SDDP Modelling of

Carbon Dioxide Emissions

from Electricity Generation

25th November 2008

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For
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Contents

Executive Summary

The SDDP stochastic optimal dispatch model has been used to analyse the New Zealand power system over the period 2009 to 2032, for five scenarios of carbon costs: 0, 20, 40, 60 and 80 \$/tonne CO_2. Optimal generation commissioning programs were determined using the Electricity Commission's GEM model, and these have been simulated in detail using SDDP.

Total annual average electricity sector CO_2 emissions are shown in Figure 1. From an initial eight million tonnes per year, emissions rise by 2032 to over 13 million tonnes per year in the scenario with no carbon charges, but fall to 4.7 million tonnes with 60 or 80 \$/tonne CO_2 costs.

An emissions factor has been defined to assist in determining the quantity of emission credits required to compensate an electricity consumer for the price effects of carbon costs on electricity prices. The following definition is used:

$$\text{Emissions Factor} = \frac{\text{SRMC with carbon cost - SRMC without carbon cost}}{\text{Carbon cost}}$$

where SRMC = Short Run Marginal Cost

Figure 2 and Table 1 show that North Island emissions factors are generally declining, and have similar values for all scenarios except the \$20/t CO2 case which has values which are somewhat different for a part of the study period. South Island emissions factors are similar to those for the North Island.

Interpretation of these results must be within the context of the SDDP least cost dispatch methodology. The results of this model can be expected to differ from actual market outcomes. The causes of this difference include the following:

1. SRMC calculated by SDDP will generally provide a lower bound on those observed in the market. Because an overall system wide optimum strategy is calculated by SDDP, other strategies will result in either the same or higher costs
2. SDDP is risk neutral – it seeks to minimise expected system costs without regard to the volatility of revenues or prices. Generation companies are not risk neutral, and so expected costs are likely to be increased.
3. Marketing strategies will increase market prices above SRMC. This is due to the ability of generation companies to achieve prices above the SRMC of their plant, depending on market conditions.

The use of SRMC values is recommended for many purposes, rather than the LRMC of a particular generation technology. This is because the use of optimisation techniques to determine both the optimal generation commissioning program and system dispatch will result in consistent results. The Electricity Commission's GEM model has been used to determine optimal plant commissioning dates, and SDDP has been used to calculate the optimal dispatch, given this commissioning program. New plant will be commissioned in the optimisation only when SRMC is sufficiently high to cover the fixed and variable costs of new plant. The model's calculation of SRMC will correctly take into account a range of electricity system features. These include the varying utilisation factors of plant which are influenced by

- Changes in the system generation technology mix over the lifetime of the plant
- Seasonal variability of loads and hydro generation
- Variable inflow levels with hydrological conditions.

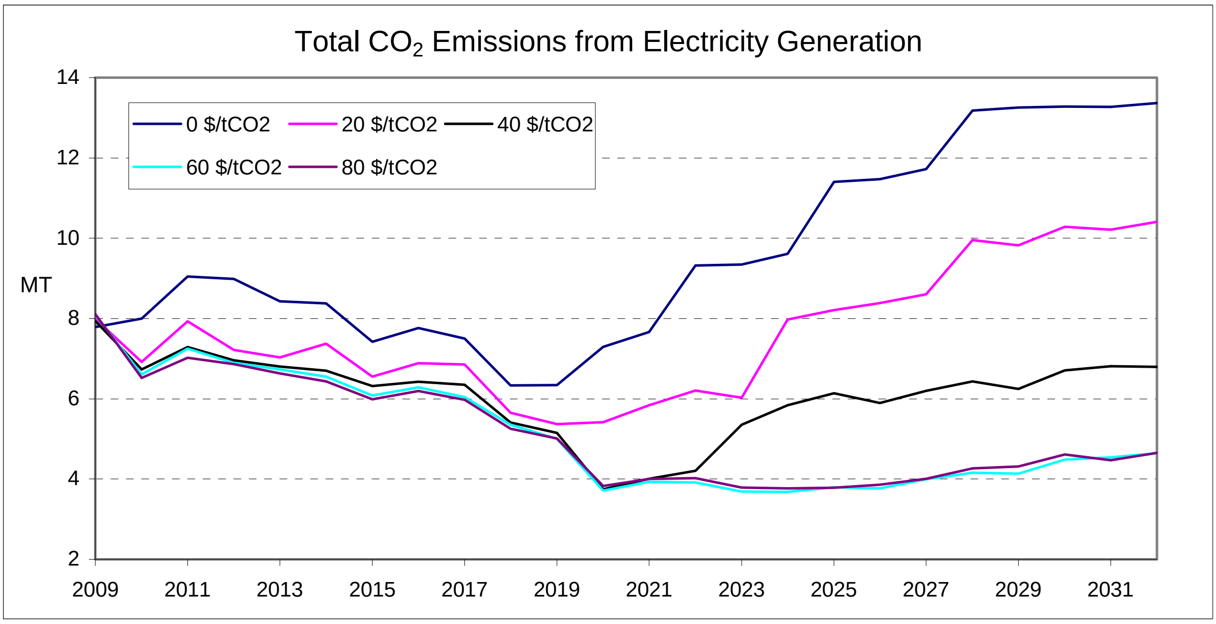

Figure 1: Total CO_2 Emissions per Year

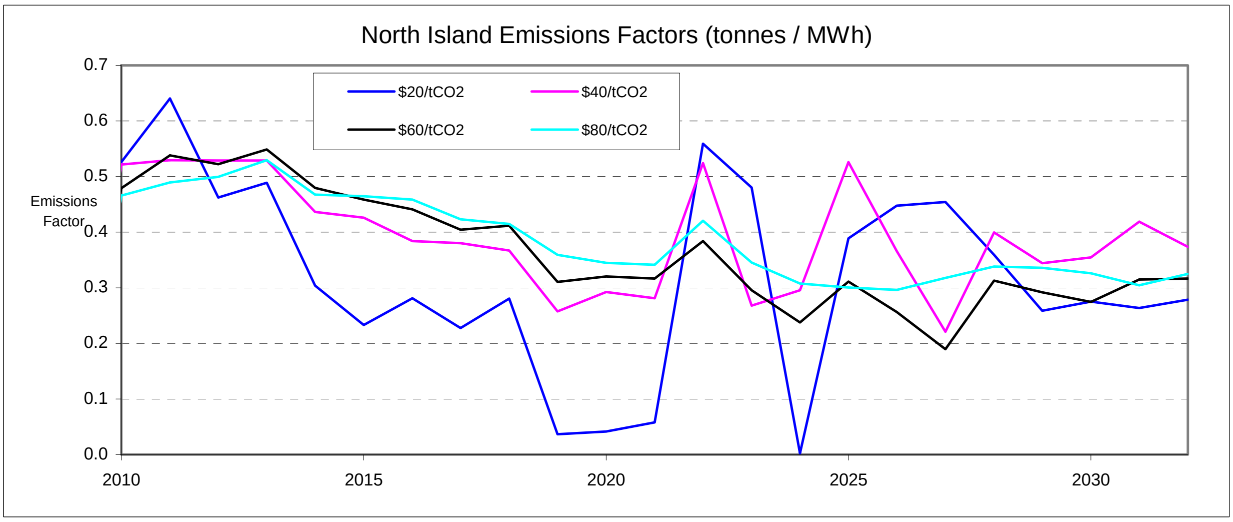

Figure 2: Annual Average Emissions Factor for each carbon cost, for North Island SRMC

Note regarding "Emissions Factor", as shown in Figure 2
The annual average emissions factors reported in Figure 2 are calculated from estimates of increased electricity costs from the SDDP model divided by the appropriate emission price to produce a notional emission factor. This annual average emission factor is an average of monthly estimates from SDDP. Essentially it represents a marginal electricity cost impact. It is not equivalent to the average emissions per unit of electricity sometimes called the average electricity factor which is reported by the Ministry of Economic Development.

Table 1: North Island Emissions Factors (t/MWh)				
$/tCO$_2$	20	40	60	80
2010	0.53	0.52	0.48	0.47
2011	0.64	0.53	0.54	0.49
2012	0.46	0.53	0.52	0.50
2013	0.49	0.53	0.55	0.53
2014	0.30	0.44	0.48	0.47
2015	0.23	0.43	0.46	0.46
2016	0.28	0.38	0.44	0.46
2017	0.23	0.38	0.40	0.42
2018	0.28	0.37	0.41	0.42
2019	0.04	0.26	0.31	0.36
2020	0.04	0.29	0.32	0.34
2021	0.06	0.28	0.32	0.34
2022	0.56	0.52	0.38	0.42
2023	0.48	0.27	0.30	0.35
2024	0.00	0.30	0.24	0.31
2025	0.39	0.53	0.31	0.30
2026	0.45	0.37	0.26	0.30
2027	0.45	0.22	0.19	0.32
2028	0.36	0.40	0.31	0.34
2029	0.26	0.34	0.29	0.34
2030	0.28	0.35	0.27	0.33
2031	0.26	0.42	0.32	0.30
2032	0.28	0.37	0.32	0.32

Study Objective

The objective of this study is to obtain detailed information regarding electricity system performance for a number of scenarios of CO_2 costs. The most important information required is emissions factors, defined as

$$\text{Emissions Factor} = \frac{\text{SRMC with carbon cost - SRMC without carbon cost}}{\text{Carbon cost}}$$

where SRMC = Short Run Marginal Cost

In addition to CO_2 emissions and the effects on SRMC, the extent to which emissions costs pass through into SRMC are studied.

Modelling Approach

The SDDP model was used to simulate system operations over the period 1 January 2009 through to 31 December 2032. Commissioning dates for new plants were calculated using the Electricity Commission's GEM model, and so became an input to SDDP.

Data for SDDP has been obtained from the GEM model's database and from the hydro system inflow data files prepared by Opus Consultants and published by the Electricity Commission. GEM models runs were carried out by the Ministry of Economic Development. Some additional assumptions were provided by the Ministry.

SDDP provides more detailed system information than GEM is able to as it uses a monthly time step, with five load categories per month, and models each hydro storage reservoir explicitly. GEM is a higher level model, and so uses a more approximate system model than SDDP. For example, GEM uses a predetermined pattern for the outputs of hydro plants, rather than a schedule determined specifically for a particular situation. These predetermined patterns appear to have been obtained from an SDDP study. Scenarios with large amounts of renewable generation which can not be scheduled will present different requirements to a scenario with larger amounts of thermal generation. In the former case, existing hydro plants would be required to carry out more load following than in the latter case.

A stochastic optimal dispatch is calculated by SDDP, i.e. dispatch decisions are made without foresight of future inflows. Hence the model has available the same information as generation companies have when making dispatch decisions. SDDP calculates a least cost dispatch, so it does not attempt to represent marketing strategies. A risk neutral optimum is found, so SDDP does not take into account the desire of some market participants to reduce the volatility of their earnings. Typically, market participants would be willing to give up some expected returns to obtain a reduction in volatility. This results in SDDP being more likely to completely empty a particular reservoir when the model can obtain energy from other sources.

SDDP is considered to be a suitable stochastic hydro-thermal dispatch model for this for this particular. Factors influencing this decision include:

1. SDDP is a commercially developed and maintained model, available for purchase or lease by any interested party.
2. SDDP is a mathematical optimisation defined by a set of linear equations. These are described in detail in the software documentation.

3. A data base for SDDP is published by the Electricity Commission, giving a freely available set of data.
4. SDDP is a multi reservoir optimisation, representing each large hydro reservoir and power station separately. All hydro system flow paths are represented correctly, including for example, the spill path from Lake Tekapo down to Benmore (bypassing a number of stations)..

The GEM generation commissioning program can be readily converted into the format required by SDDP. Transpower have made available their software for this study to carry out this conversion.

Scenarios Analysed

Generation Commissioning Programs

Table 2 shows the five commissioning programs studied. Negative MW capacity values indicate a decommissioning, as occurs for the Huntly coal units.

All five scenarios have the Huntly coal units moving to reserve shutdown status with the four units moving to this status in 2013, 2015, 2018 and 2020. All scenarios also have these units finally decommissioning in 2026, 2028, 2030 and 2032. These dates are set as fixed in the GEM optimisation model database, i.e. the model is not free to change these dates.

In all scenarios, it has been assumed that the HVDC link will be upgraded to 1200 MW capacity on 1 January 2012, and to 1400 MW on 1 January 2018.

While clear trends are evident as CO_2 price increases, some apparent inconsistencies occur due to large discrete blocks of investment in generation plant. An additional influence is the nature of the solution process. GEM is solving a very difficult mixed integer optimisation problem, but does not usually solve to completion – the true optimal solution is not found, but rather one that is considered to be "good enough". The solution of a mixed integer problem involves a large amount of trial and error searching, testing different combinations of commissioning dates. While the algorithm attempts to make good choices for the search region, it is not able to test all possible candidates within a reasonable time, so the solution process needs to be terminated at some arbitrary point. This may result in some minor random variability between scenarios.

Table 2: Commissioning Programs

	$0/tCO_2		$20/tCO_2		$40/tCO_2		$60/tCO_2		$80/tCO_2	
		MW		MW		MW		MW		MW
2010	Gas Peaker 1	200	Gas Peaker 1	200	Gas Peaker 1	200	Gas Peaker 1	200	Gas Peaker 1	200
	Rotokawa 2	130	Rotokawa 2	130	Rotokawa 2	130	Rotokawa 2	130	Rotokawa 2	130
	Tahara	20	Tahara	20	Tahara	20	Tahara	20	Tahara	20
									Hawea Gate	17
2011					Mokai 3	17	Hawea Gate	17	Mokai 3	17
					Te Mihi	220	Mokai 3	17	Te Mihi	220
							Te Mihi	220		
2012	Mokai 3	17	Mokai 3	17	Gas Peaker 2	200	Gas Peaker 2	200	Gas Peaker 2	200
	Te Mihi	220	Te Mihi	220	Tauhara 2	200	Tauhara 2	200	Tauhara 2	200
	Hawea Gate	17	Gas Peaker 2	200	Mokai 4	40	Mokai 4	40	Mokai 4	40
	GOCGTS1	150	Tauhara 2	200	Hawea Gate	17				
			Mokai 4	40						
2013	Mohaka	44	Mohaka	44	Mohaka	44	Mohaka	44	Huntly Coal	-226
	Huntly Coal	-226	Huntly Coal	-226	Huntly Coal	-226	Huntly Coal	-226	Huntly RS	245
	Huntly RS	245	Huntly RS		Huntly RS	245	Huntly RS	245		
	Rodney	240								
	Mokai 4	40								
2014			OtoiWaiau	16.5	Otoi Waiau	16.5	Otoi Waiau	16.5	Kakapotahi	17
					Tarawera LO	14	Tarawera LO	14		
					Kakapotahi	17	Kakapotahi	17		
2015	Otoi Waiau	16.5	Huntly Coal	-226	Huntly Coal	-226	Huntly Coal	-226	Huntly Coal	-226
	Huntly Coal	-226	Huntly RS	245	Huntly RS	245	Huntly RS	245	Huntly RS	245
	Huntly RS	245	Mangawhero	60	Mangawhero	60	Mangawhero	60	Lower CR	35
	Tauhara 2	200			Lower CR	35	Motorimu	80	Toaroha	25
	Kakapotahi	17			Toaroha	25	Lower CR	35	Clarence	70
	Toaroha	25			Clarence	70	Toaroha	25		
							Clarence	70		
2016			Kawerau 2	67	Kawerau 2	67	Kawerau 2	67	Kawerau 2	67
			Rotokawa 3	67	Rotokawa 3	67	Rotokawa 3	67	Rotokawa 3	67
2017	Kawerau 2	67	Motorimu	80	Motorimu	80	Turitea	150	Motorimu	80
					Ngatamariki	67	Ngatamariki	67	Ngatamariki	67
2018	Huntly Coal	-226	Huntly Coal	-226	Huntly Coal	-226	Huntly Coal	-226	Huntly Coal	-226
	Huntly RS	245	Huntly RS	245	Huntly RS	245	Huntly RS	245	Huntly RS	245
	Rotokawa 3	67	Long Gully	70	Long Gully	70	Long Gully	70	Long Gully	70
	Ngatamariki	67	Turitea	150	Turitea	150	Queensberry	180	Turitea	150
	Motorimu	80			Queensberry	180			Queensberry	180
	Queensberry	180								

	$\$0/tCO_2$		$\$20/tCO_2$		$\$40/tCO_2$		$\$60/tCO_2$		$\$80/tCO_2$	
		MW		MW		MW		MW		MW
2019	Mangawhero Huntly Gas Arawhata Clarence	60 -66 62 70	Huntly Gas Puketiro L Mahinerangi	-66 120 200	Huntly Gas Puketiro L Mahinerangi Luggate	-66 120 200 90	Huntly Gas Pouto Puketiro L Mahinerangi Luggate	-66 300 120 200 90	Huntly Gas Puketiro L Mahinerangi Arahura Luggate	-66 120 200 62 90
2020	Huntly Coal Huntly RS Lignite 1	-226 245 400	Huntly Coal Huntly RS Marsden C	-226 245 320	Huntly Coal Huntly RS Geothermal 2 Poutu Beaumont	-226 245 110 300 190	Huntly Coal Huntly RS Belmont Beaumont	-226 245 80 190	Huntly Coal Huntly RS Geothermal 2 Beaumont	-226 245 110 190
2021	GOCGTN1	150					Geothermal 2	110	Pouto	300
2022	Marsden C	320					Ohariu Rototun	70 250	Belmont	80
2023					Marsden C Whakapapa	320 16	Mokaira GWind WR1	16 100	Ohariu Rototun	70 250
2024			GCoal1G	400			Waverley Red Hill Top Energy Wainui H Arawhata	100 20 10 30 62	GWind WR1	100
2025	GCoal1G	400	WCC Seam	50	WCC Seam	50	WCC Seam GOCGTN1	50 150	WCC Seam Geothermal 1 Geothermal 3	50 75 110
2026	Huntly RS	-245	Huntly RS	-245	Huntly RS Geothermal 1 Geothermal 3	-245 75 110	Huntly RS Geothermal 1 Geothermal 3	-245 75 110	Huntly RS GOCGTN1 Mokaira	-245 150 16
2027			Geothermal 1	75	Otahuhu C	407	Otahuhu C	407	Gas Peaker 4	200
2028	Huntly RS GCoal4T	-245 300	Huntly RS GCoal4T	-245 300	Huntly RS	-245	Huntly RS	-245	Huntly RS Otahuhu C	-245 407
2029			Geothermal 3	110	Belmont Hayes 1	80 150	HB Wind Hayes 1	2215 0		

	$0/t$CO_2$		$20/t$CO_2$		$40/t$CO_2$		$60/t$CO_2$		$80/t$CO_2$	
		MW		MW		MW		MW		MW
2030	Huntly RS Geothermal 1 Geothermal 2	-245 75 110	Huntly RS Geothermal 2 Glen Exp Gas Peaker 3	-245 110 80 200	Huntly RS Glen Exp Gas Peaker 3	-245 80 200	Huntly RS Glen Exp Gas Peaker 3	-245 80 200	Huntly RS Waverley Top Energy Glen Exp	-245 100 10 80
2031	Geothermal 3	110							HB Wind Red Hill Wainui H Gwave1 Gwave2 Gwave3 Arawhata Nevis River	225 20 30 50 50 50 62 45
2032	Huntly RS Gas Peaker 5	-245 200	Huntly RS Gas Peaker 4	-245 200	Huntly RS Ohariu Rototun Gas Peaker 4	-245 70 250 200	Huntly RS Gwind Wr2 GWave1 Gas Peaker 4 L Hayes 2	-245 100 50 200 160	Huntly RS Gas Peaker 3	-245 200

Fuel Costs and Emissions

All fuel cost data has been obtained from the GEM input data spreadsheet. Carbon emission costs are added to fuel costs for the analysis of the SDDP model.

Fuel prices vary over time only for gas, which increases in a number of steps from $6/GJ in 2009 up to $11/GJ in 2024 (excluding CO_2 costs), and then remains constant, as in Table 5. While geothermal plants have no fuel cost, they have significant CO_2 emissions. The cost of these emissions is treated as a fuel cost, in the same way as it is for other thermal plants.

Table 3: Fuel Costs and CO_2 Adders - Constant over Planning Period

	t CO_2/PJ	Fuel Cost $/GJ	CO_2 Adders ($/GJ), for each CO_2 cost scenario				
			$0/t	$20/t	$40/t	$60/t	$80/t
Coal	91200	4	0	1.824	3.648	5.472	7.296
Diesel	73000	25	0	1.46	2.92	4.38	5.84
Gas	-	-	0	1.056	2.112	3.168	4.224
Lignite	95200	1.8	0	1.904	3.808	5.712	7.616

Table 4: Geothermal CO_2 Adders - Constant over Planning Period

	t CO_2/GWh	Fuel Cost $/MWh	CO_2 Adders ($/MWh), for CO_2 cost scenario				
			$0/t	$20/t	$40/t	$60/t	$80/t
Geothermal	100	0	0	2	4	6	8

Table 5: Gas Price ($/GJ), Including CO_2 Adder

Scenario:	$0/t	$20/t	$40/t	$60/t	$80/t
2009	6	6	6	6	6
2010	6.5	7.556	8.612	9.668	10.724
2011	6.5	7.556	8.612	9.668	10.724
2012	7	8.056	9.112	10.168	11.224
2013	7	8.056	9.112	10.168	11.224
2014	8	9.056	10.112	11.168	12.224
2015	8	9.056	10.112	11.168	12.224
2016	8	9.056	10.112	11.168	12.224
2017	9	10.056	11.112	12.168	13.224
2018	9	10.056	11.112	12.168	13.224
2019	9	10.056	11.112	12.168	13.224
2020	10	11.056	12.112	13.168	14.224
2021	10	11.056	12.112	13.168	14.224
2022	10.5	11.556	12.612	13.668	14.724
2023	10.5	11.556	12.612	13.668	14.724
2024	11	12.056	13.112	14.168	15.224
2025	11	12.056	13.112	14.168	15.224
2026	11	12.056	13.112	14.168	15.224
2027	11	12.056	13.112	14.168	15.224
2028	11	12.056	13.112	14.168	15.224
2029	11	12.056	13.112	14.168	15.224
2030	11	12.056	13.112	14.168	15.224

Electricity Demand

As the AC transmission grid has not been modelled in SDDP, data is required only for total load in each island. This is equivalent to making the assumption that the AC grid will be upgraded sufficiently to avoid all significant constraints. Constraints that exist for short periods, such as during maintenance outages or unexpected failures, need not be considered as they will have a very small impact on overall system operations. The HVDC link is modelled in detail as both constraints and transmission losses on the link have a significant impact on generation requirements.

AC system losses are handled by means of adders to the load in each island. South Island load is increased by 5.34% and North Island load by 3.68% to represent losses. Losses on the HVDC link are calculated within the model which represents these by means of a ten step function. Distribution system losses are effectively embedded in the data, as the load forecasts are for high voltage grid exit point loads.

No price elasticity of demand is modelled. Elasticity effects due to the higher prices caused by carbon costs and variations in cost due to hydro conditions are ignored – demand is a fixed input. Load curtailment is modelled only when short run marginal cost (SRMC) exceeds $500 / MWh.

As can be seen from the load duration curves in Figure 4 and Figure 5, no significant changes in load shape are assumed. SDDP represents load in five categories. The first category represents the peak periods within that month, and contains 7.14% of the hours within the month. The next category, represents a set of lower demand hours within that month and contains 21.43% of the hours within the month. Successive categories (load blocks) represent lower demand periods, and consist of 32.14%, 28.57% and 10.72% of the hours within that month. The final category containing 10.72% of the month represents the lowest demand hours.

Table 6: Annual Load Growth by Island (%)		
	North Island	South Island
2010	2.33	1.90
2011	1.92	1.47
2012	1.74	1.17
2013	1.80	1.11
2014	1.93	0.98
2015	1.98	0.84
2016	1.89	0.61
2017	1.88	0.51
2018	1.88	0.52
2019	1.84	0.55
2020	1.80	0.60
2021	1.60	0.54
2022	1.52	0.53
2023	1.49	0.58
2024	1.48	0.60
2025	1.47	0.61
2026	1.41	0.62
2027	1.39	0.61
2028	1.37	0.63
2029	1.36	0.64
2030	1.36	0.63
2031	1.38	0.65
2032	1.38	0.66

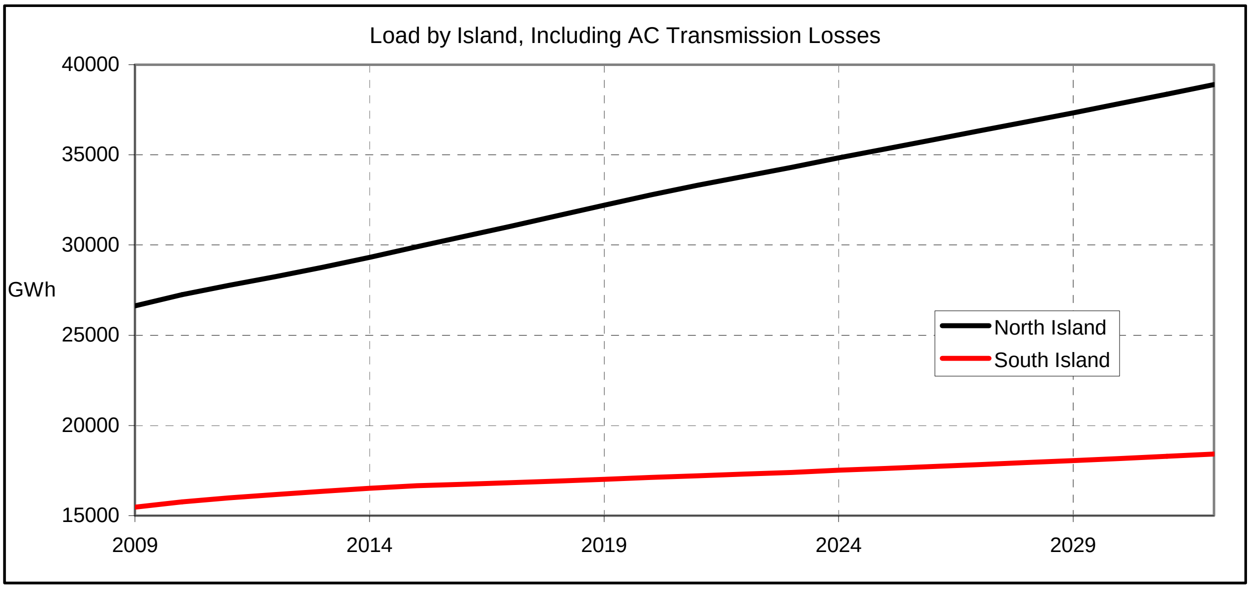

Figure 3: Total Annual Load by Island, including AC transmission system losses, but excluding DC link losses

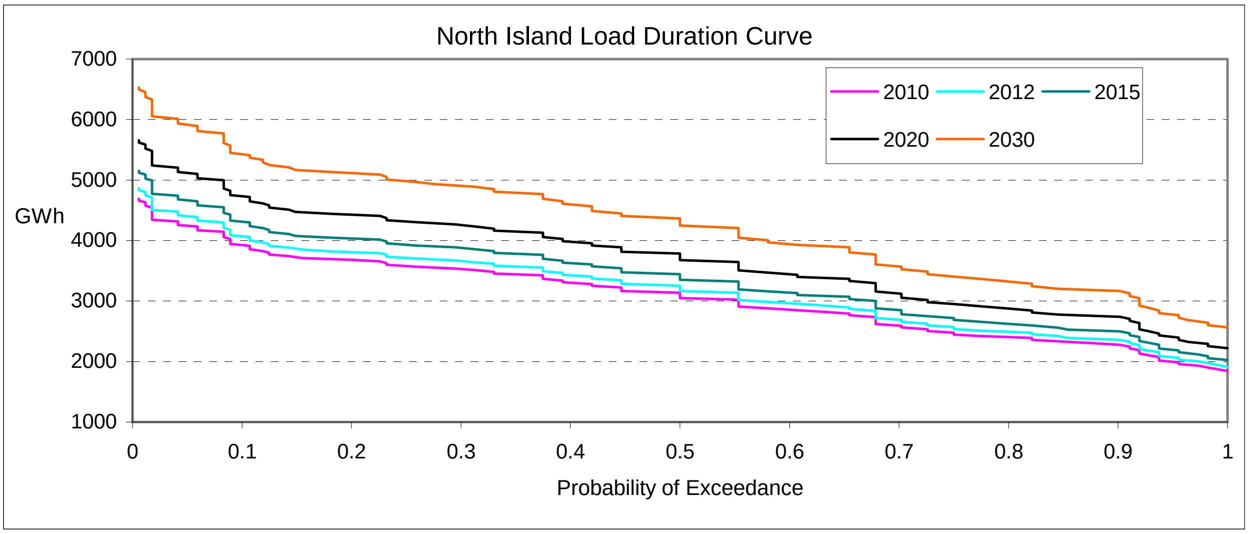

Figure 4: North Island annual load duration curves

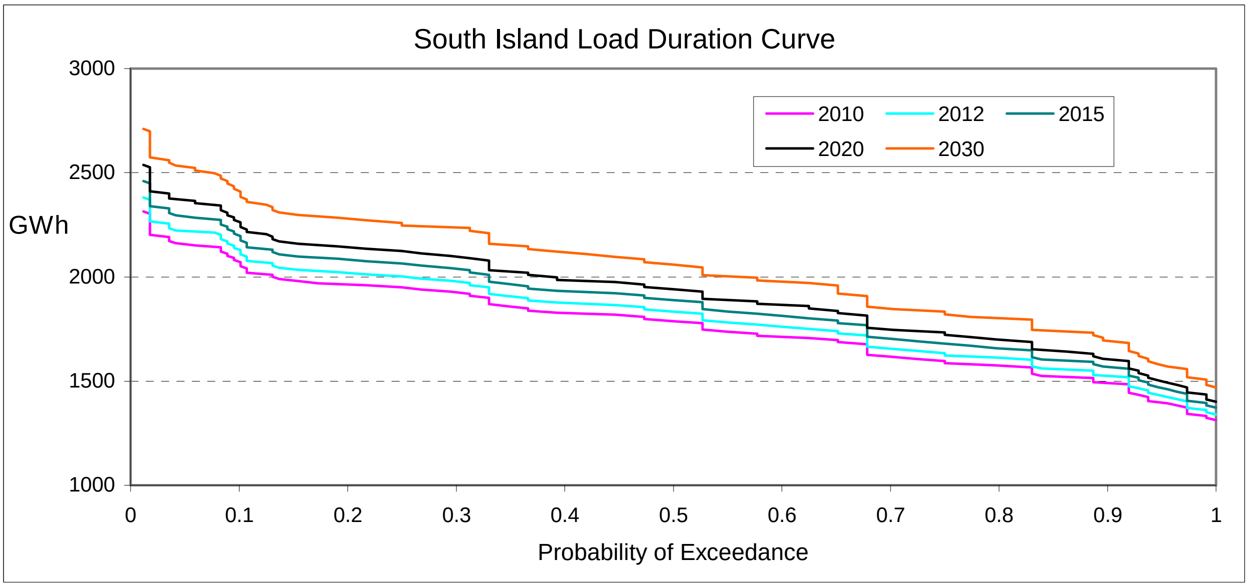

Figure 5: South Island annual load duration curves

Thermal Plant Minimum Running

Minimum running values have been specified for a number of existing thermal plants to represent take or pay fuel contracts. These constraints are important in that the assumption has been made that the flexibility of fuel supplies is limited, and that the same minimum running constraints apply across all carbon cost scenarios.

The following minimum values have been specified (MW):

E3p	154
Otahuhu B	146
Huntly units on Coal	100
Huntly units on reserve	0

An assumption has been made that the existing Taranaki Combined Cycle plant will not have any significant minimum running requirements due to the proximity of the Tariki gas storage facility. No minimum running has been assumed for any of the new coal or gas fired plants.

As the Huntly coal units move to reserve shutdown status, the 100 MW minimum output no longer applies to the unit in reserve. Huntly units are assumed to switch to reserve shutdown status on 1 January in 2012, 2015, 2018 and 2020 – this assumption fixed prior to running the GEM optimal generation planning model. Consequently the total station minimum running constraint reduces by 100 MW in each of these years. The reserve units have an additional variable operating and maintenance cost of $10 per GJ, or $105 per MWh. This represents the additional cost of fuel flexibility and the costs associated with low plant utilisation.

Simulation Results

CO_2 Emissions

Total CO_2 emissions fall with increasing carbon price, as shown in Figure 6, but it is not until around 2018 that the four scenarios with non-zero carbon costs begin to diverge significantly. Figure 7 illustrates a major factor in the divergence in total emissions. The 0, 20, and 40 $/tonne CO_2 scenarios have successively less coal fired capacity added from 2020, and consequently have reducing CO_2 emissions. The 60 and 80 $/tonne CO_2 scenarios have no new coal plants. Note that the Huntly coal decommissioning schedule is common to all scenarios, and so has no effect on this comparison.

Table 7: Total Annual Average CO_2 Emissions (Mt)

	0 $/tCo2	20 $/tCo2	40 $/tCo2	60 $/tCo2	80 $/tCo2
2009	7.79	7.99	7.94	8.09	8.11
2010	8.00	6.92	6.73	6.60	6.52
2011	9.05	7.93	7.28	7.25	7.02
2012	8.98	7.22	6.96	6.90	6.87
2013	8.43	7.03	6.80	6.73	6.63
2014	8.37	7.37	6.70	6.55	6.43
2015	7.42	6.55	6.32	6.08	5.99
2016	7.76	6.89	6.42	6.29	6.19
2017	7.50	6.86	6.35	6.04	5.97
2018	6.33	5.65	5.41	5.35	5.26
2019	6.35	5.38	5.15	5.01	5.01
2020	7.30	5.42	3.74	3.71	3.83
2021	7.66	5.84	4.01	3.93	4.00
2022	9.32	6.21	4.21	3.92	4.02
2023	9.34	6.03	5.36	3.69	3.79
2024	9.61	7.98	5.84	3.68	3.76
2025	11.40	8.21	6.14	3.80	3.78
2026	11.48	8.38	5.90	3.77	3.86
2027	11.72	8.60	6.20	3.99	4.01
2028	13.18	9.96	6.43	4.16	4.27
2029	13.26	9.82	6.25	4.14	4.31
2030	13.28	10.28	6.71	4.48	4.62
2031	13.27	10.21	6.81	4.55	4.47
2032	13.37	10.41	6.80	4.65	4.66

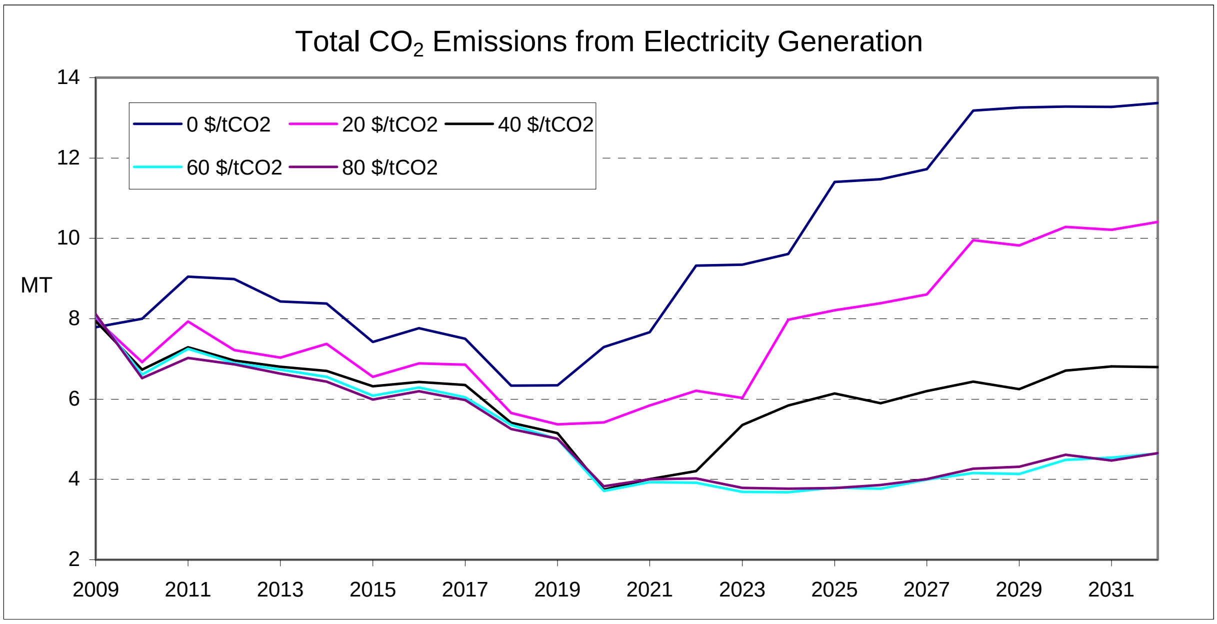

Figure 6: Total CO_2 Emissions per Year

The Otahuhu C gas fired combined cycle plant commissions in 2027 or 2028 for 40, 60 and 80 $/tonne scenarios only. The impact of this plant on total emissions from gas fuel consumption is more modest than that of the coal fired units. Table 8 shows total annual emissions from gas consumption for the five scenarios. None of the existing combined cycle plants are decommissioned during the study period.

Table 8: Emissions from Gas Consumption for Electricity Generation in 2030 (Mt)

$/t CO_2	0	20	40	60	80
CO_2	2.36	2.08	2.71	2.55	2.66

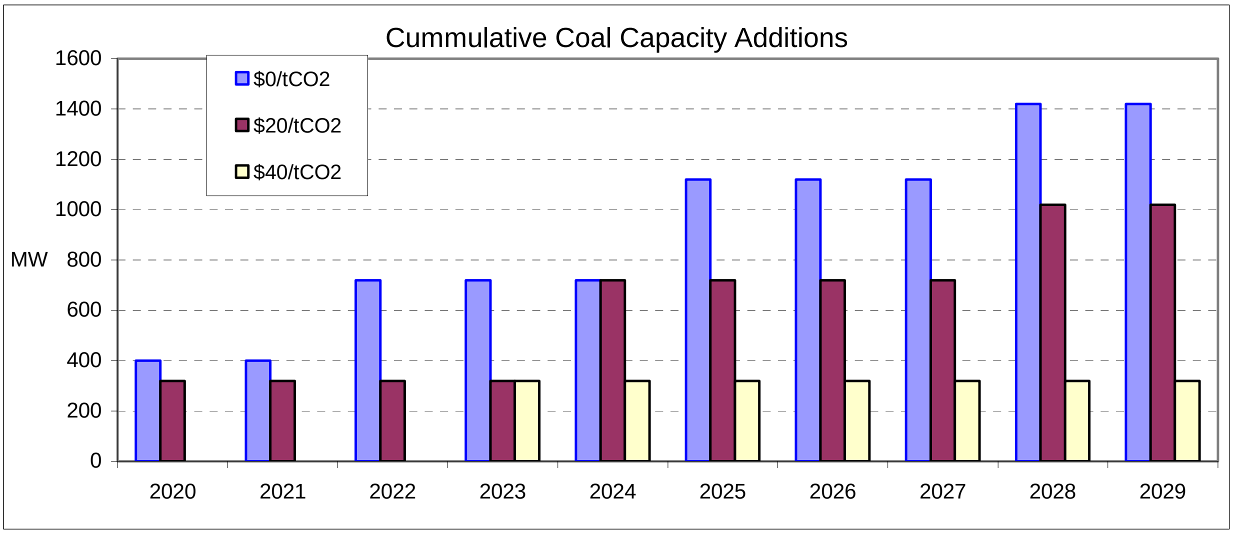

Figure 7: Cumulative New Coal Fired Capacity Added to System (No additions prior to 2020, no coal plant added for 60 and 80 $/t scenarios)

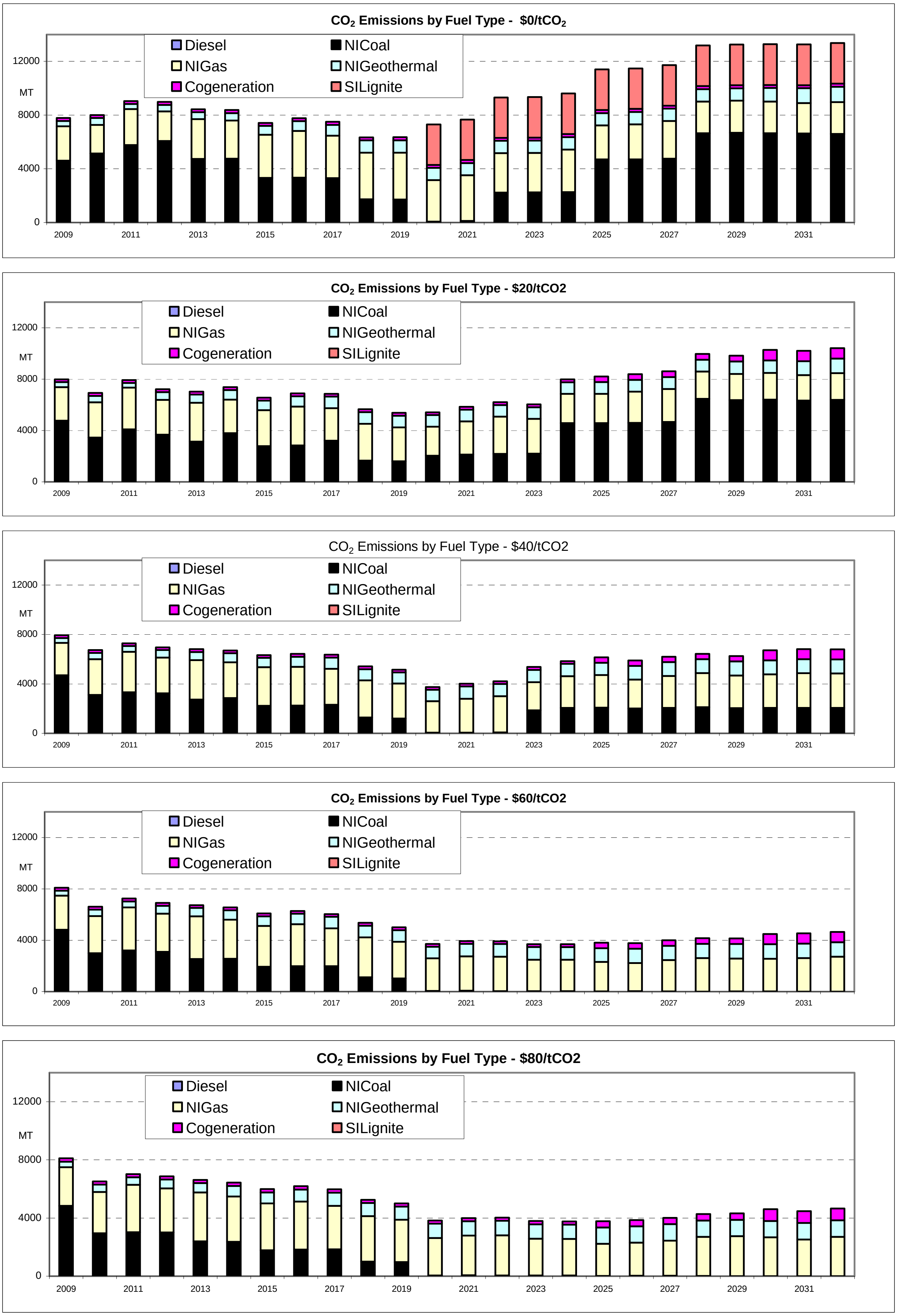

Figure 8: Annual Average CO_2 Emissions by Fuel Type

Short Run Marginal Cost

SRMC increases as expected with carbon charge, and also tracks upward with the increasing cost of gas fired generation over the period until 2024. Average SRMC is generally a little above the cost of gas fired generation (Table 9), suggesting that this plant is frequently marginal.

The relative costs of coal and gas fuels help in comparing the commissioning programs for the various scenarios. For 0, 20 and 40 $/tonne scenarios, coal plant variable costs are significantly lower than for gas plants, from 2020, resulting in the commissioning of varying amounts of new coal plant. For the 60 and 80 $/tonne scenarios, coal plant variable costs are similar to those for gas, resulting in no new coal plants being built, but the Otahuhu C gas fired combined cycle plant is commissioned in both of these higher carbon cost scenarios.

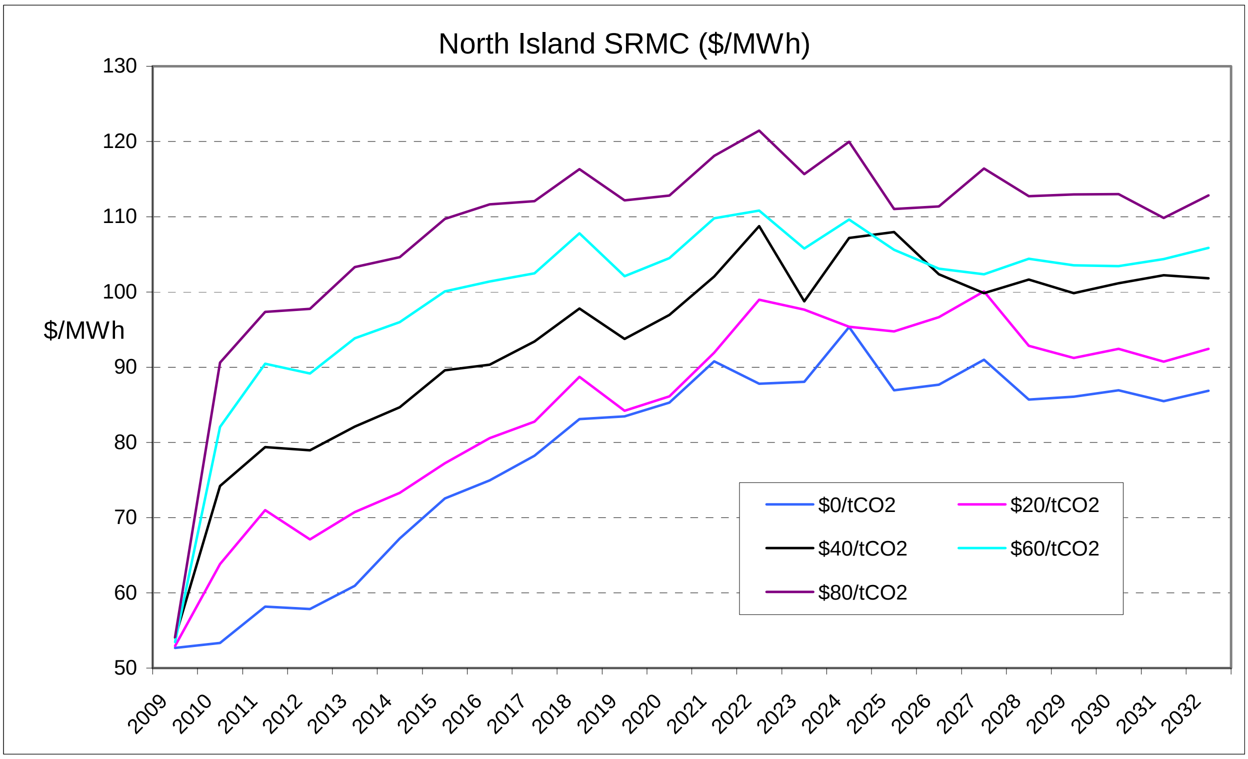

Figure 9: North Island Annual Average SRMC ($/MWh)

Table 9: Cost of Gas Fired Generation Comprising Fuel, Carbon Charge and Variable Operation & Maintenance Cost ($/MWh)					
$/tCO$_2$	0	20	40	60	80
2009	46.8	46.8	46.8	46.8	46.8
2010	50.4	57.8	65.3	72.8	80.3
2012	53.9	61.4	68.9	76.3	83.8
2014	61.0	68.5	75.9	83.4	90.9
2017	68.1	75.5	83.0	90.5	98.0
2020	75.2	82.6	90.1	97.6	105.1
2022	78.7	86.2	93.6	101.1	108.6
2024	82.2	89.7	97.2	104.7	112.1

(Constant costs for gas fired plants apply from 2024)

Table 10: Cost of Coal Fired Generation, Fuel, Carbon Charge and Variable Operation & Maintenance Cost ($/MWh)					
$/tCO$_2$	0	20	40	60	80
	47.0	64.3	81.7	99.0	116.3

Table 11: North Island Annual Average SRMC ($/MWh)					
$/t$CO_2$	0	20	40	60	80
2009	52.7	52.9	54.1	53.5	54.1
2010	53.3	63.9	74.2	82.1	90.6
2011	58.2	71.0	79.4	90.5	97.3
2012	57.8	67.1	79.0	89.2	97.8
2013	60.9	70.7	82.1	93.9	103.3
2014	67.2	73.3	84.7	96.0	104.6
2015	72.6	77.2	89.6	100.1	109.7
2016	75.0	80.6	90.3	101.4	111.7
2017	78.2	82.8	93.4	102.5	112.1
2018	83.1	88.7	97.8	107.8	116.3
2019	83.5	84.2	93.8	102.1	112.2
2020	85.3	86.1	97.0	104.5	112.8
2021	90.8	92.0	102.1	109.8	118.1
2022	87.8	99.0	108.8	110.8	121.4
2023	88.1	97.7	98.8	105.8	115.7
2024	95.3	95.4	107.2	109.6	120.0
2025	87.0	94.7	108.0	105.6	111.0
2026	87.7	96.7	102.3	103.1	111.4
2027	91.0	100.1	99.8	102.4	116.4
2028	85.7	92.9	101.7	104.4	112.7
2029	86.1	91.3	99.8	103.6	113.0
2030	86.9	92.4	101.1	103.4	113.0
2031	85.5	90.8	102.2	104.4	109.9
2032	86.9	92.4	101.8	105.9	112.9

Variability of SRMC within each scenario occurs due to the large discrete investments, and variability between scenarios is also likely to be discontinuous. As carbon charge increases progressively, changes will not necessarily occur smoothly, but in jumps when the relative costs of options change. Some of the effects of this behaviour can be seen in Figure 10 which shows increases in SRMC, relative to the zero cost carbon case. The period 2020 to 2025 is particularly volatile as a number of large coal fired plants are commissioned, as shown in Figure 7.

Prices spike upwards in 2018 with the assumed decommissioning of the last Huntly coal fired unit. A larger upward spike occurs in 2022 in the extra cost of the scenarios with carbon costs, especially the 20 and 40 $/tonne cases, relative to the zero carbon cost scenario. The increase is exacerbated by a fall in the SRMC of the $0/t scenario in the same year. This behaviour is explained by the following observations:

- Marsden C, 320 MW is commissioned in the $0/t case in 2022
- In the 40 $/t scenario Marsden C is commissioned in 2023
- In the 20 $/t scenario a 400 MW coal plant is commissioned in 2024

Hence the $0/t scenario has a fall in SRMC in 2022 when the large Marsden C plant is commissioned. The 20 and 40 $/tonne scenarios have increases in SRMC at this time as no new generation is commissioned in the two years prior to the entry of the large new plants onto the system. In general, a rise in SRMC is to be expected prior to the commissioning of a large base load plant, followed by a significant fall after the plant begins generating. The differences in timing of these plants between scenarios gives rise to the spikes in the differences in costs of the scenarios.

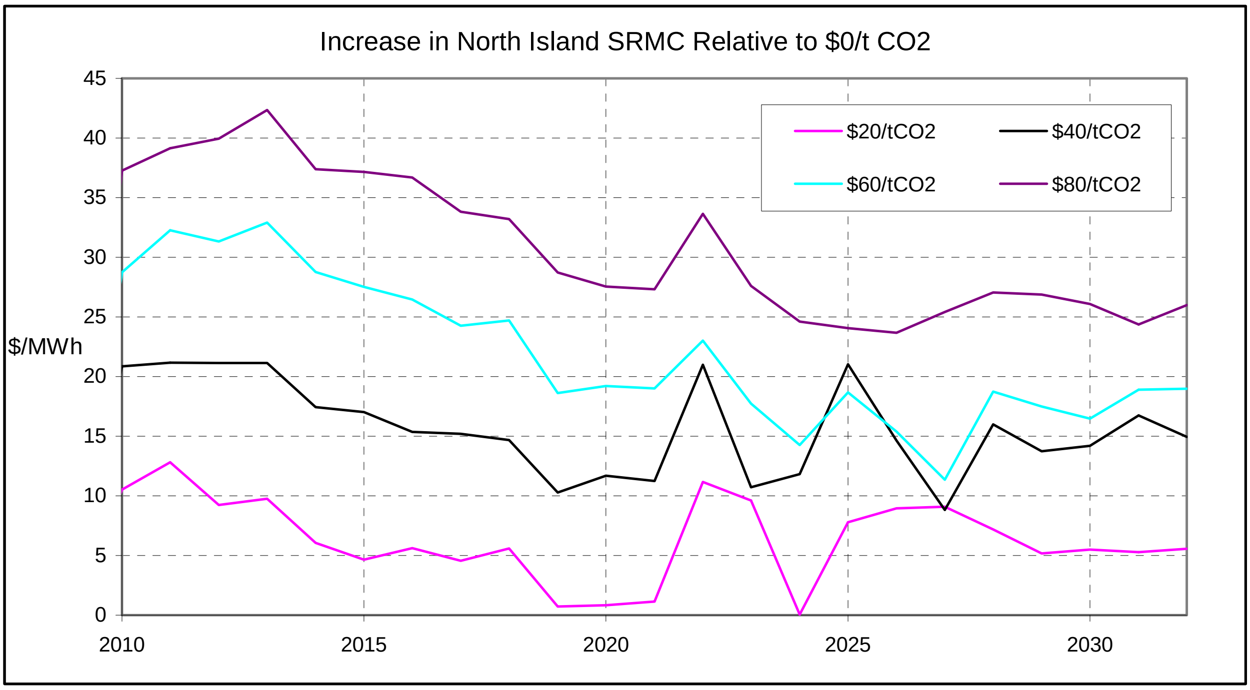

Figure 10: North Island Annual Average Increase in SRMC ($/MWh)

Emissions Factors

An emissions factor has been defined to assist in determining the quantity of emission credits required to compensate an electricity consumer for the price effects of carbon costs on electricity prices. The following definition is used:

$$\text{Emissions Factor} = \frac{\text{SRMC with carbon cost - SRMC without carbon cost}}{\text{Carbon cost}}$$

Figure 11 shows that North Island emissions factors are generally declining, and have similar values for all scenarios except the $20/t CO2 case over a part of the study period. In the previous section, some reasons for SRMC spikes were discussed. As the emissions factor is calculated from the difference between the SRMC of two scenarios, it is particularly susceptible to the factors causing variability in SRMC. The 2018 to 2028 period includes the commissioning (and decommissioning) of large blocks of generation giving raised SRMC prior to commissioning and depressed SRMC afterwards.

A separate set of emissions factors has been calculated for each island, as SRMC is calculated separately for each island. Small differences in SRMC between the islands will exist whenever power is being transferred on the HVDC link, except when the link is at maximum capacity. The small differences are due to transmission losses on the link. Larger differences in SRMC can occur only for the small proportion of time for which the HVDC link is operating at full capacity.

Given the uncertainty in timing of electricity system investments, the smoother results given by five year rolling average values may be more useful. These are shown in Figure 13 for the North Island.

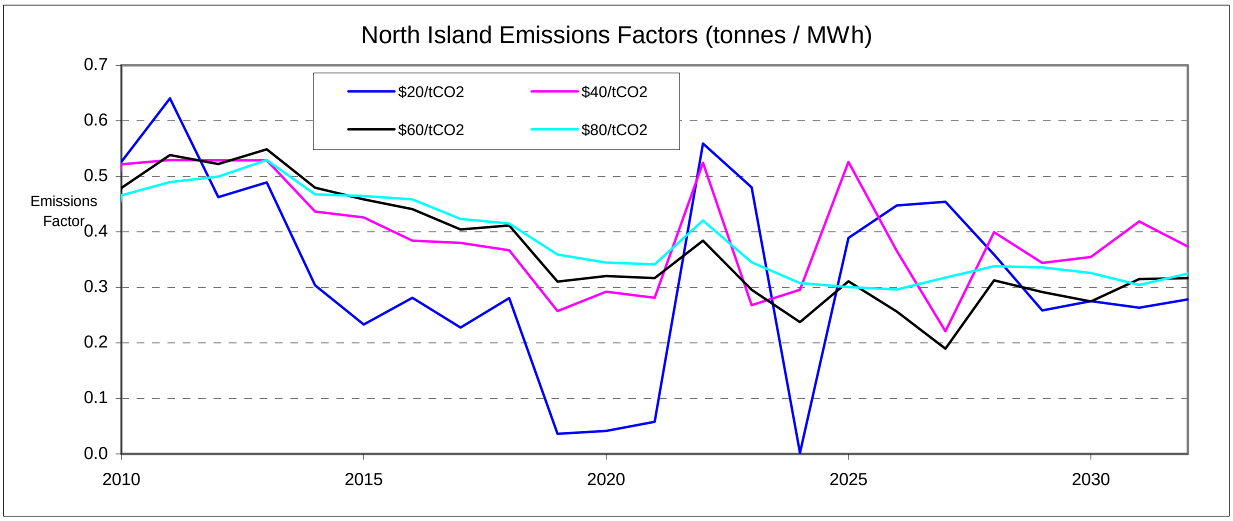

Figure 11: Annual Average Emissions Factor for each carbon cost, North Island SRMC.

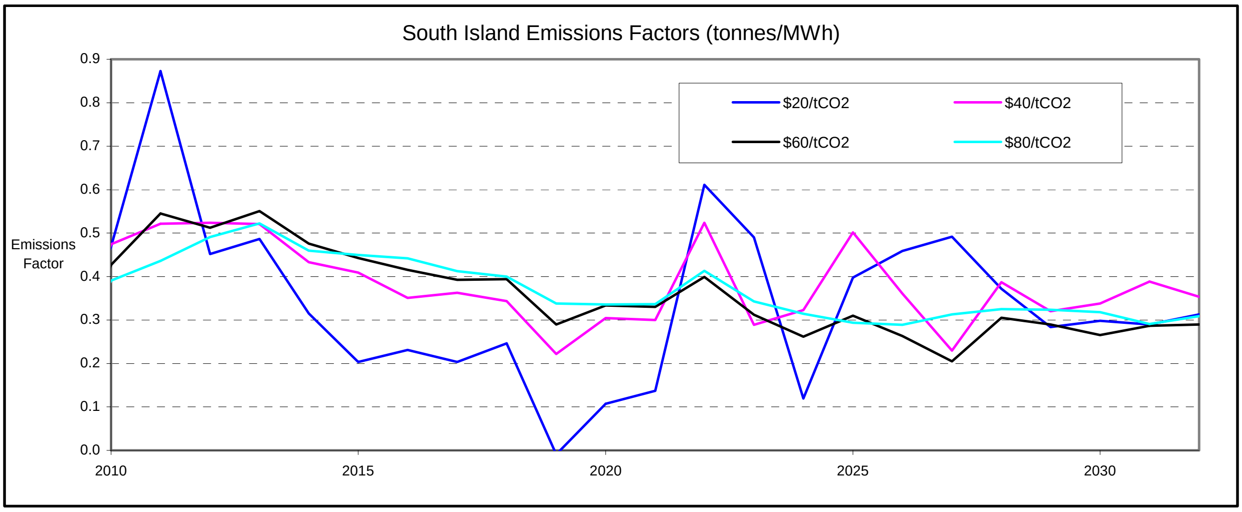

Figure 12: Annual Average Emissions Factor for each carbon cost, South Island SRMC.

Table 12: North Island Emissions Factors (t/MWh)

$\$/tCO_2$	20	40	60	80
2010	0.53	0.52	0.48	0.47
2011	0.64	0.53	0.54	0.49
2012	0.46	0.53	0.52	0.50
2013	0.49	0.53	0.55	0.53
2014	0.30	0.44	0.48	0.47
2015	0.23	0.43	0.46	0.46
2016	0.28	0.38	0.44	0.46
2017	0.23	0.38	0.40	0.42
2018	0.28	0.37	0.41	0.42
2019	0.04	0.26	0.31	0.36
2020	0.04	0.29	0.32	0.34
2021	0.06	0.28	0.32	0.34
2022	0.56	0.52	0.38	0.42
2023	0.48	0.27	0.30	0.35
2024	0.00	0.30	0.24	0.31
2025	0.39	0.53	0.31	0.30
2026	0.45	0.37	0.26	0.30
2027	0.45	0.22	0.19	0.32
2028	0.36	0.40	0.31	0.34
2029	0.26	0.34	0.29	0.34
2030	0.28	0.35	0.27	0.33
2031	0.26	0.42	0.32	0.30
2032	0.28	0.37	0.32	0.32

Table 13: South Island Emissions Factors (t/MWh)				
$/tCO$_2$	20	40	60	80
2010	0.47	0.47	0.43	0.39
2011	0.87	0.52	0.55	0.44
2012	0.45	0.52	0.51	0.49
2013	0.49	0.52	0.55	0.52
2014	0.32	0.43	0.48	0.46
2015	0.20	0.41	0.44	0.45
2016	0.23	0.35	0.42	0.44
2017	0.20	0.36	0.39	0.41
2018	0.25	0.34	0.39	0.40
2019	-0.01	0.22	0.29	0.34
2020	0.11	0.30	0.33	0.34
2021	0.14	0.30	0.33	0.34
2022	0.61	0.52	0.40	0.41
2023	0.49	0.29	0.31	0.34
2024	0.12	0.32	0.26	0.31
2025	0.40	0.50	0.31	0.29
2026	0.46	0.36	0.26	0.29
2027	0.49	0.23	0.20	0.31
2028	0.37	0.39	0.31	0.32
2029	0.28	0.32	0.29	0.32
2030	0.30	0.34	0.27	0.32
2031	0.29	0.39	0.29	0.29
2032	0.31	0.35	0.29	0.31

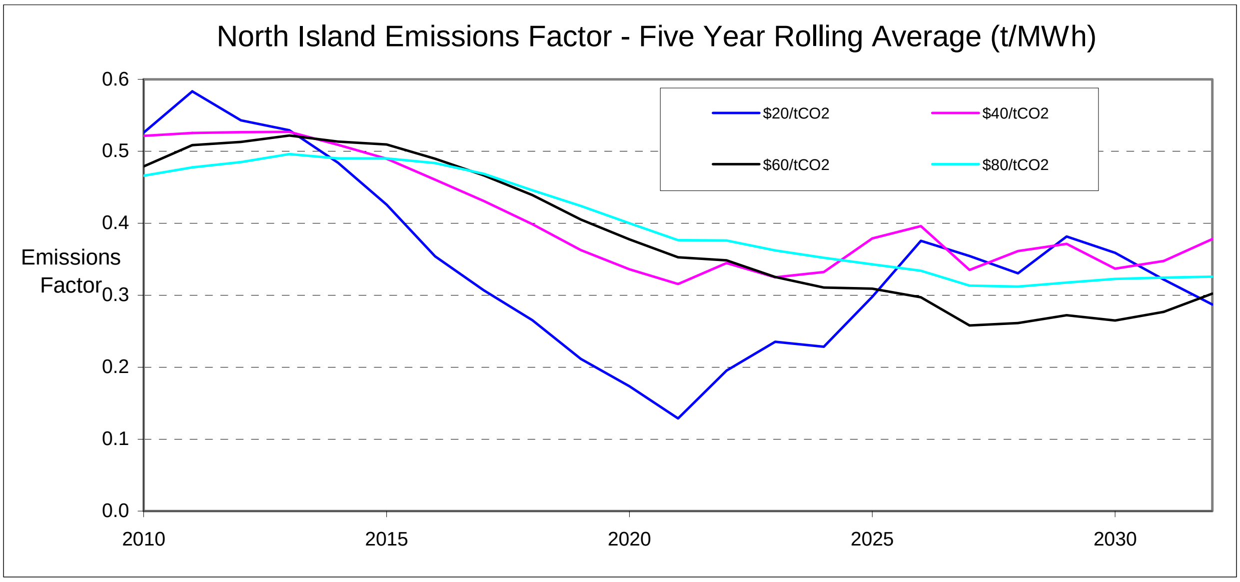

Figure 13: Five Year Rolling Averages of Emissions Factor for each carbon cost, North Island SRMC.

Utilisation of Thermal Plant

An important assumption in the input data to SDDP was that of minimum running of some thermal units. This minimum running is thought necessary to enable the required fuel contracts to be put in place. Figure 14 shows that for all of the scenarios with non zero carbon costs, the Huntly unit studied spends a considerable proportion of its time running at minimum load. This might call into question whether these units can remain viable, especially for carbon costs of \$40/tonne and higher. The gas fired E3p unit does not spend such large amounts of time at minimum.

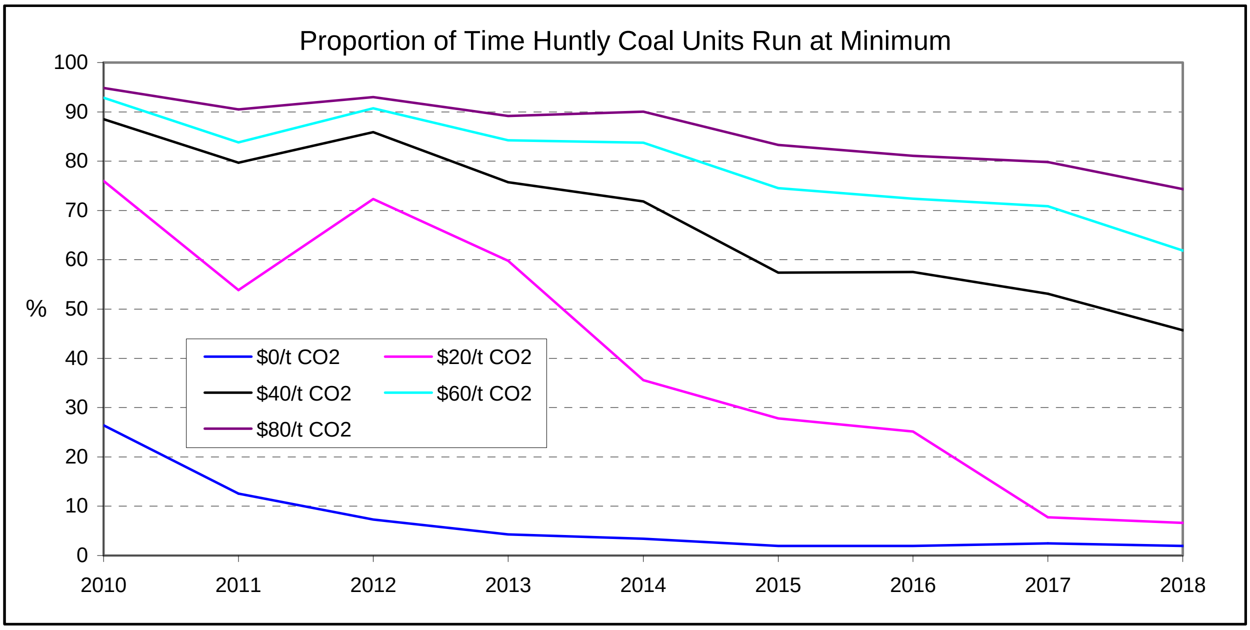

Figure 14: Percentage of Each Year Huntly Coal Unit 4 runs at Minimum

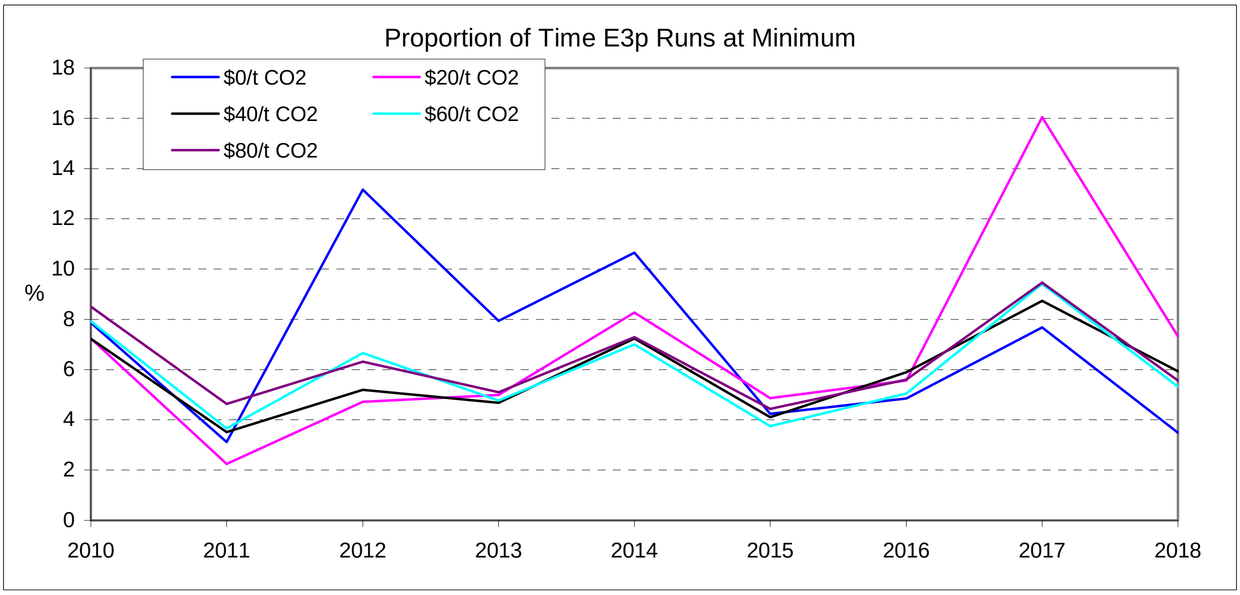

Figure 15: Percentage of Each Year Huntly E3p Combined Cycle Plant Runs at Minimum

Discussion of Results

Interpretation of Model Prices

The SDDP model price results will differ from those actually observed in a number of ways.

1. Actual prices are unlikely to be less than those calculated by SDDP for any significant time. Because SDDP optimises system operation, any other strategy will have a higher expected cost. Hence the lowest cost outcome that the electricity market could deliver will be that calculated by SDDP. Anything else will have higher costs.
2. SDDP is risk neutral – it attempts to minimise the expected cost of system operation with out regard for the variability of costs from one inflow realisation to another. Profit driven market participants are likely to attempt to reduce the variability of their earnings, which will increase the expected cost of system operation and hence is a factor resulting in market prices being above those calculated by SDDP.
3. Marketing strategies will increase prices, in some situations, to enable generation companies to earn sufficient revenue to cover fixed costs, not just variable costs. The extent that offers can be increased is limited by competitive market forces, which depend on a variety of factors, including the ownership of generation plant and the amount of surplus generation capacity available.

Generation companies are required to offer plant at variable cost in some electricity markets. In these markets, a capacity payment is usually made to enable recovery of fixed costs. The ability of generation companies to makes offers at prices above their variable cost is an essential feature of the New Zealand market to ensure the viability of generation companies.

As a result of the above issues it is most unlikely that market prices will for any significant length of time be lower than the SRMC calculated by SDDP.

The least cost basis of the model results in a further important limitation on the conclusions that can be drawn regarding company profitability. If the model indicates that a company will have increased revenues, then it is likely that this will be the case in reality. However, the converse does not hold, i.e. if the model shows a reduction in the profits of a company, this will not necessarily be the case in reality. This is because of the likelihood of marketing strategies allowing successful offers to be made at above the least cost SRMC.

Short Run Marginal Cost

Short run marginal cost (SRMC) is defined as the cost per MWh of the most expensive plant currently generating. In the SDDP model, only variable costs contribute to SRMC, as all fixed costs are ignored – fixed costs do not enter into the dispatch decision making process (because they can not be changed). Any plant operating at minimum output, or which has been defined to be a “must run” plant, can not set the marginal cost. Hydro plants can set the marginal cost, even though their variable operating costs are modelled as being zero. This is because the model determines a shadow price for water. This water value represents the expected future fuel cost savings that this water could provide, if it was to be held back in storage rather than being used in the current period.

The optimisation model GEM has been used to determine the commissioning dates of new plant. This will give consistent results to the extent possible, given that generation investments can only occur in discrete units. New plant will be commissioned only when the annual cost of the capital required by the new plant, plus the variable operating costs of that plant, are less than the alternative of generating more from an existing plant. As load grows, the utilisation of existing plant will rise and shortfall probability will increase. Eventually, the cost of a new plant will be justified.

Consequently, long run marginal cost and short run marginal cost will converge over time. Calculation of an LRMC value requires some assumption for the plant factor of the generator concerned, i.e. how much will it generate each year of its life. For a given plant, a higher plant factor will result in a lower LRMC value. By using the GEM and SDDP models, the appropriate plant factor does not need to be selected a priori – the model will utilise each plant to the extent that is optimal, which will usually vary over the lifetime of the plant. As SRMC is an output of the system model, no such assumption is needed. Therefore the SRMC produced by an optimal dispatch model such as SDDP is likely to give a more consistent results.

GEM also includes a capacity constraint, the value of which is somewhat arbitrary, but necessary to ensure adequate peak capacity is added to the system. The arbitrary nature of this constraint may introduce some distortions, but studies to date suggest that these distortions are small.

Appendix 1: Marginal Emissions

Marginal emissions have been calculated by running a second set of SDDP cases with an additional 240 GWh of base load demand per year in the North Island. To put the marginal emissions shown in Figure 16 into context, Table 14 gives the emissions per MWh for three types of generation. The marginal emissions from the SDDP studies are consistent with gas being the marginal plant much of the time for all cases (i.e. approximately 0.4 tonnes CO_2 /MWh) after 2018. Slightly lower marginal emissions occur for the higher carbon cost scenarios as the probability of coal being marginal decreases, and that of zero emission generation being marginal increases with carbon cost.

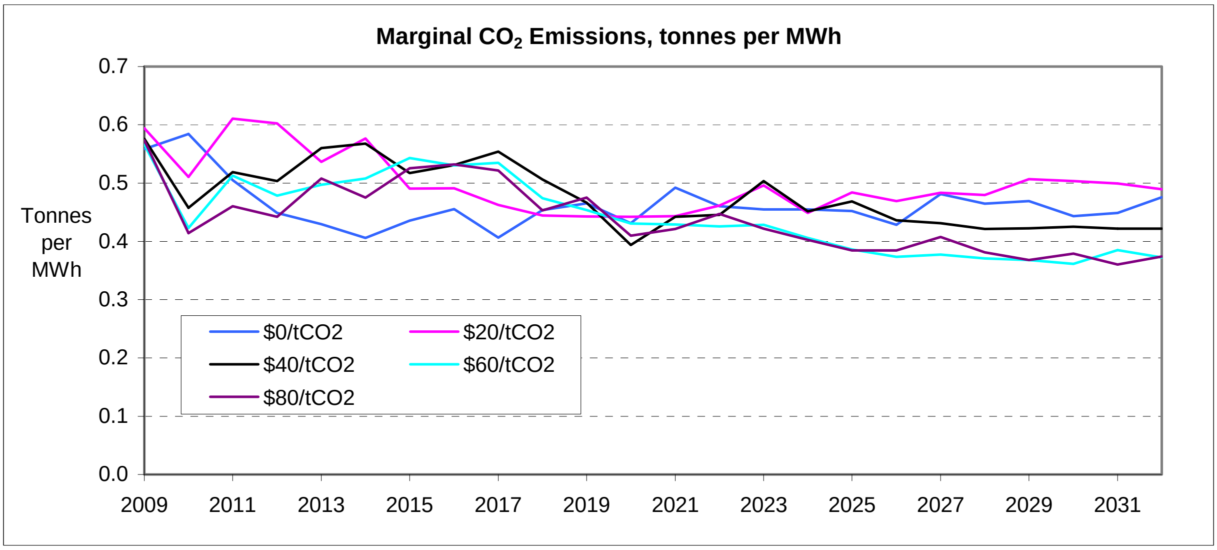

Figure 16: Marginal CO_2 Emissions, for an Increase in Demand of 240 GWh in the North Island Only

Table 14: Emissions per MWh Generation	
	Tonnes CO_2 / MWh
Huntly Coal	0.958
Otahuhu B gas	0.372
Geothermal	0.1

Notes:
Assumed heat rates (MJ/MWh): Huntly Coal 10,500 Otahuhu B 7,050
Carbon content (t CO_2/PJ): 91,200 for coal 52,800 for gas

Table 15 shows the cost of marginal emissions in $/MWh terms. For each scenario, the marginal emissions per MWh have been multiplied by that scenario's carbon cost. These values, along with SRMC, are used to calculate those in Table 16. This latter table deducts from the marginal emissions cost the increase in SRMC above the SRMC of the zero emissions cost case. The result in Table 16 indicates the extent to which marginal emissions costs have been passed through into SRMC.

If the cost difference in Table 16 is positive, some of the marginal emissions cost was not able to be passed through into the SRMC. Conversely, negative values indicate that the SRMC has increased by more than the marginal emissions cost. Clearly, not all the marginal carbon costs have been passed thorough into the SRMC in these studies.

Table 15: Cost of Marginal Emissions ($/MWh)				
$/tCO$_2$:	20	40	60	80
2010	10.2	18.3	25.4	33.1
2011	12.2	20.8	30.8	36.8
2012	12.1	20.1	28.7	35.4
2013	10.7	22.4	29.8	40.6
2014	11.5	22.7	30.5	38.0
2015	9.8	20.7	32.6	42.1
2016	9.8	21.2	31.8	42.6
2017	9.3	22.2	32.1	41.7
2018	8.9	20.2	28.4	36.3
2019	8.9	18.7	27.2	38.0
2020	8.8	15.8	25.9	32.8
2021	8.9	17.7	25.7	33.7
2022	9.2	17.8	25.5	35.8
2023	9.9	20.2	25.7	33.8
2024	9.0	18.1	24.4	32.2
2025	9.7	18.7	23.2	30.8
2026	9.4	17.4	22.4	30.8
2027	9.7	17.3	22.6	32.6
2028	9.6	16.9	22.2	30.5
2029	10.1	16.9	22.1	29.5
2030	10.1	17.0	21.7	30.3
2031	10.0	16.9	23.1	28.9
2032	9.8	16.9	22.3	29.9

Table 16: Difference, Marginal Emission Cost minus Increase in SRMC Above No Emission Cost Scenario ($/MWh)				
$/tCO$_2$:	20	40	60	80
2010	-0.3	-2.6	-3.4	-4.1
2011	-0.6	-0.4	-1.5	-2.3
2012	2.8	-1.0	-2.6	-4.6
2013	1.0	1.2	-3.1	-1.7
2014	5.5	5.3	1.7	0.6
2015	5.1	3.7	5.1	4.9
2016	4.2	5.9	5.4	5.9
2017	4.7	7.0	7.8	7.9
2018	3.3	5.6	3.7	3.0
2019	8.1	8.4	8.6	9.3
2020	8.0	4.1	6.6	5.2
2021	7.7	6.4	6.7	6.4
2022	-2.0	-3.2	2.5	2.1
2023	0.3	9.4	8.0	6.2
2024	8.9	6.2	10.1	7.6
2025	1.9	-2.3	4.5	6.7
2026	0.4	2.8	7.0	7.1
2027	0.6	8.4	11.3	7.2
2028	2.4	0.9	3.5	3.5
2029	5.0	3.1	4.6	2.6
2030	4.6	2.8	5.2	4.2
2031	4.7	0.1	4.2	4.5
2032	4.2	1.9	3.4	3.9

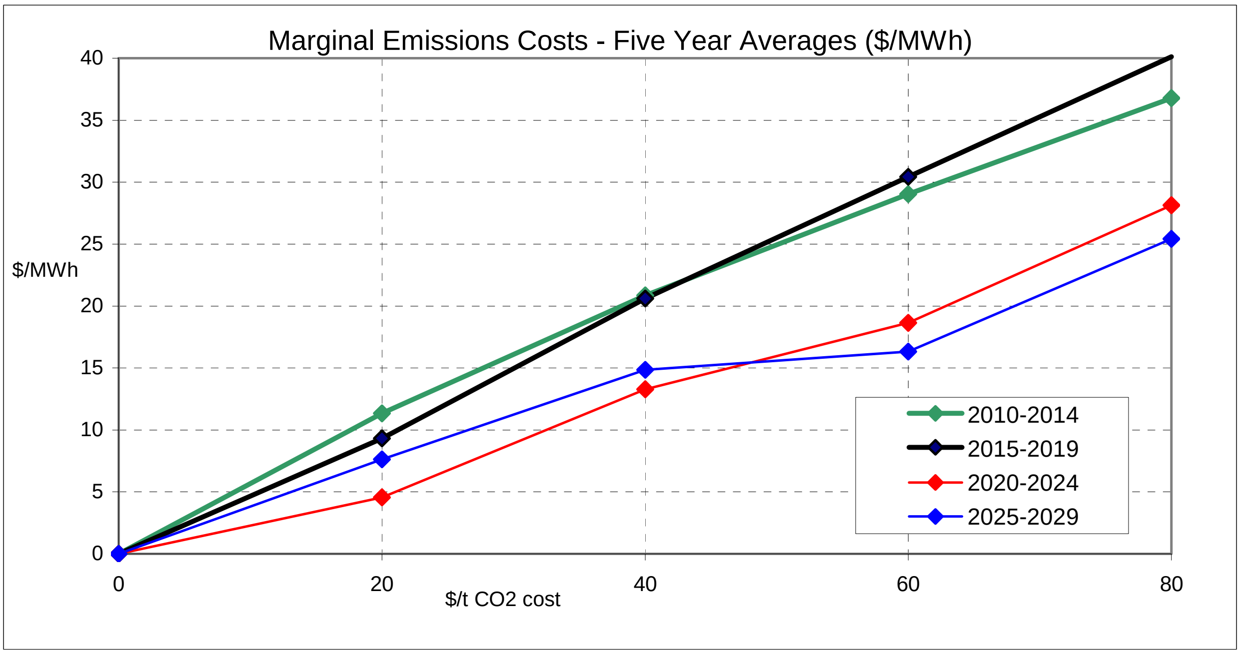

Figure 17: Five Year Average Marginal Emissions Costs ($/MWh)

Appendix 2: SDDP Model Features

To calculate generation dispatch and consequent fuel consumption, carbon dioxide emissions, etc, an optimal generation dispatch model has been used. Dispatch of each plant can only be calculated by modelling it as part of the integrated system, so a complete model of the New Zealand generation system is necessary.

The Stochastic Dual Dynamic Programming model (SDDP) is capable of representing most of the key aspects of the New Zealand system, for a long term study. Important features of the SDDP model include:

- accurate representation of the uncertain nature of hydro system inflows
- stochastic management policy for hydro storage lakes
- treatment of both hydro and thermal plants
- ability to handle retirements of existing plants, and commissioning of new plant
- sufficiently long time horizon (25 years for this study)
- modelling of HVDC link and losses in detail
- representation of annual, seasonal and monthly patterns in load
- optimal dispatch, rather than rule based, to allow consistent treatment of a wide range of system conditions and configurations

The AC transmission system can also be modelled in detail, but this feature was not used for the current study as it would have very little influence on the results.

SDDP is one of the most widely used models throughout the world for hydro-thermal power system planning. This software was developed and is maintained by Power Systems Research Inc, of Rio de Janeiro, Brazil. It is used extensively in Central and South America and has also been used in Scandinavia, Eastern Europe, the Philippines, the US Pacific Northwest, and in New Zealand for several years. The model is designed both for medium term system operations planning and for longer-term development studies. The time increment used for this study was one month, although weekly time steps can be used for shorter term studies.

The objective of the model is to meet a specified system load at the lowest possible overall cost. The prices determined by SDDP will generally represent a lower bound on actual market prices, and the probabilities of shortfall calculated by SDDP are also likely to be a lower bound on those realized in a market situation.

A stochastic optimal dispatch is determined by SDDP. This means that at each stage the model uses only the information that would be available to a real decision maker - it does not have foresight regarding future inflows. Deterministic models, i.e. those with foresight, will show lower probabilities for shortfall as they will retain extra water in storage in anticipation of the future tight supply situation. Stochastic dynamic programming is a commonly used methodology for hydro-thermal optimisation, but usually requires some aggregation of hydro reservoirs to make the problem tractable. This aggregation results in a loss of information due to the differing patterns of the inflows into various reservoirs, and inability to deal with some types of constraints.

A key feature of the SDDP algorithm is an iterative sampling strategy used to build up a function describing the value of water in storage. This strategy allows the hydro system to be modelled in considerable detail, without the aggregation of reservoirs or hydro plants. Consequently SDDP is well suited to carrying out optimal dispatch simulations of the New Zealand system.

A large range of output results are available from SDDP – over 100 report files can be generated if required. These files are in csv format, and so are suitable for further analysis using Excel spreadsheets. SDDP also includes a reporting module, which can be used to summarise outputs. These summaries are also in Excel spreadsheet format, and have been used to produce the tables and charts for this report.