

# Accelerated electrification

## Technical annex



Interim  
Climate  
Change  
Committee

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## 1. Introduction

The Interim Climate Change Committee (the Committee) is an independent committee established as a precursor body to a proposed permanent Climate Change Commission. To make progress before the Commission is in place, the Committee was asked to provide advice to the Government on planning for the transition to 100% renewable electricity by 2035. The conclusions and recommendations made by the Committee can be found in the main report, *Accelerated Electrification*.

In forming this advice, the Committee commissioned modelling of the electricity system in 2035. The results of the modelling are summarised in *Accelerated electrification*. This technical annex is intended to be read as a supplementary document.

This annex includes further detail on the modelling approach, uncertainty testing, and a selection of other results and insights. In addition, a number of supplementary reports are available, prepared by consultants to the Committee:

- *Integrating Māori Perspectives: An analysis of the impacts and opportunities for Māori of options proposed by the Interim Climate Change Committee* (Whetu Consultancy Group).  
Note that this supplementary report also contains material relevant to the ICCC report *Action on agricultural emissions*
- *Electricity market modelling 2035* (Energy Link)
- *ICCC modelling: Wind and solar profiles* (John Culy)
- *ICCC modelling: Estimated system incremental and marginal costs in 2035* (John Culy)
- *ICCC modelling: Dry year storage options analysis* (John Culy)
- *Modelling retail electricity prices under high renewables, and low-emissions scenarios* (MartinJenkins)

The modelling spreadsheets are also available at [www.iccc.mfe.govt.nz](http://www.iccc.mfe.govt.nz).

All cost figures in this annex are expressed in real 2018 dollar terms unless otherwise specified.

## 2. Modelling approach

### 2.1. The modelling questions

Figure 1 shows the three main modelling questions.

Figure 1: Modelling questions



In the business as usual future, current market conditions and policies continue relatively unchanged along their current path. This provides a reference point for testing the effect of more targeted policy interventions.

In the 100% renewable electricity future, all fossil fuels are deliberately removed from the New Zealand electricity system.

In the accelerated electrification future, the electricity system is used to deliver emissions reductions via fuel switching in transport and process heat. The intent of this future is to test whether a much larger amount of low-emissions electricity can be delivered to achieve a high level of transport and process heat electrification, while keeping electricity prices affordable.

More information on the approach to the modelling questions can be found in *Accelerated electrification*.

## 2.2. The models

In order to answer these three questions, two models were used: *I-Gen* and *EMarket*.<sup>1</sup>

The *I-Gen* model calculates what electricity generation capacity will be required in the future. It builds power plants progressively in order of those which are the cheapest to construct and operate, and which can also, collectively, deliver the required amount of electricity.<sup>2</sup>

The *EMarket* model then takes the power plants built by the first model and calculates how these different power plants are used throughout the year. It does this by simulating market behaviour on a three hourly basis, ensuring supply meets demand.<sup>3</sup>

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<sup>1</sup> These are a combination of electricity system models, owned and run by Energy Link, which are frequently used by organisations in the electricity sector to guide investment decisions.

<sup>2</sup> Model inputs that affect what gets built include assumptions about the retirement of old power plants (e.g. at the end of their useful life, or based on public announcements). All of the models assume a form of perfect foresight, that is, participants in the electricity system have full information about the future.

<sup>3</sup> See also section 2.7.

*EMarket* also simulates demand response, triggered by high electricity prices. It does this by specifying load that can be shed in response to price. Large grid-scale batteries are also included in the model to help to meet peak demand.

More information on the modelling undertaken by Energy Link can be found in *Electricity market modelling 2035* (Energy Link).

### 2.3. Uncertainty in relation to weather years

Understanding the impact of the weather on the electricity system was a core focus of the modelling exercise.

In order to test the generation mix against weather conditions in the *EMarket* model, a variety of weather data was obtained:

- All available 87 years of hydro inflow records (rain and snow melt) (from 1931 to 2017)
- All available 17 years of wind and solar data (from 2000 to 2016)

For the 70 years without wind and solar data, synthetic wind/solar profiles were created – see *ICCC modelling: Wind and solar profiles*. Note that these synthetic profiles were only applied to the operation of large-scale solar in the modelling, whereas for rooftop solar, pre-existing *EMarket* data was used.

For the most recent 17 years, wind/solar and hydro data were matched together. Prior to the last 17 years, the synthetic wind/solar profiles were cycled through the remaining hydro years – with the effect similar to a random allocation. The intent of this data matching was to ensure modelling accounted for the impact of dry, calm, and less sunny years on the electricity system.

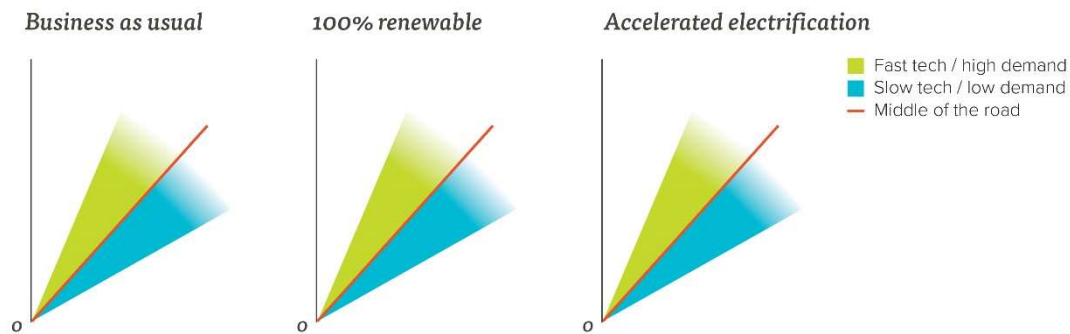
These data were then used to create a dataset of 87 ‘weather years’ against which the generation mix under each future in 2035 was tested.

The weather years were also used to capture the effect of different starting storage levels in the hydro lakes. Model runs were started from 1 January 2034, with a variety of different storage levels, so that by the time 1 January 2035 arrives, the impact of consecutive dry or consecutive wet years is captured (for more detail see section 4.2 of *Electricity market modelling 2035*, Energy Link).

### 2.4. Uncertainty in relation to technology and demand pathways

To understand the effect of uncertainty in relation to technology and demand input assumptions, plausible boundaries of what might occur were identified and modelled for each future. This helps to show, as far as possible, the broad envelope of what might happen by 2035.

These plausible boundaries are referred to as pathways and are described below. However, a general conclusion that can be drawn from the modelling results is that variation in technology and demand has a much smaller impact than variation in weather years (see section 2.3).



Two key dimensions are particularly important for the electricity system and so were chosen as illustrative for this broad envelope: electricity demand and the cost of technology. These are important because they show how much electricity is needed in the future, and some measure of the cost of producing that amount of electricity.

Both electricity demand and technology cost are, in turn, influenced by a range of variables, such as economic growth. The relationship between economic growth, demand and technology costs is complicated. Historically, demand has been tied to growth – so when the economy grew, demand for electricity grew too. This relationship appears to have weakened over time. One of the reasons for this is because of improved energy efficiency.

Electricity demand and technology costs will also be influenced by what happens both domestically and internationally. For example, if there is ambitious and coherent climate change policy globally, it is likely to drive investment in relevant research, development and innovation, which will lower technology prices (noting that the correlation between the ambition of climate change policy, technology development and economic growth varies by country).

To look at this range of possibilities, three hypothetical pathways were applied to each future (and model inputs were varied accordingly):

- **Slow tech/low demand:** This pathway represents a situation where there is a less ambitious approach to climate change policy internationally. In response, the rate of technology change slows, and the costs of relevant technologies imported into New Zealand do not come down as quickly as expected. This pathway also represents a situation where there is slower economic growth, leading to lower electricity demand. This is partially represented in the model using the proxy of the closure of New Zealand Aluminium Smelter's plant at Tiwai Point before 2035.<sup>4</sup>
- **Middle of the road:** This pathway represents a situation where there is a relatively moderate approach to climate change policy internationally. In response, technology change continues as per current estimates, and the costs of relevant technologies imported into New Zealand come down. This pathway also represents a situation where economic growth continues at a

<sup>4</sup> This is not predicting that the smelter will close, rather it is a proxy to illustrate a plausible situation explaining a substantial drop in electricity demand.

moderate pace, leading to moderate electricity demand. Most of the results in the main report show the middle of the road pathway.

- **Fast tech/high demand:** This pathway represents a situation where there is a more ambitious approach to climate change policy internationally. In response, technology change gathers pace, and the costs of relevant technologies (like solar panels or wind turbines) imported into New Zealand comes down sooner. This pathway also represents a situation where there is also higher economic growth, leading to higher electricity demand.

Together, these pathways are intended to represent the plausible bounds of an overall envelope of possibilities. Within this envelope, other pathways are possible (e.g. slow tech/high demand), but they are captured within the edges of the envelope as represented by slow tech/low demand and fast tech/high demand.

These possible pathways represent a combination of different model inputs. For example, it is not just that the demand from electric vehicles (EVs) changes across the three futures, but that the demand from EVs and process heat, total demand growth, amount of solar generation, and costs of power plants *all* change.

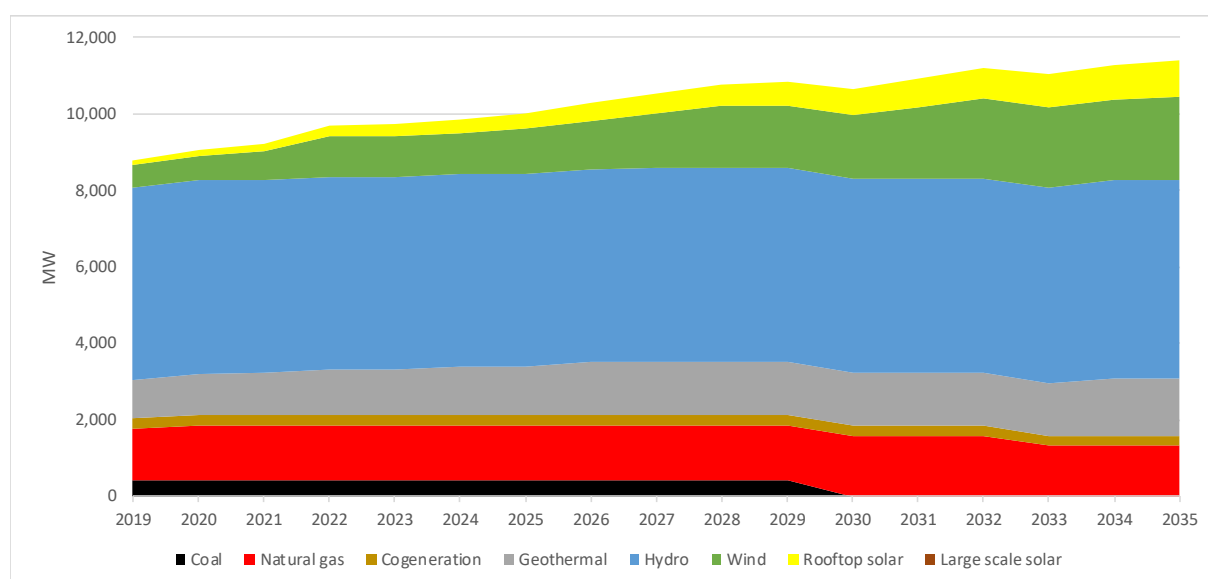
## 2.5. Modelled time period

In the business as usual future, the *I-Gen* model was used to project the electricity system forward between now and 2035. In other words it showed for each year the mix of generation to 2035 (Figure 2). Figure 2 shows the installed capacity, rather than the generation by technology.

However, it is not an accurate prediction of the actual generation mix through time, like any forecast, the actual mix of generation may be different to that shown. It should not be read as predicting that particular plant is built or retired in any specific year. Actual commercial build and retirement decisions will be different within this time period. Additionally, investors will look beyond 2035 when making decisions.

For the other two futures (100% renewable electricity and Accelerated electrification), single year snapshots of the electricity system in 2035 were modelled. This enabled more detailed analysis of the generation mix in 2035 under different assumptions (e.g. the sensitivity run results as shown in section 4.2).

Figure 2: Installed capacity under business as usual, 2019 to 2035



For all three futures, the 2035 year was then modelled for each of the 87 weather years (see section 2.3).

## 2.6. How the modelled wholesale price was derived

The modelling produces two measures of cost. First, the system marginal cost. This can be used to derive expected wholesale electricity prices, which in turn are used to estimate the modelled wholesale price. This marginal cost is based on spot prices calculated based on generation offered and dispatched every three hours. This is done for each of 87 historical weather years at 221 nodes.<sup>5</sup> The calculated spot prices account for variations in demand and weather, modelled transmission constraints, and marginal transmission losses.

More detail on system marginal cost can be found in *Electricity market modelling 2035* (Energy Link).

The modelled wholesale price is the price required to support the cost of the lowest cost new generation required in the target year. It is the “firm flat<sup>6</sup>” contract price that would be required in 2035 for the cheapest marginal new source of supply (assumed to be wind) to cover its annualised capital and operating costs. This includes an allocation of the cost of batteries and the costs of intermittency as reflected in the modelled GWAP/TWAP ratio<sup>7</sup>, and the impact of wind ‘spill’.

The second measure of cost is the total annualised system cost of operating the electricity system. This is used to estimate the cost of each step moving towards 100% renewable electricity, and the implied emissions abatement cost (equal to the increase in annual system cost divided by the reduction in annual emissions).

<sup>5</sup> A node is a grid injection (GIP) or grid exit point (GXP) across New Zealand at which electricity is traded. Generators make offers to supply electricity at GIPs (where their power stations connect to the national grid), and retailers and major industrial users made bids to buy electricity at GXPs (typically where the national grid connects to a local network).

<sup>6</sup> Fixed volume, flat contract.

<sup>7</sup> Generation weighted average price to time weighted average price.



More detail on the costs can be found in the report *ICCC modelling: Estimated system incremental and marginal costs in 2035* (John Culy).

## 2.7. Modelled time-step

The modelling was completed using three hour time steps, meaning each inflow year was modelled and solved to that level of granularity. See *Electricity market modelling 2035* (Energy Link) for further information. The results were assessed for how each future performed in terms of meeting peak demand in winter.

One modelling run was completed for the business as usual future using a one hour step. This one hour step version of the business as usual was completed to check that no system issues were being overlooked by the three hour time step, and there was no significant discrepancy between the results.

The results were consistent between the two runs of the business as usual future across total generation, system cost, spill, GWAP/TWAP ratio and wind required TWAP. The only change that was noteworthy was in the revenue of the peaking plant and batteries. Both recovered more revenue under the one-hour time step because the greater level of detail allowed for more opportunity to take advantage of prices.

## 3. Model inputs

### 3.1. Future and pathway inputs

Table 1 below sets out all of the model inputs for each future and pathway. There are two common assumptions to all futures (both of which are tested in the sensitivity run analysis):

- Gas price: \$9.50/GJ by 2035
- Emissions price: \$50/tonne of CO<sub>2</sub>e by 2035, following the same trajectory as used in Productivity Commission's *Low-emissions economy* modelling

Table 1: Model inputs

Futures	Underlying demand growth per year from 2018-2035 <sup>8</sup>	Batteries deployed by 2035 (MW)	EV demand in 2035 (TWh)	Process heat demand in 2035 (TWh)	Rooftop solar in 2035 (TWh)	Large scale solar cost decline per year from 2018-2035 <sup>9</sup>	Wind cost decline per year from 2018-2035	Existing fossil fuel generation retired	New Zealand Aluminium Smelter closes?
Business as usual – slow tech/low demand	-0.1%	100	1.7	0.1	0.5	-1.55%	None	Huntly Rankines, Taranaki Combined Cycle (TCC)	Yes
<b>Business as usual – middle of the road</b>	<b>0.5%</b>	<b>200</b>	<b>2.7</b>	<b>0.6</b>	<b>1.1</b>	<b>-3.1%</b>	<b>-0.5%</b>	<b>Huntly Rankines, TCC</b>	<b>No</b>
Business as usual – fast tech/high demand	1.0%	350	3.8	2.5	3.0	-4.05%	-0.9%	Huntly Rankines, TCC	No
<b>Step 1 – 96% renewable – middle of the road</b>	<b>0.5%</b>	<b>350</b>	<b>2.7</b>	<b>0.6</b>	<b>1.1</b>	<b>-3.1%</b>	<b>-0.5%</b>	<b>As for business as usual plus Unit 5</b>	<b>No</b>

<sup>8</sup> See Table 2 for components.

<sup>9</sup> Average of the following decrease in cost modelled:

- Slow tech/low demand – 2.25% decline per year to 2025, then 1% decline per year to 2035
- Middle of the road – 4.5% decline per year to 2025, 2.0% decline per year to 2035
- Fast tech/high demand – 6% decline per year to 2025, then 2.5% decline per year to 2035.

Futures	Underlying demand growth per year from 2018-2035 <sup>8</sup>	Batteries deployed by 2035 (MW)	EV demand in 2035 (TWh)	Process heat demand in 2035 (TWh)	Rooftop solar in 2035 (TWh)	Large scale solar cost decline per year from 2018-2035 <sup>9</sup>	Wind cost decline per year from 2018-2035	Existing fossil fuel generation retired	New Zealand Aluminium Smelter closes?
Step 2 – 98% renewable – slow tech/low demand	-0.1%	100	1.7	0.1	0.5	-1.55%	None	As for 96% renewables plus fossil fuel cogeneration	Yes
<b>Step 2 – 98% renewable – middle of the road</b>	<b>0.5%</b>	<b>350</b>	<b>2.7</b>	<b>0.6</b>	<b>1.1</b>	<b>-3.1%</b>	<b>-0.5%</b>	<b>As for 96% renewables plus fossil fuel cogeneration</b>	<b>No</b>
Step 2 – 98% renewable – fast tech/high demand	1.0%	350	3.8	2.5	3.0	-4.05%	-0.9%	As for 96% renewables plus fossil fuel cogeneration	No
<b>Step 3 – 99% renewable – middle of the road</b>	<b>0.5%</b>	<b>350</b>	<b>2.7</b>	<b>0.6</b>	<b>1.1</b>	<b>-3.1%</b>	<b>-0.5%</b>	<b>As for 98% plus McKee</b>	<b>No</b>

Futures	Underlying demand growth per year from 2018-2035 <sup>8</sup>	Batteries deployed by 2035 (MW)	EV demand in 2035 (TWh)	Process heat demand in 2035 (TWh)	Rooftop solar in 2035 (TWh)	Large scale solar cost decline per year from 2018-2035 <sup>9</sup>	Wind cost decline per year from 2018-2035	Existing fossil fuel generation retired	New Zealand Aluminium Smelter closes?
100% renewable – slow tech/low demand	-0.1%	400	1.7	0.1	0.5	-1.55%	None	All fossil fuel generation and cogeneration	Yes
<b>100% renewable – middle of the road</b>	<b>0.5%</b>	<b>850</b>	<b>2.7</b>	<b>0.6</b>	<b>1.1</b>	<b>-3.1%</b>	<b>-0.5%</b>	<b>All fossil fuel generation and cogeneration</b>	<b>No</b>
100% renewable – fast tech/high demand	1.0%	1,100	3.8	2.5	3.0	-4.05%	-0.9%	All fossil fuel generation and cogeneration	No
Accelerated electrification – slow tech/low demand	-0.1%	350	5.7	5.5	0.5	-1.55%	None	As for business as usual	Yes
<b>Accelerated electrification – middle of the road</b>	<b>0.5%</b>	<b>500</b>	<b>5.7</b>	<b>5.5</b>	<b>1.1</b>	<b>-3.1%</b>	<b>-0.5%</b>	<b>As for business as usual</b>	<b>No</b>

### 3.2. Demand inputs

of the futures.

Table 2 below sets out the three components that make up the underlying demand growth figures for each of the futures.

*Table 2: Components of underlying demand growth*

	Gross Domestic Product growth per year from 2018-2035	Population growth per year from 2018-2035	Energy efficiency improvement per year from 2018-2035
Slow tech/low demand	1.6%	0.6%	0.3%
Middle of the road	2.1%	0.8%	0.5%
Fast tech/high demand	3.0%	1.2%	0.8%

### 3.3. Sensitivity run inputs

Table 3 below sets out each sensitivity run and how the assumptions differ.

*Table 3: Sensitivity assumptions*

Sensitivity run	What is different?	All other assumptions are the same as:
Business as usual – Higher emissions price	Emissions price increases to \$150/t CO <sub>2</sub> e by 2035	Business as usual, except <ul style="list-style-type: none"><li>batteries: 250 MW</li></ul>
Business as usual – Higher gas price	Gas price increases to \$19/GJ by 2035	Business as usual, except <ul style="list-style-type: none"><li>batteries: 250 MW</li></ul>
Business as usual – Constrained hydro	Increased extraction & minimum flows <sup>10</sup>	Business as usual, except <ul style="list-style-type: none"><li>batteries: 250 MW</li></ul>
Accelerated electrification – higher emissions price	Emissions price is \$150/t CO <sub>2</sub> e	Accelerated electrification, with longer battery storage (i.e. more are 12 hour batteries)
Accelerated electrification – peakier demand	Current daily demand profile, with a higher peak to reflect EVs being charged at evening peak (not ‘smart charging’)	Accelerated electrification

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<sup>10</sup> See section 4.3.

## 4. Results

### 4.1. Pathways results

The key results for each pathway are in section 4.5, along with the three main futures for comparison.

New generation needs to be built in all futures and pathways, even in the low demand sensitivities. The minimum amount of new build is 480 MW of renewables in business as usual slow tech/low demand, but there is a net decrease in installed capacity due to the retirement of fossil fuel plant.

The maximum amount of new build needed is 7,940 MW in 100% renewable fast tech/high demand, which is all renewable generation. This illustrates the amount of overbuild needed to replace all fossil-fuel generation in future where technology costs come down faster and demand grows at a higher rate than our business as usual.

### 4.2. Sensitivity run results

The key results for each sensitivity run are in section 4.5, along with the three main futures for comparison.

Of all the sensitivity runs, the accelerated electrification higher emissions price sensitivity run has the highest level of new build at 6,750 MW. This includes new gas peaking plant that more than replaces Huntly's Unit 5 which closes in this sensitivity run.

### 4.3. Hydro constrained sensitivity run

This sensitivity was run to help understand the potential impact of a change in the availability of water for hydro generation. The constraint was applied to the business as usual future.

The approach taken was to focus only on those bodies of water involved in hydro generation, excluding Manapouri and Te Anau.

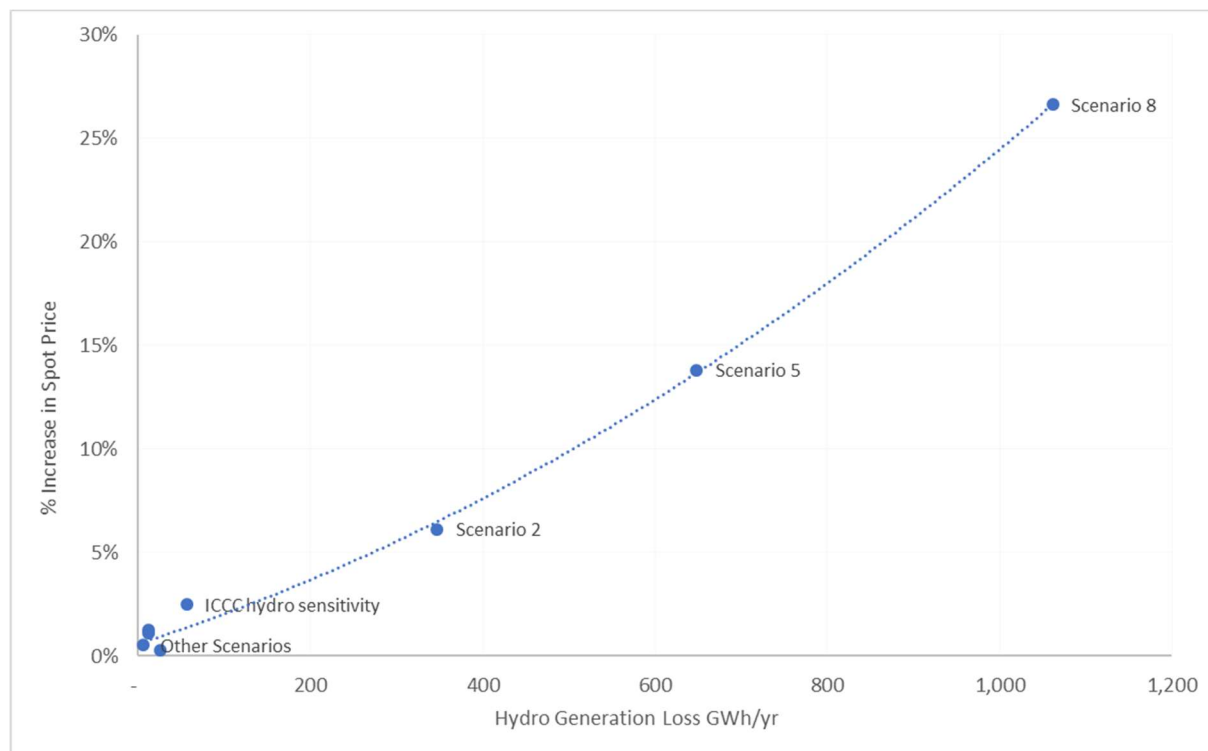
- Apply a 5% increase in minimum flows to the South Island major river systems with hydro generation.
- Apply an increase in extraction of water from the hydro lakes of 2% of average inflows from October to March inclusive to all hydro lakes bar Taupō.
- Apply a 10% increase in minimum flow below Karapiro on the Waikato river.

The results showed:

- A \$2 per MWh increase in the modelled wholesale price of electricity
- The demand response contract between Meridian and the New Zealand Aluminium Smelter would be called in 4 of the 87 weather years, rather than 2 of the 87 weather years as happens in the business as usual future
- A reduction in the spill of water (63 GWh on average) from the hydro lakes and lower generation from hydro
- Little effect on retail electricity prices in 2035
- A 1% increase in average emissions per year.

The results for the hydro sensitivity run are broadly consistent with those of the previous modelling using different input assumptions (Figure 3). This was completed in 2015 for the Ministry for the Environment and Ministry for Primary Industries.<sup>11</sup>

Figure 3: Comparison of the ICCG and Halliburton hydro modelling results



Under the business as usual future, the impact of these reduced flows is moderated by the availability of fossil-fuelled generation to provide flexibility. However, if hydro was constrained under a future with a higher proportion of renewable generation (such as accelerated electrification), the impact of reduced hydro flexibility could become more pronounced.

#### 4.4. Peakier demand

In all futures, the modelling assumes that the additional demand in 2035 follows the same pattern of use and consumption over the 24 hour period as it does today. This is based on an assumption that EV charging is done ‘smartly’ – that is, it is not all done during the evening peak.

The modelling included a sensitivity run which tests this assumption using the future with the highest level of EV demand, accelerated electrification. The ‘peakier demand’ sensitivity run applies the ‘passive’ (i.e. plug-in-when-get-home) charging pattern from Concept Consulting’s “Driving change” report<sup>12</sup> to represent the possibility that there is ‘non-smart’ charging.

<sup>11</sup> Halliburton, T. (2015). Assessment of the impact of flow alterations on electricity generation. Wellington: Ministry for the Environment and Ministry for Primary Industries.

<sup>12</sup> Concept Consulting. (2018). “Driving change” – Issues and options to maximise the opportunities from large-scale electric vehicle uptake in New Zealand. Wellington: Concept Consulting Group Ltd.

The results show that the increase in peak demand is not large enough to have a significant impact on any of the key outputs of the model. However, this modelling does not capture the effect on local distribution networks, which are more likely to be impacted.

The modelled wholesale price increases by \$2/MWh compared with the accelerated electrification result. The implications of this on retail electricity prices are discussed in the supplementary report, *Modelling retail electricity prices under high renewables, and low-emissions scenarios* (MartinJenkins).

#### 4.5. Summary tables

The modelled wholesale prices for each future and pathway are set out in Table 4 below. The implications for retail electricity prices are discussed in the supplementary report, *Modelling retail electricity prices under high renewables, and low-emissions scenarios* (MartinJenkins).

Note that the modelled wholesale prices for the 100% renewable electricity future and pathways are likely to be underestimates because of the amount of non-supply remaining in this future. Additional analysis therefore attempted to identify the cost of resolving this non-supply. See section 4.3 of *Accelerated electrification* and 2.3 of *ICCC modelling: Estimated system incremental and marginal costs in 2035* (John Culy) for further information.

Table 4: Modelled wholesale price for all futures and pathways (\$/MWh)

	2019 <sup>13</sup>	Business as usual	Step 1 (96%)	Step 2 (98%)	Step 3 (99%)	100% renewable electricity	Accelerated electrification
Slow tech/low demand		78	80	-	-	107	87
Middle of the road	80	78	85	87	89	113	85
Fast tech/high demand		80	84	-	-	118	-

The modelled wholesale price for each sensitivity run is set out in Table 5 below.

Table 5: Modelled wholesale price for each sensitivity run (\$/MWh)

Business as usual – Higher emissions price (\$150/t CO <sub>2</sub> e)	88
Business as usual – Higher gas price (\$19/GJ)	85
Business as usual – Constrained hydro	79
Accelerated electrification – higher emissions price	94
Accelerated electrification – peakier demand	87

<sup>13</sup> Estimated based on prices for 2022 contracts, which reflect market expectations of future wholesale prices and the cost of new generation.



The average percentage renewables for each sensitivity modelled is set out in Table 6 below.

*Table 6: Average percentage of renewable electricity for all futures and pathways*

	2019	Business as usual	Step 1 (96%)	Step 2 (98%)	Step 3 (99%)	100% renewable electricity	Accelerated electrification
Slow tech/low demand		91	99			100	92
Middle of the road	82	93	96	98	99	100	92
Fast tech/high demand		93	98			100	

The average percentage renewable for each sensitivity modelled is set out in the table below.

*Table 7: Average percentage of renewable electricity for all sensitivity runs*

Business as usual – Higher emissions price (\$150/t CO <sub>2</sub> e)	97%
Business as usual – Higher gas price (\$19/GJ)	97%
Business as usual – Constrained hydro	92%
Accelerated electrification – higher emissions price	97%
Accelerated electrification – peakier demand	92%

The average annual emissions for each future and pathway is set out in Table 8 below.

*Table 8: Average annual emissions (Mt) for all futures and pathways*

	2019	Business as usual	Step 1 (96%)	Step 2 (98%)	Step 3 (99%)	100% renewable electricity	Accelerated electrification
Slow tech / Low demand		2.1	1.2			1.2	3.2
Middle of the road	4.2	2.8	2.3	2.0	2.0	1.7	3.6
Fast tech / High demand		3.2	2.3			2.0	

The net emissions savings per year is shown in Table 9 below.

*Table 9: Net saving emissions savings per year*

Average annual emissions	(a) Electricity system emissions	(b) Avoided heat & vehicle emissions	Net impact (a) + (b)
Business as usual	2.8	-3.3	-0.5
100% renewable electricity	1.7	-3.3	-1.6
Accelerated Electrification	3.6	-9.0	-5.4

The average annual emissions for each sensitivity modelled is set out in Table 10 below.

*Table 10: Average annual emissions (Mt CO<sub>2</sub>e) for all sensitivities*

Business as usual – Higher emissions price (\$150/t CO <sub>2</sub> e)	1.8
Business as usual – Higher gas price (\$19/GJ)	2.3
Business as usual – Constrained hydro	2.8
Accelerated electrification – higher emissions price	2.3
Accelerated electrification – peakier demand	3.6

#### 4.6. Capacity factors

The capacity factors set out in

Table 11 below are the results of the modelling rather than the nameplate capacity factors for each type of technology. Several factors are at play in these results; for example, technology improvements, relative economics, the mix of generation in the system, and the correlation between different forms of renewable generation.

The 'gas thermal' is Unit 5 at Huntly, which is a combined cycle gas turbine (CCGT) plant that is modelled to operate more like a peaker, resulting in a much lower capacity factor. The capacity factor of a CCGT plant in today's environment is usually about 80%.

The low capacity factors of rooftop solar and large scale solar reflect the reality that it can only generate electricity when the sun is out.

Table 11: Capacity factors and average generation - 2035

	Business as usual - middle of the road		100% renewable		Accelerated electrification	
	Capacity factor	Average annual GWh	Capacity factor	Average annual GWh	Capacity factor	Average annual GWh
Gas peakers <sup>14</sup>	11%	2,620	-	-	13%	3,750
Gas thermal	54%		-		60%	
Cogeneration	50%	1,230	-	560	50%	1,230
Geothermal	90%	11,920	91%	13,560	91%	13,360
Hydro	55%	24,790	51%	23,820	55%	25,810
Wind	40%	7,530	31%	9,160	40%	11,150
Solar	14%	1,180	14%	1,180	14%	1,180
Large scale solar	-		25%	1,000	25%	780
<b>Total</b>		<b>49,270</b>		<b>49,280</b>		<b>57,270</b>

#### 4.7. Spill

Spill occurs where water flows past a hydro power station, or where wind turns a wind turbine, but it is not used to generate electricity. Some amount of spill is inevitable, excess spill in the system means that capital has been invested, but is being under-utilised. This infrastructure has a cost which is passed on to consumers.

Information on the wind spill for the different futures and pathways can be found in the tables of the results section (Chapter 3) of the technical annex *ICCC Modelling: Estimated system incremental and marginal costs in 2035* (John Culy).

Wind spill increases from 7% under the business as usual future to 28% under the 100% renewable electricity future. Under accelerated electrification wind spill is 6%. Hydro-generation is priced lower than wind in terms of spill priority, so wind spills more than hydro as the renewable percentage approaches 100%.

#### 4.8. Price duration curves

The price duration curves for the different futures and pathways can be found in *ICCC modelling: Estimated system incremental and marginal costs in 2035* (John Culy).

### 5. Dry year options analysis

Further information on the dry year options analysis can be found in *ICCC modelling: Dry year storage options analysis* (John Culy).

<sup>14</sup> The diesel generator (Whirinaki) has a capacity factor of 0.2% in both business as usual and accelerated electrification.

## 6. Limitations

As with any modelling exercise, there were limitations.

The models used (*I-Gen* and *EMarket*) are electricity system models, rather than energy-wide sector models. As a result, they are unable to capture the interaction between supply and demand across energy and electricity such as the interactions between transport, process heat, the natural gas system, and industry requirements.

The modelling only includes the transmission network, it does not include distribution networks. This is a recognised limitation because such networks (including the cost of upgrades) could influence the conversion of process heat to electricity.

Finally, as with any model, market learning and evolution cannot be easily captured, partially because it is difficult to predict (in order for it to be put into the model as an input) and partially because of the limitations of the models themselves. For example, how generators offer their electricity supply to the market may change in the future.

See also section 4.13 of *Electricity market modelling 2035* (Energy Link) for more information on the accuracy and limitations of the modelling.

## 7. Peer review and quality assurance

The Committee undertook a number of actions to ensure the modelling was robust. These included:

- Involvement of industry experts in the development of the approach via the E-Charge group
- Academic and technical review of the model inputs (including possible technology price paths)
- Technical workshops to test initial modelling results and help to guide further analysis.

The Committee also shared the model input assumptions with two organisations – the Electric Power Optimization Centre (EPOC) at the University of Auckland and Meridian Energy Ltd. Both organisations then used their own models to run the Committee's input assumptions.

The University of Auckland EPOC model adopted a system optimisation approach, focused on least-cost and zero greenhouse gas emissions. The model identified significant increases in system cost as emissions become more constrained. In general, investments made by a risk-averse social planner were found to meet emission constraints with much lower emissions prices than models that treat risk-averse investors as competing agents. There were some differences in the modelling assumptions that led to different investment choices made by the models. Details of these results and a description of GEMStone can be downloaded from ([www.epoc.org.nz/publications.html](http://www.epoc.org.nz/publications.html))

The purpose of this quality assurance process was to cross check what different models produced when a number of the same input assumptions were used. The results of the models were broadly consistent and did not lead to significantly different conclusions than those drawn in the Committee's main report.