FN-26-05 Fortnightly report 20 March 2026

This report summarises items that may be of interest to the Minister for Energy and Associate Minister for Energy but do not require a formal briefing. Further information can be provided on request. Substantive items and decision papers will be provided by briefing.

Electricity Authority contact: Sarah Gillies, Chief Executive

Mobile: [redacted]

1. Upcoming publications

Responding to upcoming household electricity price rises	
Strategic outcome	Affordable
Purpose	Further increases in retail electricity prices are expected this year. We anticipate average price increases of around 8% (or $22 per month) this year, varying by region and retailer. This compares with increases around 12% (or $28 per month) in 2025. The major influence on retail price increases has been higher transmission and distribution costs, accounting for up to 66% of the most recent increases. This stems from the Commerce Commission's 2025 RCP-DPP4 decision to increase the allowed revenue requirement due to an increase in the WACC, higher allowance for inflation and greater cost recovery for operating expenditure and capital investment. The Authority continues to take actions that put downward pressure on the energy component of electricity bills and help consumers to manage price increase impacts. To address the energy component, we are progressing the level playing field measures, better enabling and rewarding demand flexibility, and enhancing our monitoring and enforcement regime. We are also helping consumers with the impact of higher prices by making electricity bills easier to understand, requiring retailers to offer time-of-use plans and ensure they are on the retailer's best available retail plan, and launching a new, enhanced comparison and switching service (Billy). We are raising consumer awareness about upcoming price increases ahead of winter. We are providing consumers with practical advice about how they can understand and manage their bills, including how to get the most out of Billy. This work complements similar efforts by the Commerce Commission and EECA's Winter Energy campaign, scheduled to begin in May. We will share more information about these price rises and the Authority's response at the next Ministerial meeting.
Action and timing	Information release begins: 26 March – mid-April 2026

Decision – maximising benefits from local electricity generation (export limits)	
Strategic outcome	Affordable
Purpose	The Authority will publish a decision paper amending the Code to require distributors to apply a 10kW default export limit, unless the distributor has a justified reason for applying a lower limit.

	The change will enable consumers to sell more of the solar they generate, help avoid expensive network infrastructure upgrades, and encourage increased solar generation, resulting in lower electricity prices. Please see section 5 for a response to your question on when the remaining EDBs will have 10 kW limits in place.
Action and timing	Planned for 30 March

2. Consultation: Current and future

Current consultation	Consultation period
Level playing field measures: non-discrimination obligations and price consistency	26 February - 24 March
Reducing barriers for new connections: alignment on weighted average cost of capital	3 - 20 March
Consultation on a new Electricity Information Exchange Protocol – EIEP14A	3 - 26 March

Future consultation	Consultation period
Consultation – Improving prudential security arrangements	26 March - 23 April
Reforming distributed generation pricing to promote efficient investment	2 April - 15 May
Omnibus of common quality Code amendment proposals: consultation paper	Mid-April - late June

3. Upcoming Electricity Industry Participation Code 2010 amendments

3.1. The following table has Electricity Industry Participation Code amendments that need to be presented to the House by the Minister's office within 20 working days following the date the amendment is made.

Tracking number	Name	Date made	Date of Gazette notification	Date in force	Due date for presentation to the House
EIPCA-26-007	Frequency and voltage related amendments	10 March 2026	16 March 2026	1 July 2026	9 April 2026

4. Response to your request for information about connection pricing work

4.1. You requested further information on the Authority's connection pricing work and whether upcoming changes may result in distributors charging for services they are currently providing free of charge.

The Authority's work on connection pricing

4.2. Distributors currently have no regulatory constraints when setting the up-front connection charges for new or upgraded network connections. However, the Authority has found that connection charges are not always set at a level to encourage efficient connections. If charges are too high this may be a barrier to electrification, deter new infrastructure or housing developments or push up development costs that then get passed onto consumers. Conversely, if charges are too low, existing consumers may end up subsidising the true costs of new connections.

4.3. We have introduced measures to make distribution connection pricing more efficient, transparent and consistent for consumers. These changes will make pricing more predictable and easier to understand, enabling consumers to see whether their charges reflect the actual cost of connecting, and for larger consumers, to see how their prices compare across regions.

4.4. These measures will come into force on 1 April 2026. A key requirement is that distributors show how connection charges compare with a level that encourages efficient investment.

4.5. These measures are the first steps to encourage efficient connections so that costs fall where they should and consumers face fewer cross-subsidies over time. The Authority has already started further work to reform the broader connection pricing framework.

Impact of the recent measures

4.6. Our recent measures on connection pricing do not require distributors to raise connection prices or begin charging for services that were previously free.

4.7. However, some distributors may not have been recovering the full cost of connection from new customers – suggesting existing customers have been subsidising new connections and paying more than their fair share. This leads to inefficient investment (such as development in locations that are costly for the network to serve), ultimately pushing up long term costs for all consumers. This is an issue the Authority will investigate as part of its connection pricing work this year.

4.8. Some distributors may choose to adjust their charges if they have historically under-recovered connection costs. This would be a business decision for them, not a requirement of the Authority's current proposal.

5. Response to your question about 10 kW limits

5.1. You asked when the remaining EDBs will have 10 kW limits in place. Detail on timeframes is provided in the table below.

5.2. As at 17 March 2026, of the 30 distributors, 23 have a default distributed generation export limit of 10kW (or greater), six are working towards this, and one is not currently considering this. The Authority updates this information monthly in its progress tracker here: [Shift to 10kW export limits | Electricity Authority].

5.3. Under the Authority's export limits-related Code amendments, recently approved by the Board but not yet published (noted in 'Upcoming publications' above), all distributors must offer 10 kW default export limits. This is unless lower limits are justified by a standardised network assessment. Alternatively, distributors can also offer dynamic or flexible limits, only limiting exports below 10 kW when networks are constrained. We intend this Code amendment to be in force by May 2026.

5.4. Wellington Electricity has advised it is not currently considering a move to a 10 kW export limit. We are advised this is due to the density of their network (the highest customer density of all distributors), which makes congestion more of an issue. By November 2026 this will need to be justified by a standardised network assessment.

5.5. However, it is unlikely a 5 kW limit would be required across Wellington Electricity's whole network, so we expect some proportion of its consumers will be able to export at 10 kW following our Code change. Further, we understand the distributor is investigating applying dynamic or flexible limits, which, once developed, would allow consumers more scope for export at higher levels.

5.6. Should Wellington Electricity not be able to justify a 5 kW limit to any part of its network through a network assessment after the 10 kW default is in force, if they stayed at 5 kW they may be in breach of the Code, and we could start compliance proceedings.

Distributor progress towards 10 kW export limit

Legend

Already have a default export limit of 10kW (or greater)

Working towards a default export limit of 10kW (or greater)

Not currently considering a default export limit of 10kW (or greater)

Distributor	As at 17 March	Expected timeframe to 10 kW[1]
Alpine Energy		Develop implementation plan by March 2026
Horizon Networks		Between 1 April and 1 September 2026
Marlborough Lines		Mid-2026
Orion NZ		1 April 2026
Top Energy		1 April 2026
Vector		1 July 2026
Wellington Electricity		No plans to adopt 10kW default

[1] When announced, our Code amendment may result in EDBs bringing forward their implementation timeframe.

Aurora Energy, Buller Electricity, Centralines, Counties Energy, Electricity Ashburton, Electra, Electricity Invercargill. Firstlight Network, Lakeland Network, MainPower NZ, Nelson Electricity, Network Tasman, Network Waitaki, Northpower, OtagoNet, Powerco, Scanpower, The Lines Company, The Power Company, Unison Networks, Waipā Networks, WEL Networks Westpower		**All have a default export limit of 10kW (or greater)**

6. Investment pipeline monthly update: 20 March 2026

Generation investment pipeline snapshot				
45.7GW total capacity	67.6TWh/yr total energy	285 projects	106 developers	83.1% intermittent renewable

Key changes since last update on 19 February

- ► 868MW of new generation commissioned since November 2023 (no change since last update).
- ▲ 1,293MW is currently under construction (+26MW since last update).
- ▲ 38.8GW of projects progressed beyond the first stage of Transpower's grid connection process (+0.2GW based on correction to the data). Of those, 17.4GW are planned for completion before 2030 (+0.2GW based on correction to the data), and of these, 12.9GW are owned independently.

Executive summary

6.1. Along with our regular key project development update, this month we include an update on the pace of generation being built relative to demand. In summary:

(a) Generation built in the last 3 years (2022-2025) was more than double that built in previous 8 years (2015-2022)

(b) Generation build is expected to outpace demand growth – building generation faster than demand growth will help support security of supply, including in dry years.

(c) Overall, we are 509MW better off this winter compared to this record peak from August 2023.

(d) Both gentailers and independent developers are building new generation and different development options are being utilised.

Key project development updates

6.2. A final investment decision has been made for the 25.6MW **Kapuni wind farm** (a joint venture between Hiringa Energy, Balance Agri-Nutrients, Todd, Parininihi ki Waitōtara and MBIE). Construction has begun and completion is expected in 2027.

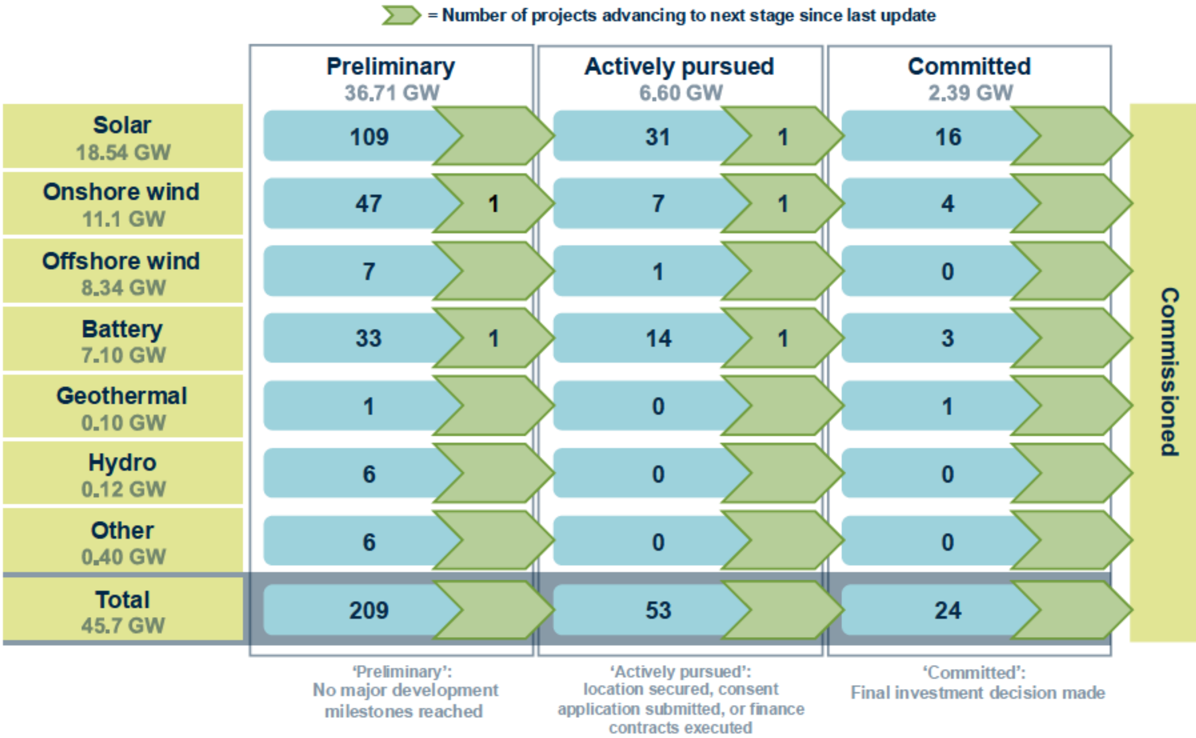
6.3. Contact Energy announced final investment decisions on two projects:

(a) 150MW **Glorit solar farm** – due to be completed in Q3 2028

(b) 200MW **Glenbrook battery 2.0** – due to be completed Q1 2028 (additional to the 100MW already under construction and due Q1 2026).

6.4. A fast-track panel established to consider an application for Poutini Ngāi Tahu and Westpower's 23MW **Waitaha run-of-river hydro** project on the West Coast has released a draft decision approving the project. They noted that it would "have at least significant regional benefits".

Figure 1: Project advancement since 19 February 2026



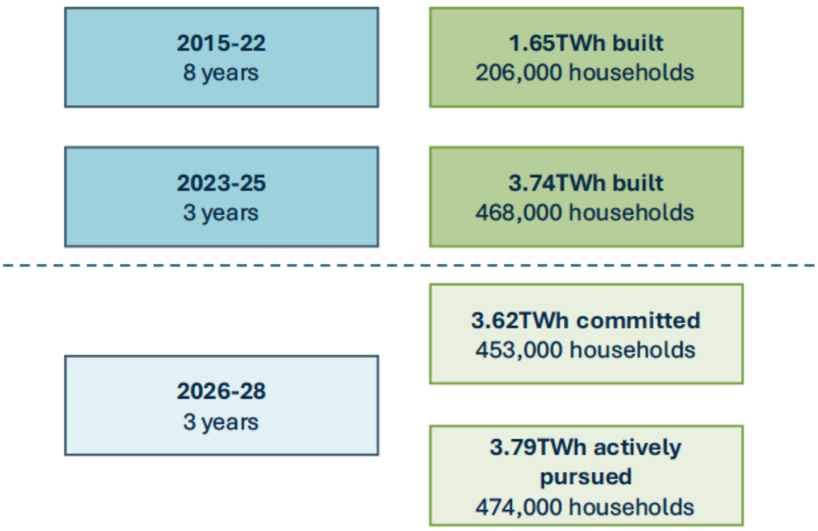
Generation built in the last 3 years was more than double that built in previous 8 years

6.5. The volume of new generation built in the three years 2023-25 (3.74TWh) was more than double that built in the previous 8 years (1.65TWh).

6.6. This rate is expected to continue, with 3.62TWh of committed generation expected in the next three years, and another 3.79TWh actively pursued.

6.7. Committed projects are very likely to be built as they have had a final investment decision made by the developer. Actively pursued projects depend on multiple factors including the outcome of consent applications and market conditions.

Figure 2: Generation built since 2015 compared to the next three years of projects in the pipeline

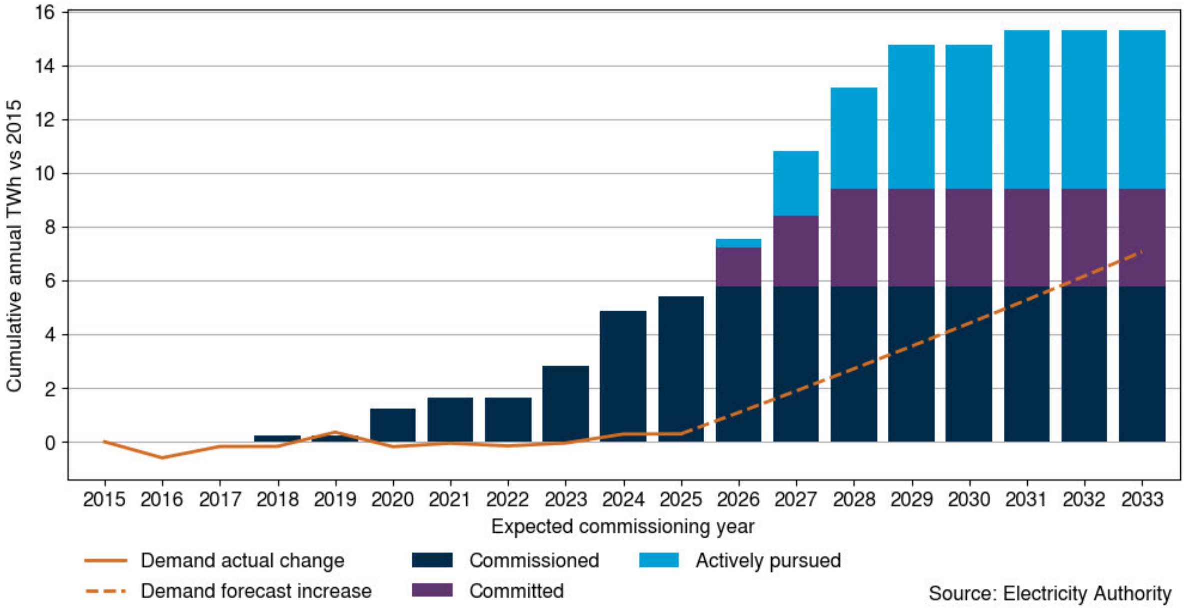


Generation build is expected to meet demand growth, but neither will be linear

6.8. Figure 3 compares the cumulative effect of generation built in the last ten years and new projects in the pipeline against historic demand change (solid orange line) and forecast future demand growth (dashed orange line).

6.9. We assume an average capacity factor for each type of generation to calculate total energy in the pipeline (with batteries providing zero energy).

Figure 3: Cumulative generation pipeline versus 2015 against real and forecast demand change

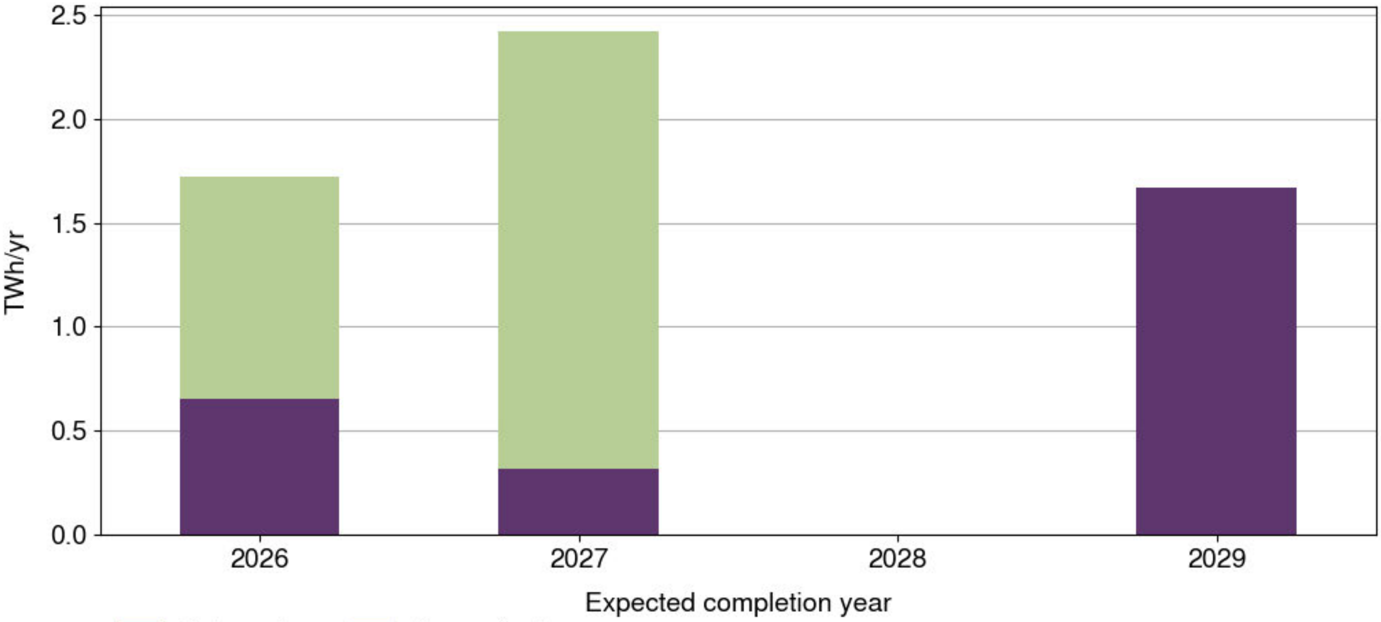


6.10. Demand growth has been relatively flat in the last ten years but has begun to increase recently.

6.11. Already commissioned new generation and committed new generation is sufficient to meet the forecast increase in annual demand included in MBIE's reference case (~0.8-0.9TWh additional demand per year).

6.12. However, demand growth is unlikely to be linear. Industrial electrification will contribute to step changes in demand. Figure 4 shows the annual demand of load projects in our pipeline that are beyond Transpower's first stage. This includes the NZ Steel arc furnace (expected to add ~0.26TWh/yr), Fonterra Whareroa electrification [redacted] and the Datagrid data centre in Southland (expected to add ~1.7TWh/yr), expected in 2029. As with generation projects in the pipeline, not all projects will necessarily be built.

Figure 4: Annual demand from load projects that have progressed beyond the first stage of Transpower's grid connection process



Source: Electricity Authority

6.13. Demand forecasts are simply an estimate and are subject to uncertainty. However, the current trend illustrates that forecast supply is currently outpacing forecast demand, which helps support downward pressure on wholesale prices.

Overall, we are 509MW better off this winter compared to this record peak from August 2023 (assuming no unplanned significant generation outages)

6.14. Figure 5 shows that despite the retirement of Contact's TCC, a pessimistic assumption of no wind generation being available, and an assumed 2% increase in peak demand, we are better placed to meet peak demand this winter than the record peak period in August 2023. Some key points in figure to note:

(a) The August 2023 peak period had spare capacity in the form of controllable hot water and generation not dispatched. This is now available and totals 488MW.

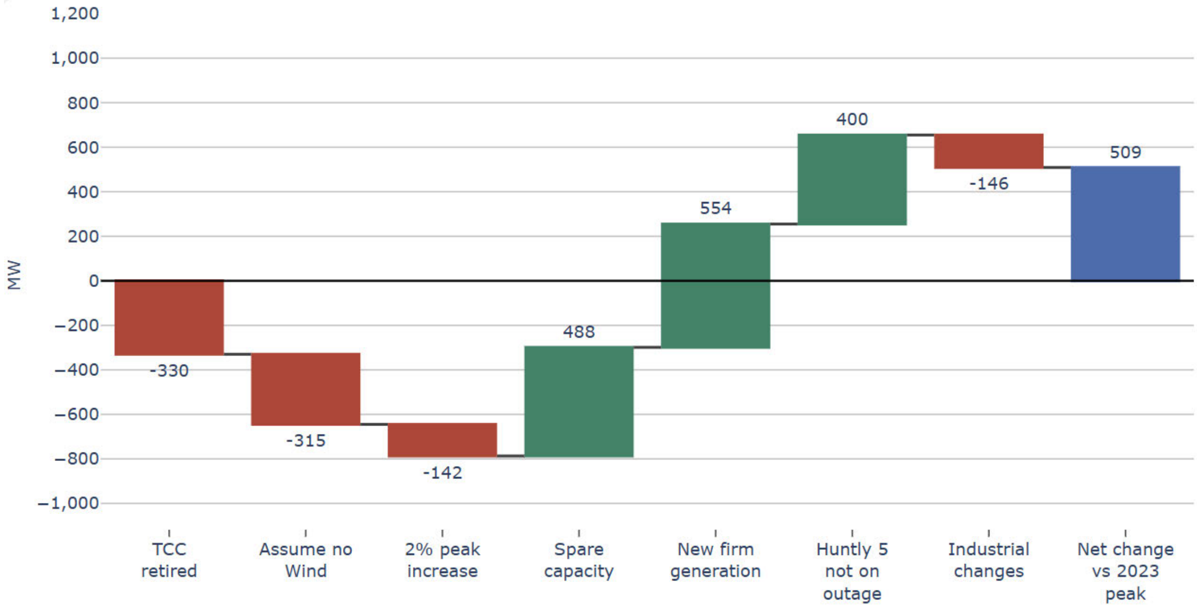
(b) Firm generation built since 2023 is now available or expected to be completed before winter this year improves capacity by 554MW (this includes Tauhara, Te Huka 3, TOPP2 and Ngā Tamariki geothermal stations, and Rotohiko, Ruakākā and Glenbrook batteries).

(c) Huntly 5 was on outage in 2023 but is available for this winter, improving generation capacity by 400MW.

(d) Industrial changes include closures and commissioning/electricification of existing sites like Fonterra results in a net *increase* to peak demand of up to 146MW.

6.15. There are also additional geothermal and battery projects in the pipeline which are expected for completion in 2027 and 2028 (436MW committed).

Figure 5: Winter 2026 generation capacity available compared to record peak from August 2023



Both gentailers and independent developers are building new generation and different development options are being utilised

6.16. Figure 6 illustrates the locations and timelines of the committed projects that have begun construction or commissioning.

6.17. Independent developers are contributing a similar percentage to new capacity build as in recent years. Over the past two years they built 34% of the new capacity – and currently have 25% of the committed capacity in the pipeline (Figure 7).

Figure 6: Map and expected commissioning timeline of projects under construction

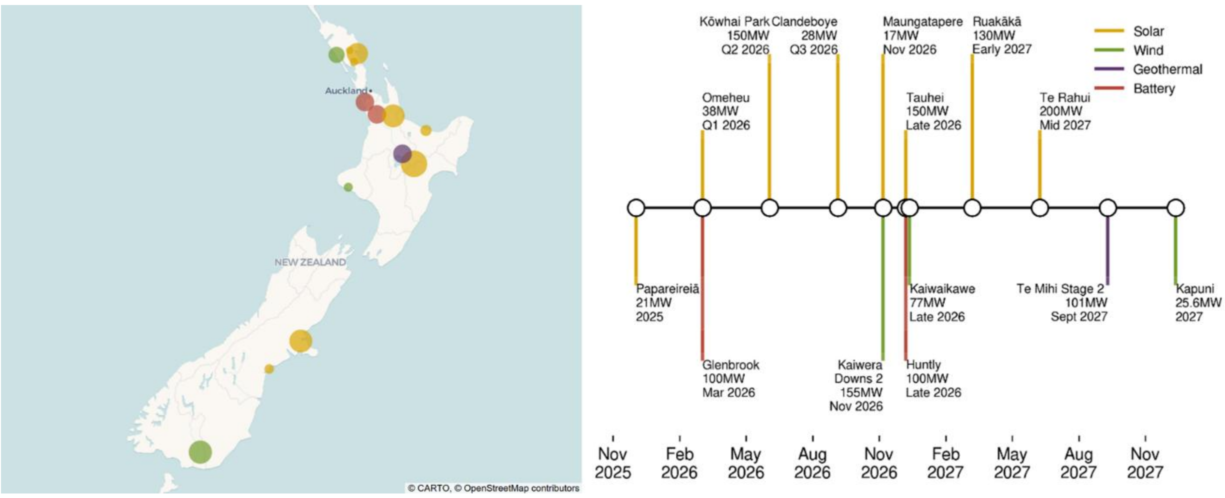


Figure 7: Generation capacity built and in the pipeline by major gentailers and other developers

	Major gentailers	Others
2018-23 6 years	**5 projects built** 574MW (73%)	**5 projects built** 219MW (27%)
2024-25 2 years	**5 projects built** 418MW (66%)	**8 projects built** 214MW (34%)
2026+ Committed	**13 projects** 1,777MW (75%)	**11 projects** 608MW (25%)

6.18. This does not necessarily mean all this new build will operate under independent generators. Within a competitive market, there are various options for the development process:

(a) create an initial concept for development to sell

(b) create and develop the project to completion but sell once it becomes operational, and

(c) create, develop and subsequently operate the new generation.

6.19. We will continue to closely monitor the uptake of these different routes – if any one route becomes less frequent this may indicate potential barriers.

6.20. Two committed projects and one actively pursued project are being developed by independents but have either been purchased by a gentailer or a gentailer has a power purchase argeement for all of the electricity produced:

(a) Genesis is planning to acquire the Rangiri and Leeston solar farms from independent developers.

(b) Meridian has signed a power purchase agreement for all the generation from the Tauhei solar farm.

6.21. Some independent developers have already brought new generation to the market in the last couple of years and are now operating this generation:

(a) Lodestone solar (four solar farms operational)

(b) Eastland generation (one new geothermal station in addition to their existing two)

(c) Ranui generation, Far North Solar Farms, Newpower and Northpower (one solar farm operational each)

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