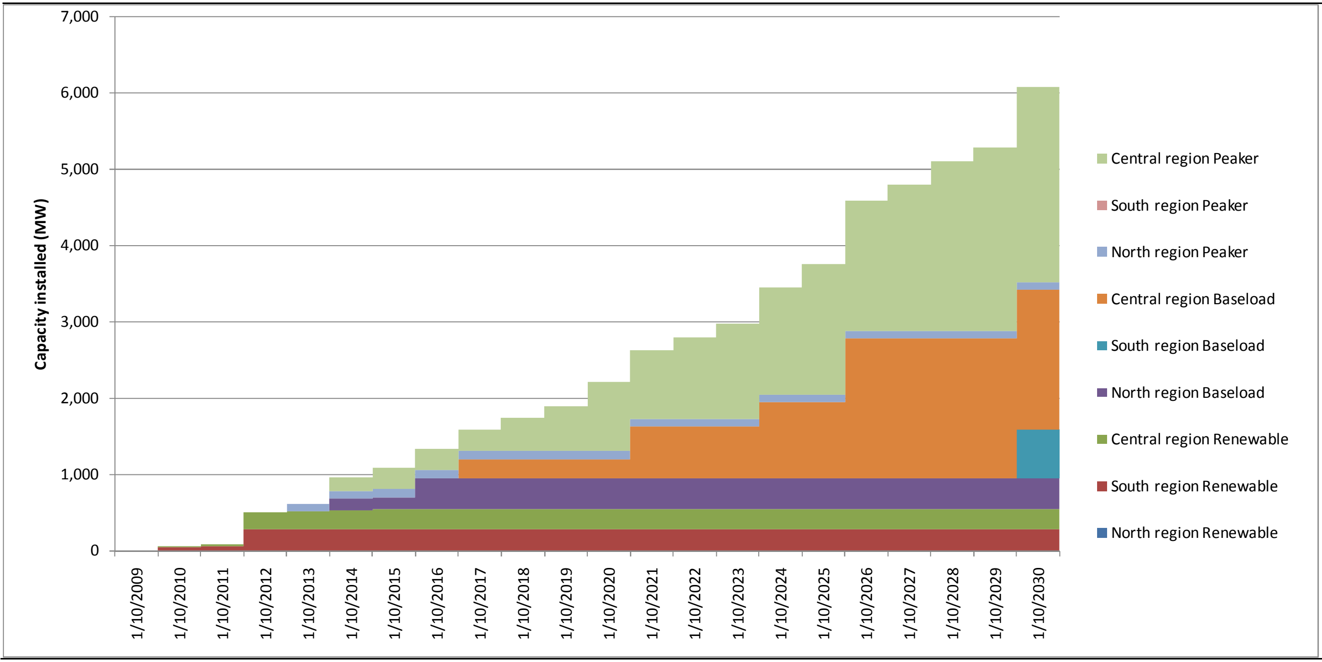
Data source: ACIL Tasman modelling

Table 17 **New entrant summary: Base Case without North Link**

	2015				2020			
	North region	South region	Central region	Total	North region	South region	Central region	Total
Renewable	0	285	256	541	0	285	256	541
Baseload	160	0	0	160	410	0	250	660
Peaker	100	0	280	380	100	0	910	1,010
Total	260	285	536	1,081	510	285	1,416	2,211
	2025				2030			
	North region	South region	Central region	Total	North region	South region	Central region	Total
Renewable	0	285	256	541	0	285	256	541
Baseload	410	0	990	1,400	410	640	1,830	2,880
Peaker	100	0	1,710	1,810	100	0	2,550	2,650
Total	510	285	2,956	3,751	510	925	4,636	6,071

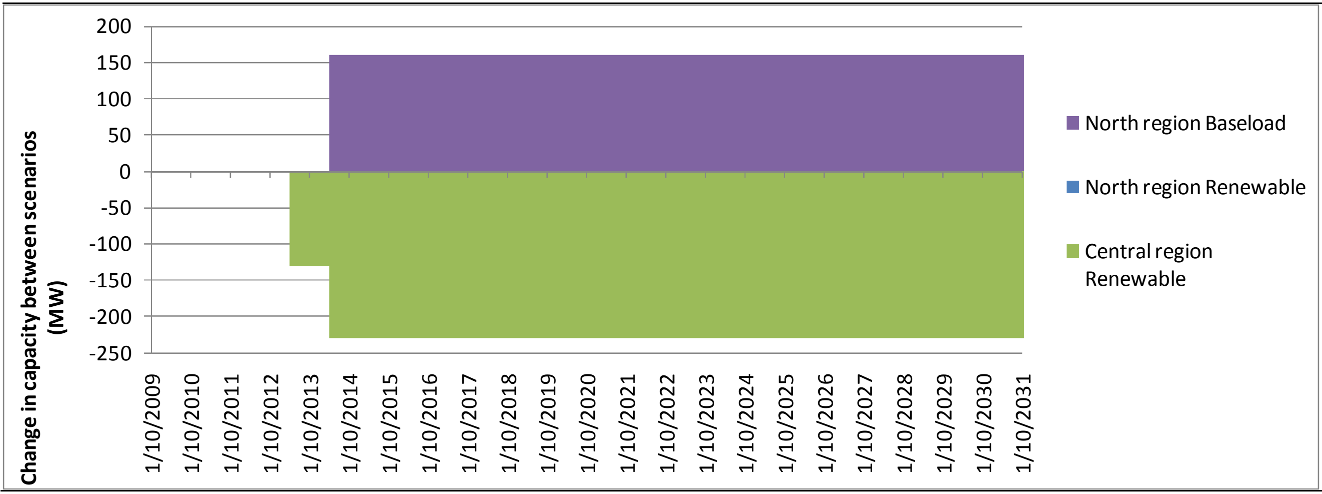
Data source: ACIL Tasman modelling

Chart 20 **New entrant schedule: Base Case**



Data source: ACIL Tasman modelling

Chart 21 **Change in new entrant schedule due to lack of North Link: Base Case**

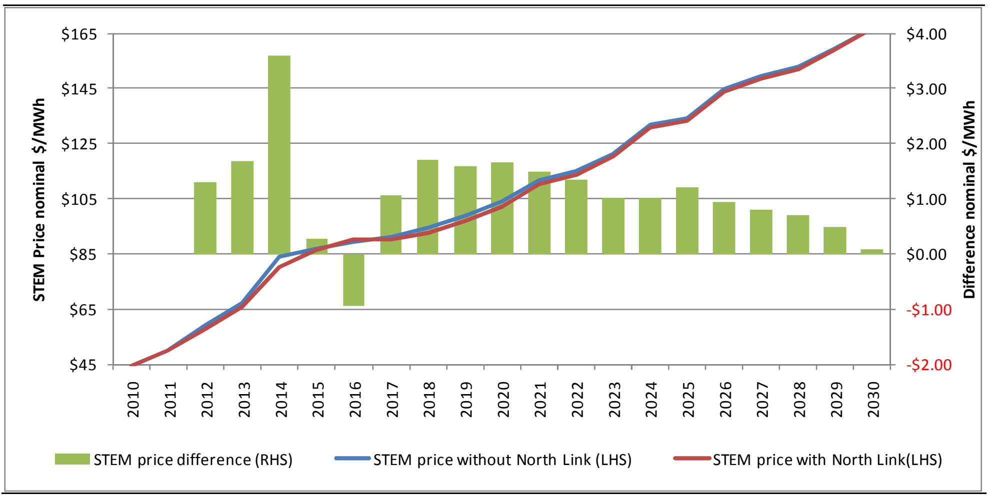


Data source: ACIL Tasman modelling

3.1.2 Result summary: Base Case

Stem prices

Chart 22 **STEM price outcomes: Base Case**



Data source: ACIL Tasman

STEM prices are projected to increase from around $45.00/MWh in 2010 to around $165.00/MWh by 2030 as can be seen in Chart 22. The main reason for the increase is the assumed introduction of the CPRS. The difference in STEM prices between the case with North Link and the case without are generally between $1.00 and 2.00/MWh.

Net market benefits of North Link

Using the above assumptions, the North Link upgrade generates a total net benefit to generators and consumers of $225 million in NPV terms (WACC outlined in Table 14 has been used to discount the annual benefits), as can be seen in Table 18.

The generators capture, in NPV terms, $72 million of these benefits.

On the cost side, generators are faced with $248 million in NPV terms lower generating costs, which are partly offset by higher capital cost of $212 million once the wind farms have been installed. The higher capital spending stems from the difference between the set up cost of CCGTs and wind and the increase in the installed capacity in the case with North Link. Furthermore, the lower capacity factor of wind farms requires more MW installed on the system for the same energy to be generated. In contrast, the variable cost of generating energy utilising wind turbines is much lower once installed resulting in a saving in operating expenditure. As result, the overall cost of generators decreases by $36 million in NPV terms.

After North Link, generators are faced with lower market prices because lower marginal cost wind generation replaces more expensive gas fired generation, and a better utilisation of stations in the Central and South regions. Consequently generators revenue declines by $153 million in NPV terms. On the other hand, wind farm generators increase their revenue by receiving revenue for renewable certificates (RECs) totalling $192 million in NPV terms.

Capacity payments remain the same in both with and without North Link. These are set by the regulator and are adjusted for any oversupply of capacity such that the total moneys for capacity payments remain the same. The steam revenue by generators drops marginally ($3 million in NPV terms) due to a slight reduction in generation by cogeneration units.

Consumers, benefit from the reduced prices in the order of $153 million in NPV terms because of the lower STEM prices.

Table 18 **Result summary: Base Case**

NPV of net benefit of North Link between 2010 and 2030 ($ million)			
Description	**With North Link**	**Without North Link**	**Change due to North Link**
Generation Costs			
Total fixed costs for new entrant plant (capital and fixed O&M)	$1,768	$1,556	$212
Variable costs for all plant (SRMC incl carbon)	$12,410	$12,658	-$248
Cost of generation ($ million)	**$14,178**	**$14,214**	**-$36**
Generation revenue			
STEM Revenue	$13,176	$13,329	-$153
Capacity revenue	$7,253	$7,253	$0
REC revenue	$666	$474	$192
Steam Revenue	$2,294	$2,297	-$3
Total Generation Revenue	**$23,388**	**$23,353**	**$35**
Net Benefit to generators			**$72**
Cost to consumers			
Cost of STEM energy	$13,176	$13,329	-$153
Cost of capacity credits	$7,253	$7,253	$0
Total cost of Wholesale electricity	**$20,429**	**$20,582**	-$153
Net benefit to electricity consumers			**$153**
Total net benefit for generators and consumers			**$225**

Data source: ACIL Tasman

Table 19 **Average generator capacity factors: Base Case**

Station Name	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Albany	36%	36%	36%	36%	36%	36%	36%	36%	36%	36%	36%	36%	36%	36%	36%	36%	36%	36%	36%	36%	36%
Alcoa Kwinana Cogen	36%	33%	34%	42%	51%	52%	52%	52%	53%	53%	54%	39%	27%	32%	37%	37%	44%	50%	50%	52%	53%
Alcoa Pinjarra Cogen	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Alcoa Wagerup Cogen	34%	34%	39%	48%	61%	62%	61%	62%	63%	63%	63%	47%	31%	36%	43%	43%	51%	58%	60%	61%	63%
Bluewaters	83%	85%	89%	85%	84%	86%	81%	80%	81%	81%	83%	84%	85%	88%	89%	89%	90%	90%	90%	90%	90%
BP Cogen	90%	90%	90%	90%	90%	88%	89%	89%	90%	89%	90%	90%	90%	89%	90%	90%	88%	89%	89%	90%	90%
Canning/Melville LFG	96%	94%	94%	96%	93%	95%	95%	95%	95%	96%	96%	95%	96%	95%	96%	95%	96%	96%	95%	96%	94%
Cockburn	60%	59%	60%	60%	62%	63%	62%	61%	58%	59%	59%	60%	59%	58%	59%	58%	59%	58%	56%	56%	57%
Collie	73%	73%	75%	73%	72%	72%	69%	70%	69%	71%	70%	71%	75%	77%	79%	79%	78%	77%	79%	80%	79%
DSM Dummy	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Emu downs	38%	38%	38%	38%	38%	38%	38%	38%	38%	38%	38%	38%	38%	38%	38%	38%	38%	38%	38%	38%	38%
Geraldton	0%	0%	0%	0%																	
Kalgoorlie	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%					
Kalgoorlie Nickel	5%	14%	21%	10%	3%	5%	7%	7%	6%	6%	7%	10%	8%	7%	9%	6%	9%	7%	5%	5%	7%
Kemerton	8%	6%	6%	4%	5%	5%	4%	5%	4%	4%	5%	7%	6%	5%	6%	5%	6%	5%	3%	4%	5%
Kwinana C	24%	23%	26%	24%	23%	24%	25%	23%	20%	20%	21%	24%									
Kwinana GT	0%	0%																			
Kwinana GT 2			17%	15%	14%	16%	16%	14%	11%	11%	12%	17%	13%	11%	14%	12%	15%	10%	8%	8%	10%
Kwinana HEGT		10%	13%	10%	10%	11%	12%	10%	8%	7%	9%	12%	10%	9%	11%	8%	11%	8%	6%	6%	8%
Manjimup Biomass	90%	93%	92%	91%	91%	92%	92%	92%	93%	92%	92%	92%	92%	92%	92%	93%	92%	92%	92%	92%	92%
Muja C	62%	61%	66%	61%	58%	55%	56%	56%	59%	60%	60%	62%	64%	65%	66%	67%	68%				
Muja D	68%	67%	70%	69%	67%	65%	64%	65%	66%	66%	66%	67%	68%	72%	74%	74%	73%	74%	75%	75%	78%
Mungarra	8%	7%	9%	7%	6%	6%	6%	2%	0%	0%	0%	0%	1%	0%	1%	1%					
Neerabup Peaker	2%	2%	2%	1%	2%	2%	2%	2%	2%	2%	2%	2%	2%	1%	1%	0%	1%	0%	0%	0%	0%
New Biomass		77%	78%	78%	78%	78%	78%	78%	78%	78%	78%	79%	78%	79%	78%	78%	78%	78%	78%	78%	77%
New CCGT_CentralB									23%	26%	27%	31%	25%	32%	42%	37%	44%	41%	41%	42%	47%
New CCGT_NorthA								29%	31%	31%	34%	37%	37%	45%	55%	57%	62%	63%	61%	62%	63%
New Peaking Plant_CentralA						1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	0%	0%	0%	0%	0%	0%
New Peaking Plant_CentralC							2%	2%	2%	2%	2%	4%	3%	2%	3%	2%	2%	1%	1%	1%	1%
New Peaking Plant_NorthA					19%	22%	22%	7%	2%	2%	1%	2%	2%	1%	2%	1%	2%	1%	1%	1%	2%
New Solar PV		20%	19%	19%	19%	19%	19%	19%	19%	19%	19%	19%	19%	19%	19%	19%	19%	19%	19%	19%	19%
WIND_Collgar				38%	38%	38%	38%	38%	38%	38%	38%	38%	38%	38%	38%	38%	38%	38%	38%	38%	38%
Newgen Power	33%	35%	42%	36%	40%	52%	62%	66%	68%	69%	70%	72%	73%	48%	17%	13%	15%	12%	8%	9%	11%
Parkeston SCE	11%	18%	24%	14%	7%	9%	11%	12%	10%	10%	11%	13%	12%	11%	13%	10%	12%	11%	9%	9%	10%
Pinjar A B	1%	0%	1%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%						
Pinjar C	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	13%				
Pinjar D	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Pinjarra Alinta Cogen	86%	87%	86%	86%	86%	86%	86%	86%	86%	86%	87%	86%	87%	87%	85%	87%	87%	86%	86%	87%	86%
Tiwest Cogen	89%	88%	89%	88%	87%	87%	89%	89%	87%	90%	88%	89%	89%	89%	88%	88%	89%	89%	92%		
Wagerup Alinta Cogen																					
Wagerup Alinta Peaker	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Walkaway	36%	36%	36%	36%	36%	36%	36%	36%	36%	36%	36%	36%	36%	36%	36%	36%	36%	36%	36%	36%	36%
WIND_Badgingarra				35%	35%	36%	36%	36%	36%	36%	36%	36%	36%	36%	36%	36%	36%	36%	36%	36%	36%
WIND_Grasmere																					
WIND_Milyeannup				39%	39%	39%	39%	39%	39%	39%	39%	39%	39%	39%	39%	39%	39%	39%	39%	39%	39%
WIND_Mumbida																					
WIND_Nilgen						35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%
WIND_Walkaway2																					
Worsley	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Worsley SWCJV	89%	89%	90%	88%	88%	87%	88%	89%	89%	90%	89%	89%	90%	89%	90%	90%	90%	90%	89%	89%	89%

Data source: ACIL Tasman

3.2 Scenario1: No change in new entrants

Scenario 1 is based on medium load growth with the same new plant assumptions in both the with and without North Link (i.e. no additional wind in the with North Link case)

3.2.1 Assumptions: Scenario 1

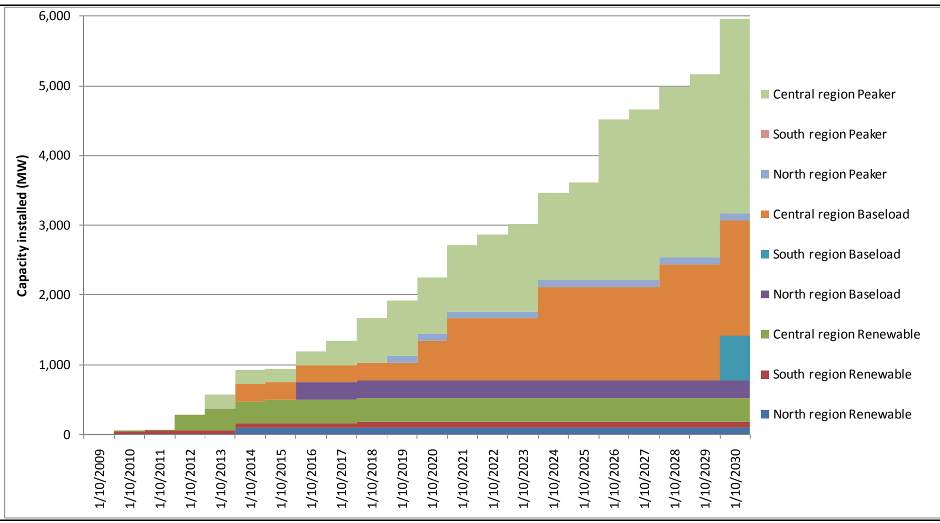
This scenario is estimating the total net benefit of flows on the upgraded interconnector and a better utilisation of low cost generators on the system. This scenario has been set up in a way that all energy is met in all regions and that there is no need to alter the new entrant schedule to accommodate withdrawals of wind generators in the absence of the interconnector. As such less wind capacity has been assumed for this scenario. The assumed new entrants can be seen in Table 20 and Chart 23. The new entrants remain the same in both with and without North Link cases.

Table 20 **New entrant summary: Scenario 1 with and without North Link**

	2015				2020			
	North region	South region	Central region	Total	North region	South region	Central region	Total
Renewable	90	70	336	496	90	100	336	526
Baseload	0	0	250	250	250	0	570	820
Peaker	0	0	200	200	100	0	800	900
Total	90	70	786	946	440	100	1,706	2,246
	2025				**2030**			
	North region	South region	Central region	Total	North region	South region	Central region	Total
Renewable	90	100	336	526	90	100	336	526
Baseload	250	0	1,340	1,590	250	640	1,660	2,550
Peaker	100	0	1,400	1,500	100	0	2,780	2,880
Total	440	100	3,076	3,616	440	740	4,776	5,956

Data source: ACIL Tasman

Chart 23 **New entrant schedule: Scenario 1**



Data source: ACIL Tasman modelling

3.2.2 Result summary: Scenario 1

As there is no change in the new entrant mix, there is no change in the cost to the generators in terms of fixed costs. The increased utilisation of generators with lower SRMC due to the upgrade of the interconnector, results in a $16 million in NPV terms.

The decrease in the generator revenue, due to slightly reduced market prices, of $48 million is captured by the consumers. As a result the total net benefit is equal to the reduction in generation cost of $16 million in NPV terms.

Table 21 **Result summary: Scenario 1**

NPV of net benefit of North Link between 2010 and 2030 ($ million)			
Description	With North Link	Without North Link	Change due to North Link
Generation Costs			
Total fixed costs for new entrant plant (capital and fixed O&M)	$1,779	$1,779	$0
Variable costs for all plant (SRMC incl carbon)	$12,741	$12,757	-$16
Cost of generation ($ million)	**$14,520**	**$14,536**	**-$16**
Generation revenue			
STEM Revenue	$13,502	$13,549	-$48
Capacity revenue	$7,253	$7,253	$0
REC revenue	$633	$633	-$0
Steam Revenue	$2,297	$2,297	-$0
Total Generation Revenue	**$23,686**	**$23,733**	**-$48**
Net Benefit to generators			**-$32**
Cost to consumers			
Cost of STEM energy	$13,502	$13,549	-$48
Cost of capacity credits	$7,253	$7,253	$0
Total cost of Wholesale electricity	**$20,755**	**$20,803**	-$48
Net benefit to electricity consumers			**$48**
Total net benefit for generators and consumers			**$16**

Data source: ACIL Tasman modelling

Scenario 1 demonstrates that most of the net benefit of North Link seems to accrue from a change in generator mix particularly the greater wind capacity which North Link allows to be connected to the SWIS.

3.3 Scenario 2: Full wind benefit

Scenario 2 is based on the medium load growth and incorporates greater new wind capacity, including north of Eneabba, incorporated in the with North Link model run. This is the same as the Base Case with additional new wind capacity north of Eneabba included in the with North Link model run.

3.3.1 Assumptions: Scenario 2

This scenario evaluates the value of all wind generation once the full upgrade of the interconnector has been completed.

This means additional wind farms in the North region, i.e. those north of Eneabba, are included, increasing total wind generation capacity by an additional 184 MW compared with the base case. As for the base case, this scenario assumes that there will be no wind generation in the North region or between Pinjar and Eneabba due to the lack of transmission capability without

North Link. The reduction in wind capacity and the consequent increase in base load generation is reflected in Chart 25.

Table 22 **New entrant summary: Scenario 2 with interconnector**

	2015				2020			
	North region	South region	Central region	Total	North region	South region	Central region	Total
Renewable	184	285	486	955	184	285	486	955
Baseload	0	0	0	0	250	0	250	500
Peaker	100	0	180	280	100	0	810	910
Total	284	285	666	1,235	534	285	1,546	2,365
	2025				2030			
	North region	South region	Central region	Total	North region	South region	Central region	Total
Renewable	184	285	486	955	184	285	486	955
Baseload	250	0	990	1,240	250	640	1,830	2,720
Peaker	100	0	1,610	1,710	100	0	2,450	2,550
Total	534	285	3,086	3,905	534	925	4,766	6,225

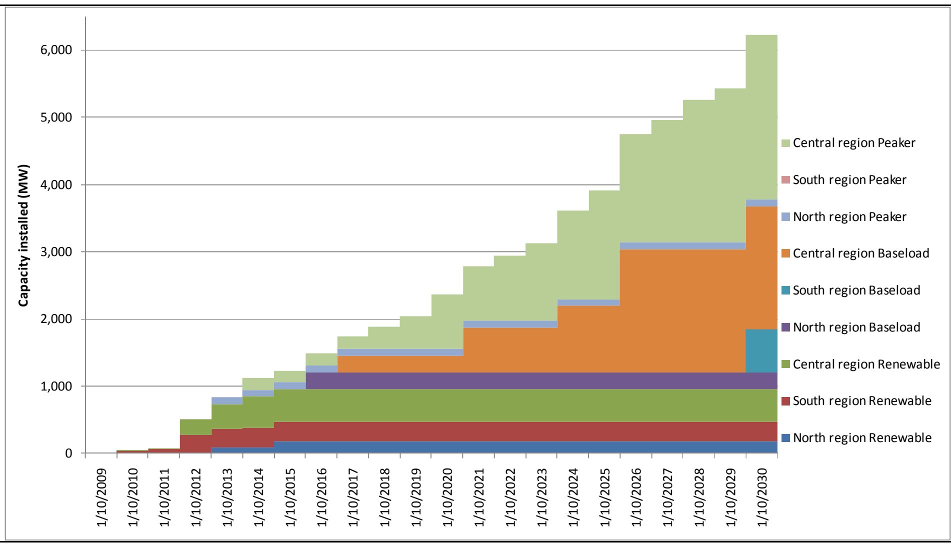
Data source: ACIL Tasman modelling

Table 23 **New entrant summary: Scenario 2 without interconnector**

	2015				2020			
	North region	South region	Central region	Total	North region	South region	Central region	Total
Renewable	0	285	256	541	0	285	256	541
Baseload	160	0	0	160	410	0	250	660
Peaker	100	0	180	280	100	0	810	910
Total	260	285	436	981	510	285	1,316	2,111
	2025				2030			
	North region	South region	Central region	Total	North region	South region	Central region	Total
Renewable	0	285	256	541	0	285	256	541
Baseload	410	0	990	1,400	410	640	1,830	2,880
Peaker	100	0	1,610	1,710	100	0	2,450	2,550
Total	510	285	2,856	3,651	510	925	4,536	5,971

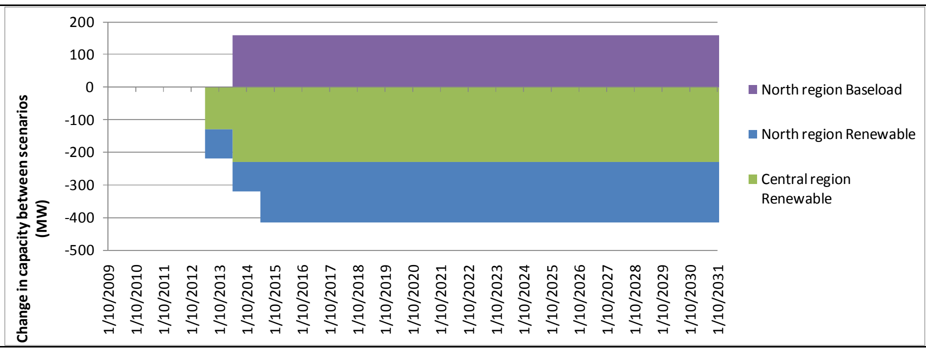
Data source: ACIL Tasman modelling

Chart 24 **New entrant schedule: Scenario 2**



Data source: ACIL Tasman modelling

Chart 25 **Change in new entrant schedule due to lack of North Link: Scenario 2**



Data source: ACIL Tasman modelling

3.3.2 Result summary: Scenario 2

Similarly to the Base case results the main benefit of the interconnector is generated through the additional REC revenue ($340 million in NPV terms) received by wind generators. The increase in capital cost is completely offset by the savings in the cost of generation. The reduced STEM revenue of $380 million in NPV terms by generators is captured by consumers. Furthermore, cogeneration plants lose $9 million in steam revenue due to slightly reduced output. As a result the overall net benefit of the North Link is $331 million in NPV terms in Scenario 2 compared with $225 million in the Base Case.

It is interesting to note that the Base Case has an additional 230MW wind under the with North Link case for a net benefit of $225M. compared with Scenario 2 which has a further 185MW wind in the with North Link case for a further net benefit of $105M which indicates that the net benefits of North

Link are not totally due to the additional wind. For example, Scenario 1 shows a net benefit of $16 million using the same wind capacity with and without North Link. It is interesting to note that it is the reduction in price caused by the extra wind rather than the increase in net revenue of generators which contributes most to the market net benefits.

Table 24 **Result summary: Scenario 2**

NPV of net benefit of North Link between 2010 and 2030 ($ million)			
Description	**With North Link**	**Without North Link**	**Change due to North Link**
Generation Costs			
Total fixed costs for new entrant plant (capital and fixed O&M)	$1,980	$1,508	$472
Variable costs for all plant (SRMC incl carbon)	$12,186	$12,658	-$472
Cost of generation ($ million)	**$14,166**	**$14,166**	**-$0**
Generation revenue			
STEM Revenue	$12,955	$13,335	-$380
Capacity revenue	$7,253	$7,253	$0
REC revenue	$814	$474	$340
Steam Revenue	$2,288	$2,297	-$9
Total Generation Revenue	**$23,310**	**$23,359**	**-$49**
Net Benefit to generators			**-$49**
Cost to consumers			
Cost of STEM energy	$12,955	$13,335	-$380
Cost of capacity credits	$7,253	$7,253	$0
Total cost of Wholesale electricity	**$20,209**	**$20,589**	-$380
Net benefit to electricity consumers			**$380**
Total net benefit for generators and consumers			**$331**

Data source: ACIL Tasman modelling

3.4 Scenario 3: Wind farm capacity credit allowance down to 20%

3.4.1 Assumptions: Scenario 3

This scenario considers the possibility of a reduced capacity credit allowance from the current 40% of capacity down to 20%. Despite the reduced revenue to the Western Australian wind farms, ACIL Tasman's analysis using *RECMark* showed that there is no change in the construction of new wind farms in the SWIS. The estimated REC price will also stay unchanged as it is determined by the marginal cost of wind farms. Due to the decrease in the recognised capacity of wind farms, an additional OCGT unit has to be constructed to meet the regulators reserve capacity requirement.

3.4.2 Result summary: Scenario 3

Compared to the base case, the main change in the outcome is the increase in fixed cost due to a construction of a new peaking plant to meet the regulator's reserve capacity requirement. Overall, the system does not benefit from this additional peaking plant.

The very small difference between the base case and Scenario 3 is because the additional peaker is adding to capital costs and suppressing prices marginally. It shows that reducing the capacity credit allowance to 20% has virtually no affect on the overall net benefits (compare Scenario 3 with the base case)

Table 25 **Result summary: Scenario 3**

NPV of net benefit of North Link between 2010 and 2030 ($ million)			
Description	With North Link	Without North Link	Change due to North Link
Generation Costs			
Total fixed costs for new entrant plant (capital and fixed O&M)	$1,860	$1,648	$212
Variable costs for all plant (SRMC incl carbon)	$12,409	$12,657	-$247
Cost of generation ($ million)	**$14,269**	**$14,305**	**-$36**
Generation revenue			
STEM Revenue	$13,167	$13,317	-$150
Capacity revenue	$7,253	$7,253	$0
REC revenue	$666	$474	$192
Steam Revenue	$2,294	$2,297	-$3
Total Generation Revenue	**$23,379**	**$23,341**	**$39**
Net Benefit to generators			**$74**
Cost to consumers			
Cost of STEM energy	$13,167	$13,317	-$150
Cost of capacity credits	$7,253	$7,253	$0
Total cost of Wholesale electricity	**$20,420**	**$20,570**	-$150
Net benefit to electricity consumers			**$150**
Total net benefit for generators and consumers			**$224**

Data source: ACIL Tasman modelling

3.5 Scenario 4: medium growth, 20% capacity credit and $15/MWh load following cost for wind

Scenario 4 is based on the medium load growth with increased load following costs ($15/MWh) for wind and capacity credits reduced to 20% of wind farm capacity. This is based on the same assumptions as the Base Case except for an increased load following costs of $15.00/MWh and reduced capacity credits for wind farms.

3.5.1 Assumptions: Scenario 4

Scenario 4 extends on Scenario 3 by increasing the cost of load following services to $15/MWh. This resultant increase in the SRMC costs of wind farms had no affect on the relative viability of WA wind farms compared with those in the east. This means no change to the new entrant wind farm profile.

3.5.2 Result summary: Scenario 4

As in scenario 3, the fixed costs increases due to additional OCGT new entrant required to meet the IMO's reserve capacity target. The additional $5/MWh in wind variable O&M by moving from $10 to $15/MWh increased the total variable costs of generating electricity by $90 million over the assessed period. Also, the slight change in the REC price increases the income of wind generators slightly.

As expected, the net benefit of the with and without North link upgrade the reducing capacity credits to 20% of installed capacity and the increase in variable O&M by $5/MWh, will mainly affect the variable cost differential as compared with the base case. The net benefit of adding wind farms to the system will be lower due to their higher SRMCs. The overall NPV of net benefits is shown in Table 26. It shows that both generators and electricity consumers benefit under Scenario 4 with an overall benefit in NPV terms of $207 million. This is less than the net benefit under the base case assumptions of $225 million mainly because of the reduction in the net benefits to generators.

Scenario 4 demonstrates that increasing the load following costs for wind by $5.00/MWh and reducing the capacity credits to 20% of capacity has only a minor impact on the net benefits of North Link. The reduction in net benefits from these changes is estimated at $18 million in NPV terms over 20 years (found by subtracting the total net benefit under Scenario 4 from the total net benefit under the base case).

Table 26 **Result summary: Scenario 4**

NPV of net benefit of North Link between 2010 and 2030 ($ million)			
Description	With North Link	Without North Link	Change due to North Link
Generation Costs			
Total fixed costs for new entrant plant (capital and fixed O&M)	$1,860	$1,648	$212
Variable costs for all plant (SRMC incl carbon)	$12,500	$12,729	-$229
Cost of generation ($ million)	**$14,360**	**$14,377**	**-$18**
Generation revenue			
STEM Revenue	$13,169	$13,318	-$149
Capacity revenue	$7,253	$7,253	$0
REC revenue	$670	$477	$193
Steam Revenue	$2,294	$2,297	-$3
Total Generation Revenue	**$23,386**	**$23,345**	**$41**
Net Benefit to generators			**$59**
Cost to consumers			
Cost of STEM energy	$13,169	$13,318	-$149
Cost of capacity credits	$7,253	$7,253	$0
Total cost of Wholesale electricity	**$20,422**	**$20,571**	-$149
Net benefit to electricity consumers			**$149**
Total net benefit for generators and consumers			**$207**

Data source: ACIL Tasman modelling

3.6 Scenario 5: High load growth

Scenario 5 is based on the high load growth and incorporates more new wind capacity in the case with North Link than without but with no new wind north of Eneabba. Scenario 5 uses $10.00/MWh load following costs for wind farms and capacity credit allowance of 40% of wind farm capacity the same as the Base Case.

3.6.1 Assumptions: Scenario 5

The high load growth scenario assumes a higher energy and demands compared to the base case (see Table 2 and Table 3). The strong energy and demand growth in the North region is manly a result of additional block loads assumed in the region. As in the base case, this scenario assumes no new wind generation in the North region, in order to isolate the benefits of the North Link assessed in the report.

Compared to the base case the high growth scenario has significantly more generation new entrants in order to meet the regulator's reserve capacity targets applied to the higher load forecast. No additional wind generation is added in this scenario over the base case. A summary of the modelled new entrant schedule comparing the with and without North Link outcomes can be seen in Table 27 and Table 28.

Table 27 **New entrant summary: Scenario 5 with North Link**

	2015				2020			
	North region	South region	Central region	Total	North region	South region	Central region	Total
Renewable	0	285	486	771	0	285	486	771
Baseload	500	0	250	750	500	0	860	1,360
Peaker	150	0	280	430	300	0	790	1,090
Total	650	285	1,016	1,951	800	285	2,136	3,221
	2025				**2030**			
	North region	South region	Central region	Total	North region	South region	Central region	Total
Renewable	0	285	486	771	0	285	486	771
Baseload	500	0	1,590	2,090	500	1,760	1,590	3,850
Peaker	300	0	1,630	1,930	300	0	2,380	2,680
Total	800	285	3,706	4,791	800	2,045	4,456	7,301

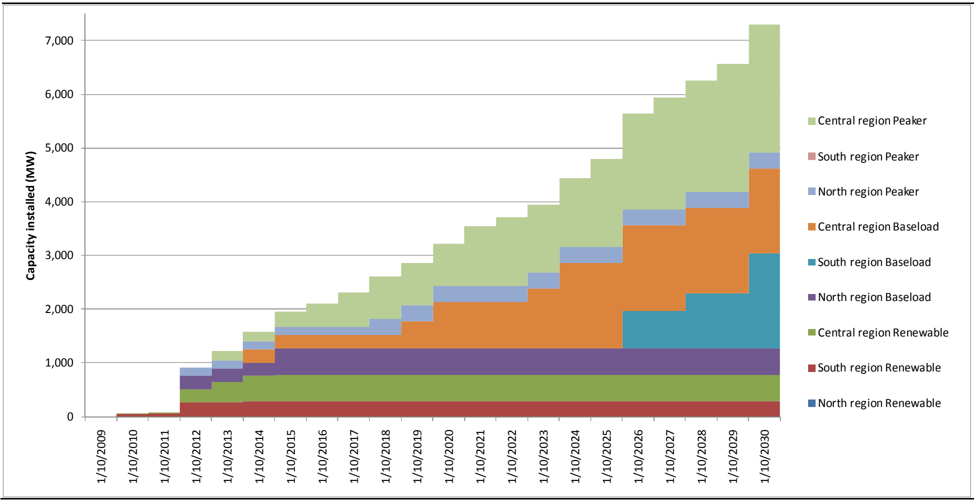
Data source: ACIL Tasman modelling

Table 28 **New entrant summary: Scenario 5 without North Link**

	2015				2020			
	North region	South region	Central region	Total	North region	South region	Central region	Total
Renewable	0	285	256	541	0	285	256	541
Baseload	660	0	250	910	660	0	860	1,520
Peaker	150	0	280	430	300	0	790	1,090
Total	810	285	786	1,881	960	285	1,906	3,151
	2025				**2030**			
	North region	South region	Central region	Total	North region	South region	Central region	Total
Renewable	0	285	256	541	0	285	256	541
Baseload	660	0	1,590	2,250	660	1,760	1,590	4,010
Peaker	300	0	1,630	1,930	300	0	2,380	2,680
Total	960	285	3,476	4,721	960	2,045	4,226	7,231

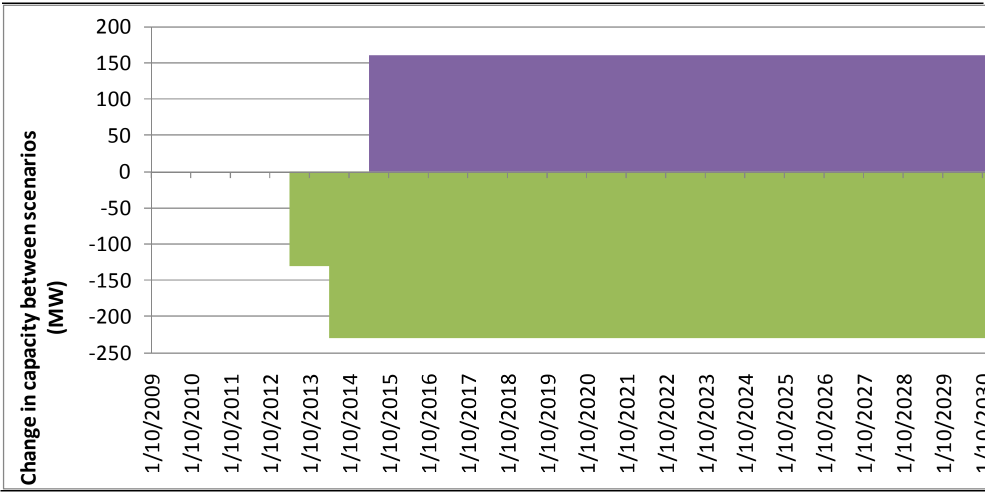
Data source: ACIL Tasman modelling

Chart 26 **New entrant schedule: Scenario 5**



Data source: ACIL Tasman modelling

Chart 27 **Change in new entrant schedule due to lack of North Link: Scenario 5**



Data source: ACIL Tasman modelling

The size of the interconnector[5] has been increased to match the additional block loads in the North region. The assumed sizes of the assumed interconnector for the high growth case can be seen in Table 29.

[5] The Western Power proposed double circuit 330kV transmission line operated with both sides at 330kV provides in excess of 700MW of capacity – more than adequate for the high load scenario.

Table 29 **Interconnector capacity (MW): Scenario 5**

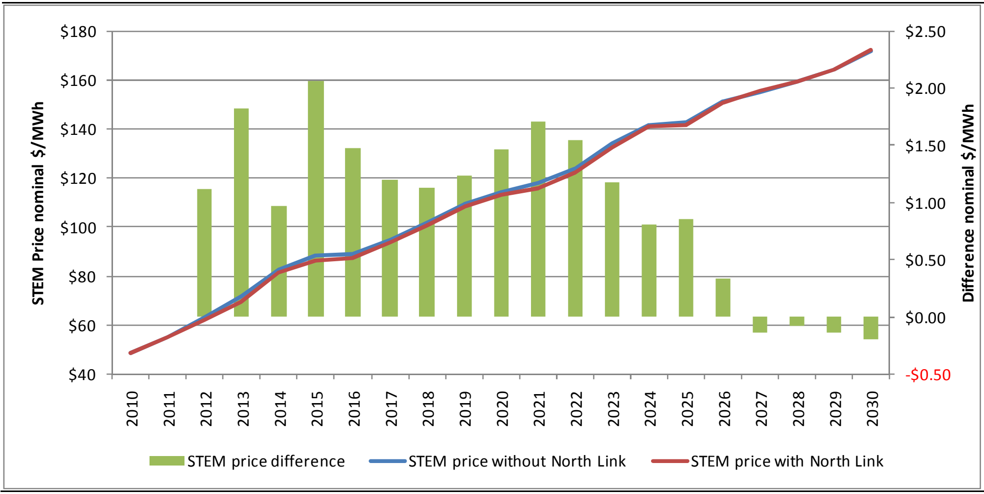
Financial year ending	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2025	2030
Without upgrade	145	137	137	155	155	155	155	155	155	155	155	155	155
With upgrade	145	137	333	476	508	541	573	605	606	607	608	613	618

Data source: ACIL Tasman modelling

3.6.2 Result summary: Scenario 5

Under Scenario 5 the STEM price reduces with the building of North Link as seen in Chart 28. The lower STEM price in the case with North Link is because of lower operating costs with the greater wind farm capacity and less CCGT capacity. The decline electricity price provides a net benefit to consumers of $149 million in NPV terms over 20 years (see Table 30).

Chart 28 **STEM price outcomes: Scenario 5**



Data source: ACIL Tasman modelling

As shown in Table 30, overall net benefit in NPV terms over the coming 20 years from the North Link under Scenario 5 is $236 million. Both generators and consumers are better off by $87 million and $149 million respectively.

The high load growth in Scenario 5 increases the overall net market benefits compared with medium growth in the base case. The overall increase is however relatively modest at $11 million in NPV terms over 20 years. (compare Scenario 5 results in Table 30 with base case results in Table 18).

Table 30 **Result summary: Scenario 5**

NPV of net benefit of North Link between 2010 and 2030 ($ million)			
Description	With North Link	Without North Link	Change due to North Link
Generation Costs			
Total fixed costs for new entrant plant (capital and fixed O&M)	$2,459	$2,231	$227
Variable costs for all plant (SRMC incl carbon)	$14,453	$14,724	-$271
Cost of generation ($ million)	**$16,912**	**$16,956**	**-$44**
Generation revenue			
STEM Revenue	$13,922	$14,071	-$149
Capacity revenue	$7,253	$7,253	$0
REC revenue	$666	$474	$192
Steam Revenue	$2,300	$2,299	$1
Total Generation Revenue	**$24,141**	**$24,097**	**$44**
Net Benefit to generators			**$87**
Cost to consumers			
Cost of STEM energy	$13,922	$14,071	-$149
Cost of capacity credits	$7,253	$7,253	$0
Total cost of Wholesale electricity	**$21,175**	**$21,325**	-$149
Net benefit to electricity consumers			**$149**
Total net benefit for generators and consumers			**$236**

Data source: ACIL Tasman modelling

3.7 Scenario 6: High growth, 20% capacity credit and $15/MWh load following cost for wind

Scenario 6 is based on the high load growth with increased load following costs ($15/MWh) and capacity credits reduced to 20% of wind farm capacity. The main assumptions changes compared with the Base Case are the higher load forecast and an increased load following costs of $15.00/MWh for wind farms and reduced capacity credits for wind farms from 40% 20% of capacity.

3.7.1 Assumptions: Scenario 6

This scenario evaluates a $5 increase in the SRMC of wind turbines due to an assumed increase in load following costs from $10/MWh in scenario 5 to $15/MWh in this scenario. In addition it has been assumed that there is a reduction in capacity credits to wind generators from 40% to 20% of installed capacity.

3.7.2 Result summary: Scenario 6

Compared with Scenario 5, the NPV of the fixed costs increases due to an additional OCGT unit to meet the IMO's reserve capacity requirement given the reduced capacity credits provided by wind farms. Furthermore, the variable costs increase as well due to the additional payment by wind farms for load following services.

The results for Scenario 6 are very similar are similar to Scenario 5. Table 31 shows that, like Scenario 5, both generators ($71m) and consumers ($148m) have net benefits from the construction of North Link giving an overall net market benefit of $219 million in NPV terms over 20 years.

Scenario 6 demonstrates that increasing the load following costs for wind from $10 to 15/MWh and reducing the capacity credits from 40% to 20% of capacity causes only a minor reduction in the net benefits of North Link. The reduction in net benefits from these changes is estimated at $19 million in NPV terms over 20 years (found by subtracting the total net benefit from Scenario 6 in Table 31 from the total net benefit from Scenario 5 in Table 30).

Table 31 **Result summary: Scenario 6**

NPV of net benefit of North Link between 2010 and 2030 ($ million)			
Description	**With North Link**	**Without North Link**	**Change due to North Link**
Generation Costs			
Total fixed costs for new entrant plant (capital and fixed O&M)	$2,551	$2,323	$227
Variable costs for all plant (SRMC incl carbon)	$14,543	$14,796	-$252
Cost of generation ($ million)	**$17,094**	**$17,119**	**-$25**
Generation revenue			
STEM Revenue	$13,916	$14,064	-$148
Capacity revenue	$7,253	$7,253	$0
REC revenue	$671	$477	$193
Steam Revenue	$2,300	$2,299	$1
Total Generation Revenue	**$24,139**	**$24,093**	**$46**
Net Benefit to generators			**$71**
Cost to consumers			
Cost of STEM energy	$13,916	$14,064	-$148
Cost of capacity credits	$7,253	$7,253	$0
Total cost of Wholesale electricity	**$21,169**	**$21,317**	-$148
Net benefit to electricity consumers			**$148**
Total net benefit for generators and consumers			**$219**

Data source: ACIL Tasman modelling

4 Summary of market modelling results

Scenario 2 which has the largest wind turbine capacity has the largest total net benefits. Only in Scenario 2 are new wind farms allowed in North region.

The lowest net benefits are in Scenario 1 where there is no change in installed plant with and without North Link.

Increasing load following costs for wind from $10 to 15/MWh and reducing capacity credits from 40% to 20% of capacity for wind makes a $17 to 18 million difference to the total net benefits (compare the Base Case with Scenario 4 and Scenario 5 with Scenario 6)

The load growth has an $11 to 12 millionaffect on total net benefits (compare the Base Case with Scenario 5 or Scenario 4 with Scenario 6).

In summary the more wind generation which able to enter because of the enhanced transmission capability then the greater the net market benefits from the augmentation. Higher load growth has the relatively minor affect of increasing the net benefits marginally. Increased costs of load following and reduced capacity credits for wind farms push down the net benefits of enhanced transmission capacity but again only marginally.

Table 32 **Scenarios summary table**

Description	Base case	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5	Scenario 6
Generation Costs							
Total fixed costs for new entrant plant (capital and fixed O&M)	$212	$0	$472	$212	$212	$227	$227
Variable costs for all plant (SRMC incl carbon)	-$248	-$16	-$472	-$247	-$229	-$271	-$252
Cost of generation ($ million)	**-$36**	**-$16**	**-$0**	**-$36**	**-$18**	**-$44**	**-$25**
Generation revenue							
STEM Revenue	-$153	-$48	-$380	-$150	-$149	-$149	-$148
Capacity revenue	$0	$0	$0	$0	$0	$0	$0
REC revenue	$192	-$0	$340	$192	$193	$192	$193
Steam Revenue	-$3	-$0	-$9	-$3	-$3	$1	$1
Total Generation Revenue	**$35**	**-$48**	**-$49**	**$39**	**$41**	**$44**	**$46**
Net Benefit to generators	**$72**	**-$32**	**-$49**	**$74**	**$59**	**$87**	**$71**
Cost to consumers							
Cost of STEM energy	-$153	-$48	-$380	-$150	-$149	-$149	-$148
Cost of capacity credits	$0	$0	$0	$0	$0	$0	$0
Total cost of Wholesale electricity	-$153	-$48	-$380	-$150	-$149	-$149	-$148
Net benefit to electricity consumers	**$153**	**$48**	**$380**	**$150**	**$149**	**$149**	**$148**
Total net benefit for generators and consumers	**$225**	**$16**	**$331**	**$224**	**$207**	**$236**	**$219**

Data source: ACIL Tasman modelling

5 Revenue and costs of a wind farm in North Country

5.1 Wind farm revenue

Wind farms in WA generate revenue from three sources and these are:

- wholesale electricity sales through bilateral contracts and STEM trading
- sale of Renewable Energy Certificates (RECs)
- provision of capacity credits of 40% of installed capacity

Revenue from wholesale electricity sales will come through bilateral contracts, usually tied to the provision of REC's, and STEM trading. The future average wholesale electricity prices from *WA PowerMark* are adjusted to a wholesale dispatch weighted price for wind generation in North Country my multiplying by 0.95. The downward adjustment of the average wholesale price for electricity reflects the fact that there is a tendency for wind generation in North Country to be higher overnight when prices are lower. The wind farm dispatch is then multiplied by the dispatch weighted price for wind to provide a projection of the revenue from electricity sales. Wind farms in North Country normally achieve an annual capacity factor of over 40% which is high by Australian and overseas experience.

ACIL Tasman uses its renewable energy market model *RECMark* to determine the future REC price. The results for this modelling are shown in Table 12 on Page 29. The revenue from REC is the REC price multiplied by dispatch

The revenue from the provision of capacity credits which currently are 40% of installed capacity. The capacity price is shown in Table 10 on Page 25. The revenue from capacity credits is the price for capacity multiplied by the number of capacity credits which for wind farms is 40% of installed capacity.

The resultant revenue estimates are shown in Table 33.

Table 33 **Revenue from wind farms (real 2009-10 $/MWh)**

Financial year ending 30 June	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2025	2030
Wholesale electricity revenue $/MWh	$46.61	$52.42	$57.18	$67.25	$70.89	$70.84	$69.71	$70.40	$72.16	$74.23	$86.44	$96.17
REC revenue $/MWh	$38.06	$39.65	$41.31	$43.05	$44.86	$46.74	$48.69	$50.74	$52.86	$55.08	$70.77	$69.05
Capacity revenue $/MWh	$40.16	$36.34	$52.59	$49.95	$47.39	$45.25	$42.09	$39.38	$37.15	$35.20	$32.77	$32.61
Total estimated revenue $/MWh	$124.83	$128.41	$151.08	$160.25	$163.13	$162.83	$160.49	$160.52	$162.18	$164.52	$189.98	$197.83

Data source: ACIL Tasman modelling and analysis

5.2 Wind farm costs

Wind farm costs are mainly the initial capital cost and the fixed O&M costs. For WA we have also assumed that wind farms will be required to meet a load following cost of between $10.00 and $15.00/MWh.

ACIL Tasman estimates the capital cost of a wind farm in WA at $2,700/KW and an annual fixed O&M at $30,000 in 2009-10. Variable O&M is assumed at $1.00/MWh plus load following costs of between $10.00 and $15.00/MWh again in 2009-10.

Applying a real post tax WACC of 7.27% and based on the load following costs of $15.00/MWh the life cycle cost (or LRMC) of wind farms in North Country is estimated at $105.48/MWh in 2009-10 $.

6 Cost of isolated generation

This section of the report examines the possible benefits accruing to potential major loads of having access to the network because of North Link rather than relying on isolated generation.

The key benefits of network connection come from having access to a large and more diverse generation plant mix, economies of scale through larger generation units, more diverse and secure fuel supply and greater opportunities to purchase low cost energy in off peak times. High levels of reliability would be provided by network connection although this can be matched in an isolated generation situation by carrying adequate plant redundancy and having enhanced fuel security.

The net benefit to potential new loads is the difference between the cost of isolated generation and the cost of energy purchases out of the WEM plus network connection costs and charges. In this section we estimate the value the cost of isolated on-site generation and compare this to the whole cost of energy (including cost of capacity). The network costs and charges are not considered in this report.

The cost of providing reliable power to an isolated load must make provision for planned and forced outages. For the purpose of this analysis we have assumed that the load must be supplied at 99.9% reliability.

6.1 Isolated generation assumptions

6.1.1 Characteristics of major block load

The key characteristics of the major block load are shown in Table 34.

Table 34 **Assumed major block load characteristics**

	MW	GWh	Load factor
Peak load	145		
Normal running load	140		
Annual average load	120	1051	83%
Overall reliability of supply	99.90%		

Data source: ACIL Tasman assessment

6.1.2 Isolated generation configuration

It has been assumed that gas fired combined cycle gas turbines (CCGTs) would be used to provide the base load energy and open cycle gas turbines (OCGTs) would be used as back-up for outages of the CCGT plant. The gas to the plant would be supplied via a lateral pipeline from the Dampier to Bunbury natural gas pipeline (DBNGP) with short term fuel backup provided by on site oil tanks. Around 2% of the energy is assumed to be supplied by oil.

ACIL Tasman believes that the load characteristics as outlined in Table 34 would be best met by a combination of three 50MW CCGTs and a single 35MW OCGT. This combination assumes a 90% availability of the CCGTs.

On this basis the OCGT would need to run approximately 30% of the time while the CCGTs would need to achieve an average capacity factor of around 73%.

The assumed plant configuration is shown in Table 35.

Table 35 **Assumed plant configuration**

	Unit size (MW)	Number of units (No)	Installed capacity (MW)	Energy supplied (GWh)	Inferred capacity factor (%)
CCGT	50	3	150	959	73%
OCGT	35	1	35	92	30%
Total			185	1051	

Data source: ACIL Tasman assessment

6.1.3 Isolated plant characteristics

The CCGTs and OCGT have been assumed to have the characteristics in 2010 as shown in Table 36. The capital and operating costs of these isolated plants are noticeably higher than plant on the SWIS which reflects the isolated plants location and smaller size compared with plant in the SWIS. ACIL Tasman assess that in general the isolated plant costs are around 20% higher.

Table 36 **Key isolated plant characteristics in 2010**

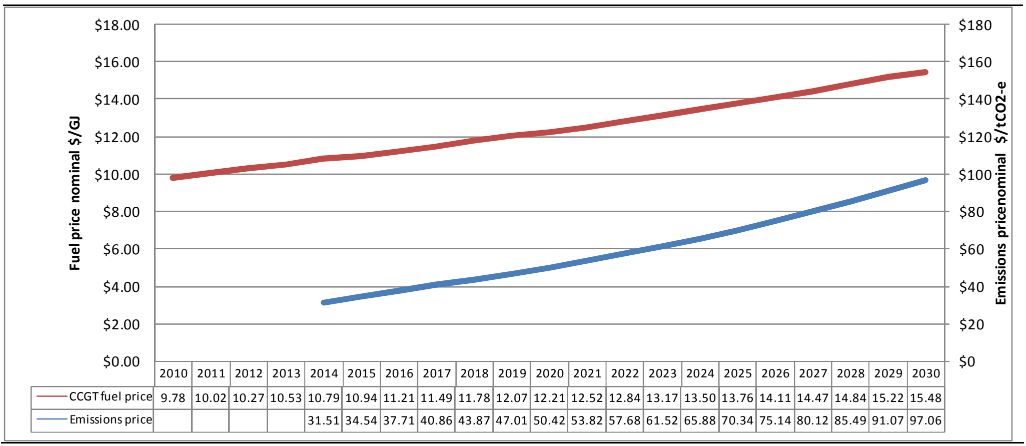
Input assumption	CCGT	OCGT
Installed capacity (MW)	50	35
Auxiliary requirements	2.40%	2.00%
Capacity factor	73%	30%
Thermal efficiency (sent out)	45.00%	32.00%
Economic life (years)	30	30
Capital cost ($/KW)	1,772	1,266
Capital cost escalation rate (% of CPI)	90%	90%
Fixed O&M ($/MW/year)	22,814	19,096
Fixed O&M escalation rate (% of CPI)	100%	100%
Variable O&M ($/MWh)	$7.41	$11.46
Variable O&M escalation rate (% of CPI)	100%	100%

Data source: ACIL Tasman assessment

6.1.4 Fuel and emissions costs

These plant characteristics are then combined in a discounted cash flow analysis with emissions costs, fuel costs and the weighted average cost of capital to determine the cost per MWh to produce power from the isolated plants. The delivered fuel costs and emissions prices assumptions are summarised in Chart 29. The delivered fuel cost include allowance for transport from the DBNGP to the station of $0.40/GJ.

Chart 29 **Fuel (nominal $/GJ delivered) and emissions prices (nominal $/tonne CO2-e) used to calculate isolated generation costs**



	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
CCGT fuel price	9.78	10.02	10.27	10.53	10.79	10.94	11.21	11.49	11.78	12.07	12.21	12.52	12.84	13.17	13.50	13.76	14.11	14.47	14.84	15.22	15.48
Emissions price					31.51	34.54	37.71	40.86	43.87	47.01	50.42	53.82	57.68	61.52	65.88	70.34	75.14	80.12	85.49	91.07	97.06

Source: Fuel prices assessed by ACIL Tasman. Emissions prices are from the Federal Government CPRS White Paper and ACIL Tasman projection based on 2020 and interim targets of -5% compared with 2000.

6.1.5 WACC estimate

The WACC for isolated generation is shown in Table 37. This is slightly higher than the WACC calculated for WEM new entrants with higher debt basis point premium of 450 compared with 300 assumed for the WEM.

Table 37 **WACC for isolated generator**

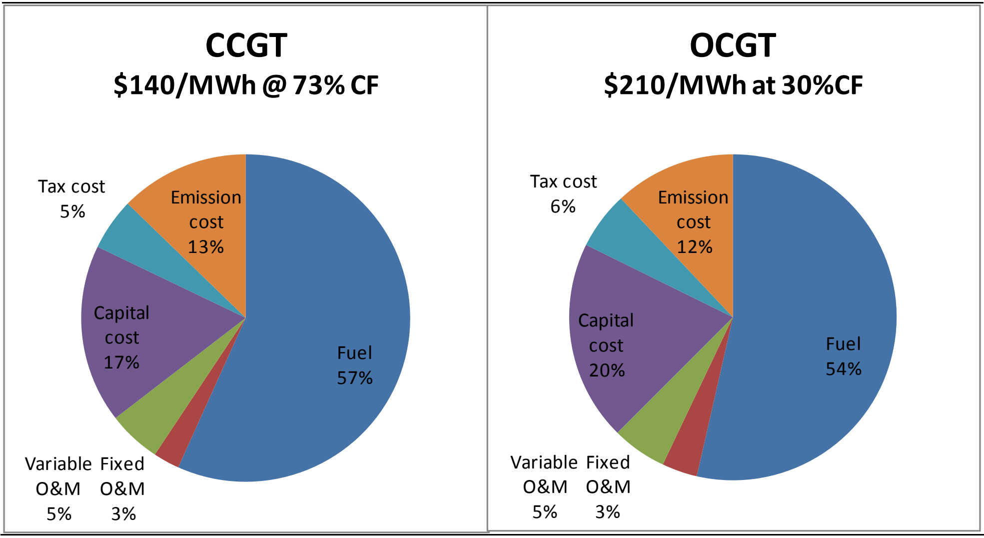
Item	Estimate
Liabilities	100%
Debt	60%
Equity	40%
Risk free RoR	6.33%
Market risk premium	6%
Market RoR	12.33%
Corporate tax rate	30%
Effective tax rate	22.5%
Imputation adjusted tax	15.0%
Debt basis point premium	450
Cost of debt	10.83%
Gamma	0.50
Asset Beta	0.80
Debt Beta	0.36
Equity Beta	1.44
Required return on equity	14.99%
Inflation	2.50%
Post-tax (Officer) nominal WACC	10.27%
Post-tax (Officer) real WACC	7.58%

Data source: ACIL Tasman analysis

6.2 Results of DCF analysis

The DCF analysis provides the electricity production cost which includes a risk adjusted market return to the generator. In the case of isolated gas fired generation to reliably supply block mining loads in North Country the costs would be as shown in Chart 30. Clearly a CCGT operating at 73% capacity factor has much lower long run marginal costs (LRMC) per MWh than an OCGT operating at 30% capacity factor. The costs increase marginally in real terms over time because of an assumed real increase in the cost of emissions. Other costs remain the same or decline marginally in real terms over time.

Chart 30 **Costs for isolated generation from CCGT and OCGT in North Country in 2010 (Real 2010 $/MWh)**



Data source: ACIL Tasman new entrant modelling based on ACIL Tasman assumptions

Now weighting the CCGT and OCGT prices to account for the contribution to total energy of each of the two plant types gives an overall cost of $146.13/MWh supplied (see Table 38).

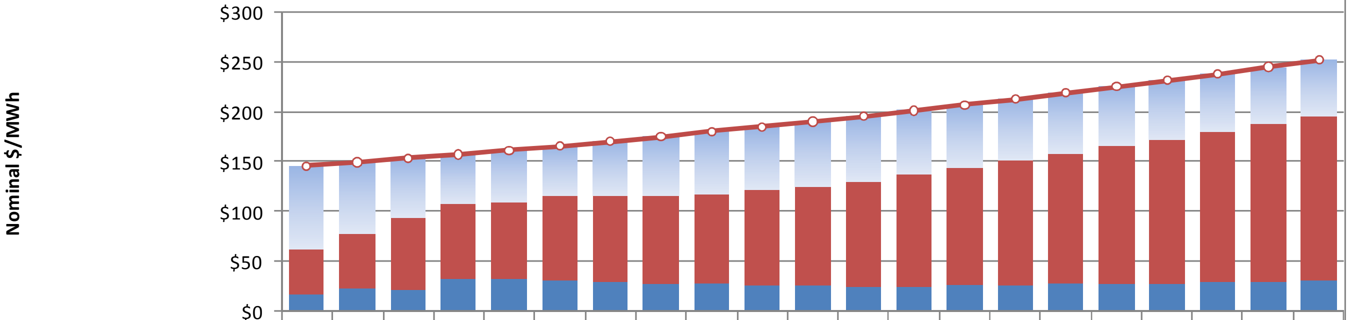
Table 38 **Overall cost of isolated generation in 2010**

	Production (GWh sent-out)	LRMC ($/MWh sent-out)
CCGT	959	$140.00
OCGT	92	$210.00
Overall Cost	1051	**$146.13**

Data source: ACIL Tasman analysis

The comparison with WEM wholesale prices is provided in Chart 31. The final step in assess the benefits or otherwise of grid connection compared with isolated generation would be to assess whether the amount available for the network costs shown in Chart 31 is more or less than network connection costs and charges. The difference between the amount available for network costs and the network connection costs and charges would be a measure of the net benefit or otherwise of grid connection.

Chart 31 **Comparison between isolated generation costs and WEM wholesale costs (nominal $/MWh)**



	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Amount available for Network	83.95	72.06	59.92	49.83	51.24	50.34	53.97	59.43	62.46	63.80	64.56
WEM Energy Cost	44.33	53.96	71.60	74.85	78.10	84.40	86.42	87.17	90.27	94.84	100.02
WEM Capacity Cost	17.95	23.87	22.14	32.85	32.18	31.28	30.32	28.91	27.69	26.82	26.05
Isolated cost of generation	146.23	149.89	153.66	157.53	161.52	166.02	170.71	175.50	180.42	185.45	190.62

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Amount available for Network	65.16	64.34	63.04	61.59	60.12	59.42	58.82	57.95	57.07	55.71
WEM Energy Cost	105.69	111.68	118.02	124.71	131.78	137.99	144.49	151.30	158.43	165.89
WEM Capacity Cost	25.21	25.62	26.33	27.00	27.44	28.22	28.78	29.48	30.04	30.91
Isolated cost of generation	196.06	201.65	207.39	213.29	219.34	225.63	232.09	238.73	245.53	252.51

Data source: ACIL Modelling and analysis