Generation investment survey

2023 update

Prepared for the Electricity Authority

Key points

1. **New build costs have risen but are still below futures contract prices**
   - We believe the cost of new supply has risen to ~90 $/MWh (baseload equivalent at Otahuhu) due to tight supply chains (especially for wind) and higher interest rates. These higher costs are a headwind for developers.
   - While ASX futures prices show a declining forward profile, they are well above our estimated cost of new supply to 2027. The gap between costs and futures prices is a much narrower at Benmore than Otahuhu (noting Benmore Cal 2027 prices are around 25% below Otahuhu Cal 2027 prices).
2. **Pipeline of potential developments have grown further**
   - Committed generation has lifted significantly compared to the last survey, with its annual output capability (once built) rising from 2,600 GWh to nearly 5,000 GWh. This is slightly more than the amount of generation required to displace the uneconomic thermal generation on the system. The annual development rate (based on projects that have been completed or committed) for the period 2021-2025 is over three times the annual development rate achieved during 2011-2020.
   - There has also been a step up in the pipeline of "actively pursued" generation that could be completed by 2027 (mostly solar and wind) compared to last survey. The annual generation capability of projects in this category has risen from 12,700 GWh to 20,800 GWh.
   - There has been a surge in development of distributed generation, including large utility-scale projects, but also growth in mid-scale and small-scale solar activity, although this makes up a relatively small proportion of the generation pipeline.
   - Most developers are pursuing solar, wind or geothermal projects. There is some interest in batteries and other flexible plant (e.g. biofuels) but it is currently limited.
3. **Investment requirements and demand outlook**
   - In addition to what has been completed or committed, we estimate that new generation with an annual output of 1,700 GWh will need to be built by 2025. This generation is needed to meet projected demand growth (as there is sufficient committed generation to displace uneconomic thermal generation). This figure has decreased from last year's estimate (of just over 3,000 GWh), mostly due to the increase in committed generation since last year's survey.
   - Extending our analysis to 2027, we estimate that new generation (on top of what has already been completed or committed) with an annual output of 2,700 GWh will need to be built by 2027. This generation is needed to meet projected demand growth and to replace lost generation from the retirement of the Wairakei station.
   - With sufficient generation projects now built/committed to displace uneconomic thermal, the timing of further renewable development is expected to be demand-led.
   - Demand growth can be lumpy and hard to predict, so these active projects will need to be nimble and able to respond to demand growth quickly.
   - On the positive side, there seem to be a slew of projects at (or close to) final investment decision, possibly waiting on an announcement regarding the future of the Tiwai smelter. However, developers' ability to quickly change gears if required is impaired by a range of factors – most notably consenting and connection processes (as discussed further below).

Key points (continued)

4. **Factors hindering faster development**
   - Environmental consenting processes remain a critical factor affecting the generation pipeline and development rate. There has been strong uptake of the RMA fast-track option in the last 12 months – that window is now closed, but the new Natural and Built Environments Act potentially offers a similar alternative pathway.
   - Concerns about application of Overseas Investment Act regime have substantially reduced, although costs and timeframes remain a factor for some developers.
   - Connection to the grid tended to be the most significant barrier identified by developers, although most considered Transpower's queueing system to be an improvement. Connection at the distribution level is also an issue – at this stage this is more due to resourcing and learning curves, but network pricing and regulatory settings will be become more important for future waves of investment.
   - Demand outlook is becoming more of a focus, as the driver of renewable investment shifts from thermal displacement to demand. Demand has been relatively flat historically, and although there is consensus it will increase significantly by 2050, exact timings are uncertain. Uncertainty about the Tiwai smelter affects development timing for some projects, but is seen as a temporary factor.
   - Developers expressed a variety of views regarding the necessity of securing power purchase agreements pre-final investment decision. While the PPA market is not deep, there are signs it has developed in the last 12-18 months.
   - Tight markets for equipment and labour remain key challenges for developers, putting upward pressure on build costs – especially for wind projects.
   - Capital remains available for projects but at a significantly higher cost – the softer NZD is also putting upward pressure on costs.
   - Policy and regulatory uncertainties were raised by developers as a concern but were not front of mind for most parties of renewable projects – but were of more concern for developers of flexible supply.

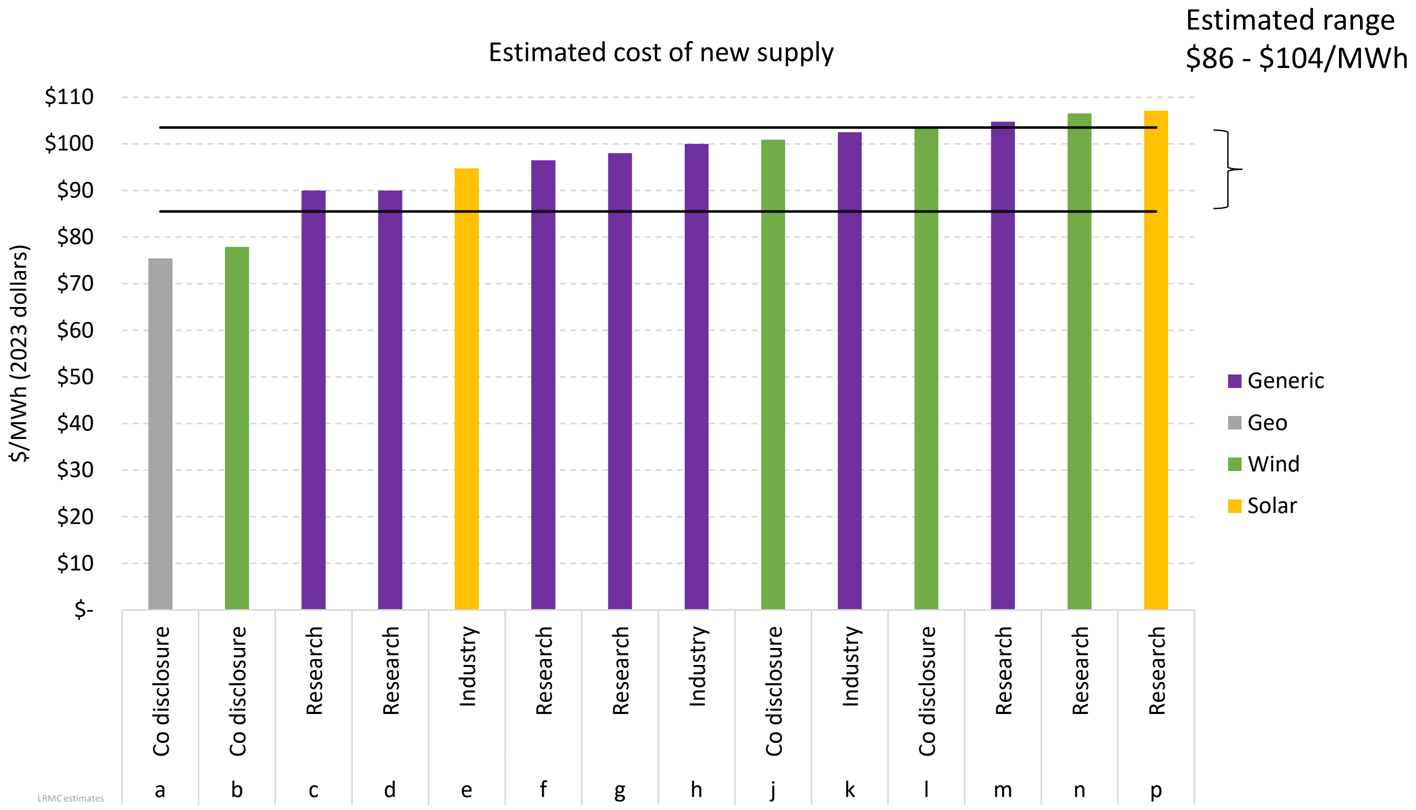
5. **Issues for future consideration**
   - Reduce pipeline friction. Existing arrangements are not well suited to achieving generation development at pace. Furthermore, friction is likely to increase in some areas as pre-existing system headroom is used up. The Authority should consider options to address friction in connection and network expansion processes. It should also support other agencies to further streamline environmental and overseas investment consenting processes.
   - Improve pipeline information. Public information about the pipeline has improved but remains fuzzy in key areas. For example, it appears around 1,400 GWh of new projects are in construction or committed for development, but this status is not necessarily clear in public sources. This difference is material and equates to more than one year of national demand growth. Developers, customers and other stakeholders need clearer, and more timely information on project status to reduce the likelihood of surprises, which could disrupt investment confidence.
   - Active monitoring. Forward prices have a declining profile over time but remain above the estimated cost of new supply. There is no evidence from this survey that major participants are impeding the pace of new supply expansion. Indeed, they are all actively pursuing their own projects, and there are also examples where some have supported independent competitor projects, via offtake agreements, firming contracts or joint ventures etc. Nonetheless, it remains important for the Authority to continue its active monitoring of competition in new investment and offtake agreement areas, since timely new investment is the best solution to address current tight supply conditions. A particular issue the Authority could consider in this context is the cause of the rising premium in forward prices at Otahuhu relative to Benmore.

How do forward contract prices compare with estimated cost of new supply?

We believe the cost of new supply has risen to around 86 – 104 $/MWh (baseload equivalent at Otahuhu)

Key points

- We estimate the cost of new supply to be around 90 $/MWh (2023 dollars).
- Our current estimate has increased compared to previous analysis (central estimate was 84 $/MWh in 2023 dollars).
- This estimate is for new supply coming on stream mid- to late-decade, expressed in baseload equivalent terms at Otahuhu.
- This estimate is compiled from a range of sources including:
  - Company disclosures
  - Industry sources
  - Primary research
- While 90 $/MWh is our central estimate, we see heightened upside risk for the next few years (see later slides) – for this reason, we apply an uncertainty range of -5% to +15% equating to 86-104 $/MWh (2023 dollars).
- We think most industry estimates lie in a similar range, although some parties we spoke to considered the cost of new supply to be significantly higher.
- Key reasons for increase in new supply costs are set out on later in this pack.

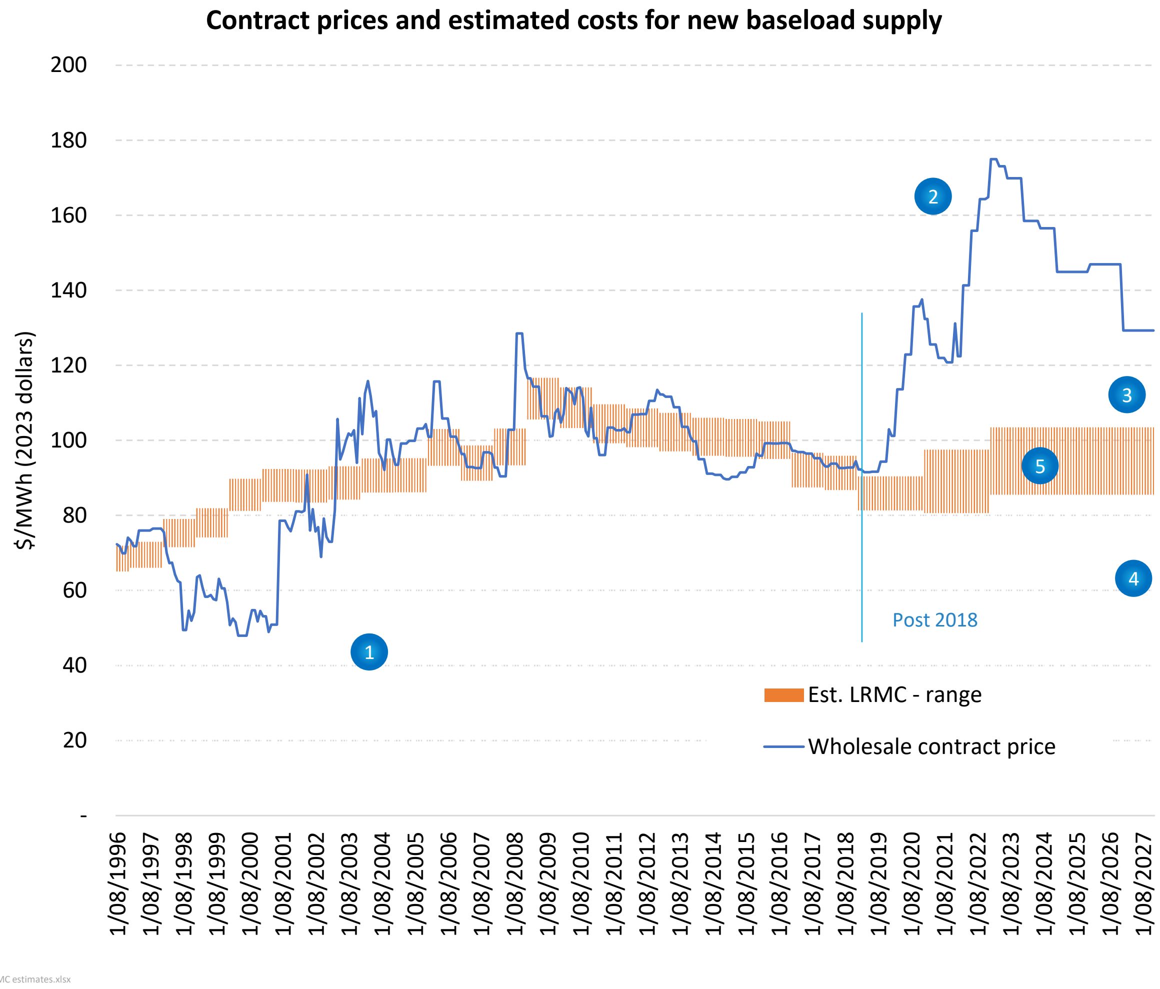


Notes

- All estimates have been converted to a base load equivalent cost at Otahuhu in 2023 dollars
- Co disclosure = the estimate uses information drawn from company disclosures to media or stock exchange
- Industry = the estimate uses information drawn from discussions with industry experts.
- Research = the estimate uses information drawn from external research reports
- GWAP = Generation weighted average price, TWAP = time weighted average price. The GWAP/TWAP ratio indicates the proportion of the baseload i.e. TWAP) price captured by a generation type. It has been estimated from historical data and forecast projections.
- Survey interviews did not seek information on the estimated cost of new supply and have not been used as a source for this analysis.

While ASX futures prices show a declining forward profile, they are well above our estimated cost of new supply to 2027

- Until 2018 contract prices tracked relatively closely to the estimated cost of new baseload supply (albeit with fluctuations at times).
- Since 2019, contract prices have been significantly above the estimated cost of new supply.
- While forward contract prices for 2023- 2027 are trending downwards, they are still well above the estimated cost of new supply.
- The new supply cost range is an *estimate* – the range on the chart has widened post-2020 to reflect:
  - Increased uncertainty about costs of plant (especially wind and solar) in the next few years due to supply chains issues
  - Increased uncertainty about construction costs due to tight markets for contractors and specialized equipment
  - Increased uncertainty about the cost of firming intermittent renewable generation.
- Notwithstanding the uncertainty about the estimates, OTA futures prices clearly exceed longer-run costs of new supply



Notes

- Pre-2019 data is from Electricity Price Review Technical Paper – see www.mbie.govt.nz/dmsdocument/4334-electricity-price-review-first-report-technical-paper
- Contract prices post 2019 are for futures contracts quoted on ASX. Excludes data for contracts trading within one year of commence (to exclude hydrology influences). Data are deflated using CPI, with inflation for future years from Treasury forecasts.
- Estimated costs for new baseload supply post-2019 are derived by Concept from multiple sources. See other slides.

Futures prices at OTA are higher than in NEM until 2026, but after that the relativity varies by region

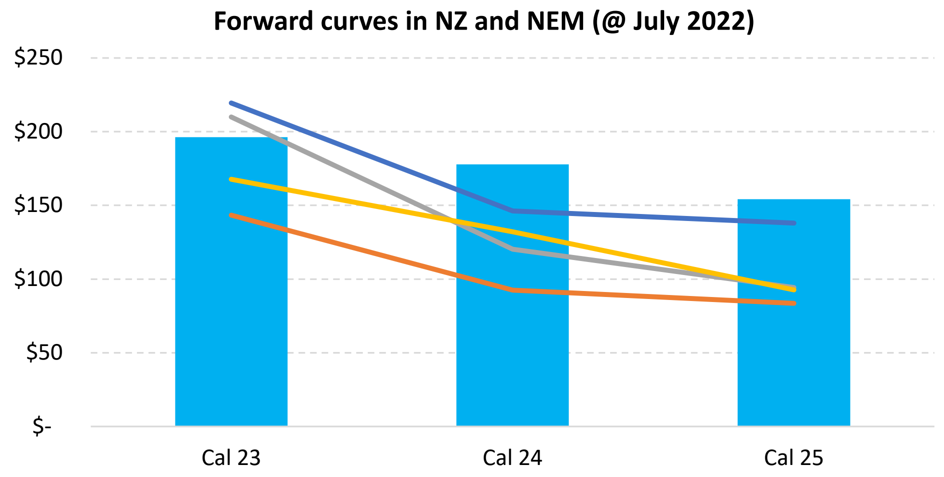
- In the preceding survey we compared NZ baseload futures prices with the Australian National Electricity Market (NEM) – noting some influences are different to NZ.

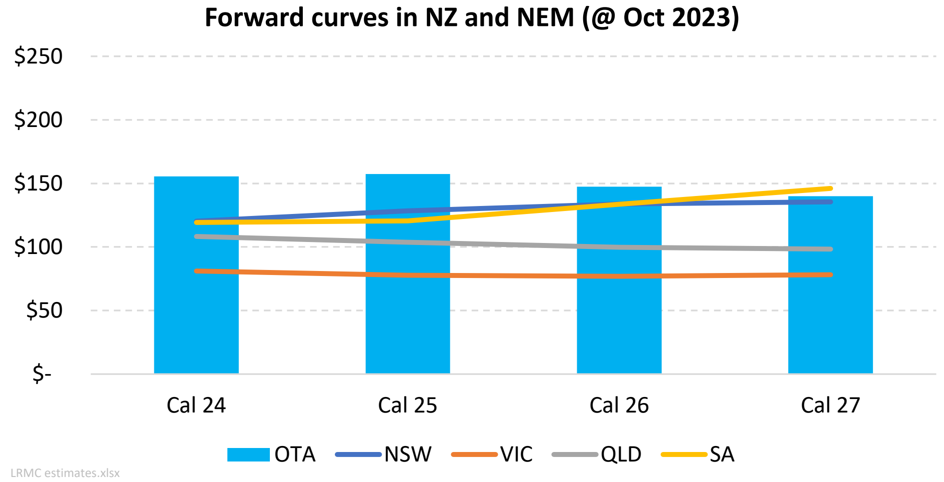
Picture in mid-2022

- The data in mid-2022 had contract prices in the NEM showing a similar forward profile to NZ, with near term elevation and a declining trend.
- However, contract prices in the NEM were trending toward ~100 NZ$/MWh by 2025 for most regions – whereas OTA prices were trending to ~150 NZ$/MWh.

Picture in late 2023

- Futures prices in NSW and SA are trending upward, and reach similar level to OTA by cal 2027.
- Prices in VIC and SA regions are flat or falling and much lower than OTA across all years.
- Different price outlooks across NEM regions probably reflects expectations about relative availability of dispatchable resources (hydro, thermal and batteries) among other factors.





Notes
- Prices expressed in nominal $NZ/MWh. Australian prices converted to NZD at prevailing exchange rates.

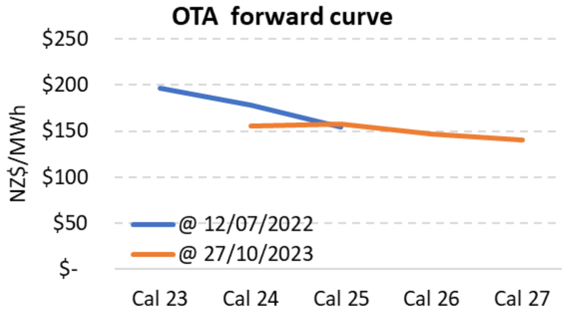
Comparison across regions indicates some variation between NZ and NEM and within each country

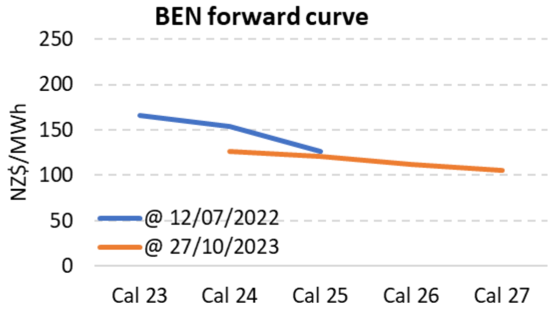
Otahuhu and Benmore

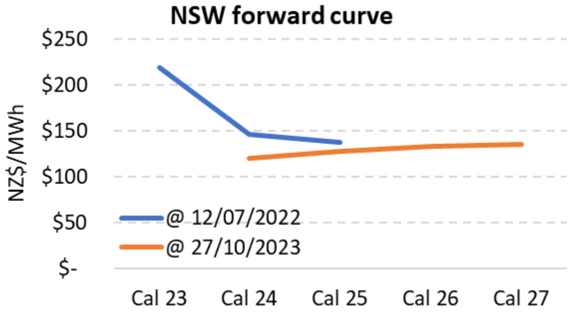
- Prices at Benmore and OTA are trending downward in nominal terms – noting that they are currently much higher than the estimated cost of new supply.
- Futures price at Benmore trends to a much lower level than Otahuhu (~100 $/MWh cf. Otahuhu at ~150 $/MWh).

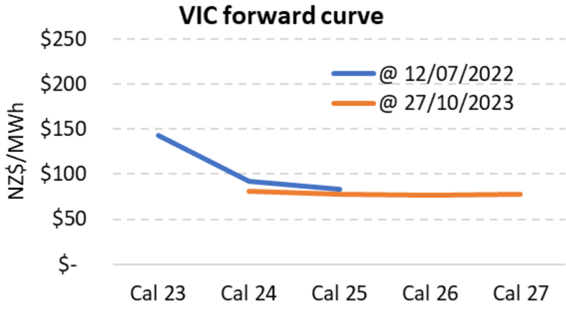
NEM regions

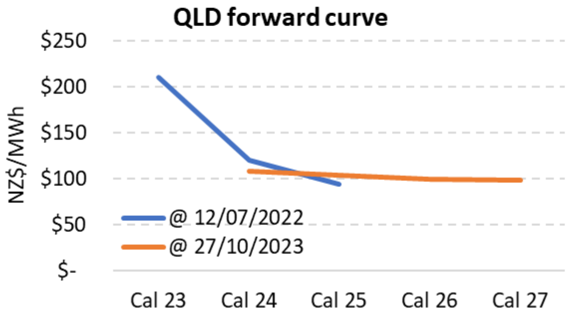
- Price trends vary across NEM regions – with some flat (VIC & QLD) and other rising.
- In NZ and most NEM regions, expectations for cal 2025 prices have remained relatively unchanged.

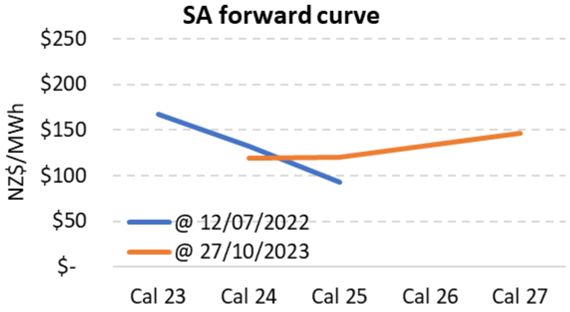












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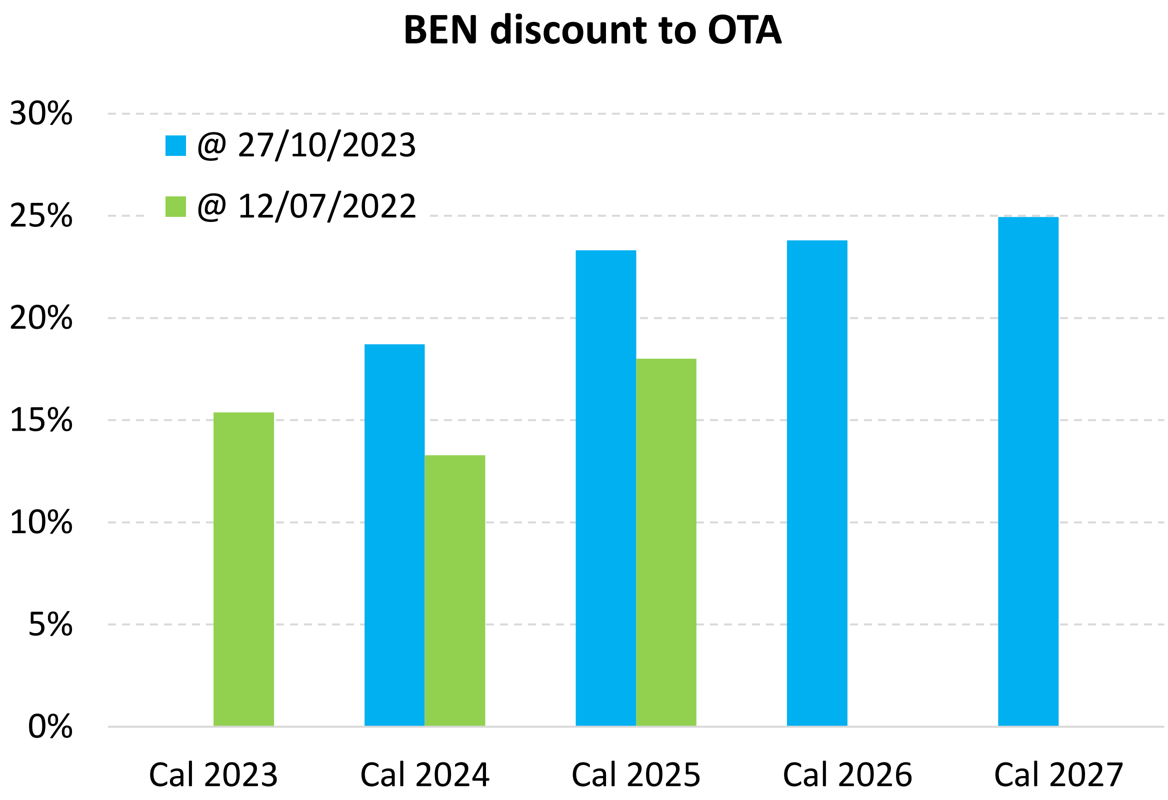
- Contract prices post 2019 are from electricity futures contracts quoted on ASX. They are deflated using CPI, with assumed inflation of 2% for future years.
- Estimated costs for new baseload supply post-2019 are derived by Concept from multiple sources. See earlier slide.

Benmore futures price for Cal 27 appears close to Concept's estimated new supply cost range – whereas the Otahuhu price is well above the range

- Benmore and Otahuhu futures have a declining trajectory to Cal 27 but Benmore falls faster.
- As a result, Benmore discount to Otahuhu grows from 19% in Cal 24 to 25% by Cal 27.
- That discount is around twice the level observed in spot prices in recent years (average = ~13% since 2019) and is also larger than in futures contracts trading in mid-2022.
- Indeed, the Benmore futures price for Cal 27 appears close to Concept's estimated new supply cost range.
- Put another way, futures prices are indicating market conditions will correct faster (still multiple years!) in the South Island than the North Island.
- We think a likely factor causing sticky prices in the North Island is uncertainty about the volume of dispatchable resources (such as thermal, demand response or batteries in the North Island) that will be available later the decade.



LRMC estimates.xlsx

Notes

- ASW futures data showing premium at Otahuhu relative to Benmore. Data downloaded in late October 2027.

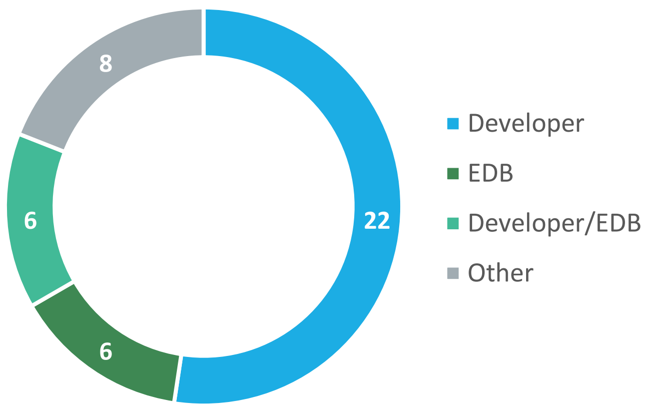
What new renewable generation is committed, and what further potential supply is in the pipeline?

We have extensively engaged with the industry to develop a comprehensive picture of the pipeline of further potential projects

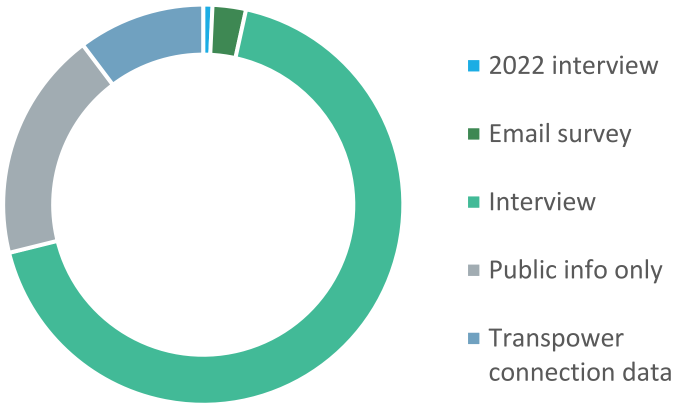
Key points

- Together with Authority staff, we engaged extensively with developers and other parties, via over 40 interviews + email follow-ups.
- Concept would like to record its appreciation for parties' willingness to be interviewed and provide information for this work.
- Where we have been unable to engage with respective developers or the expected scale of a project(s) was not large enough to warrant a specific interview, we have derived data from:
  - public sources (media reports, broker reports, investor presentations, etc.)
  - non-public sources (i.e. previous interviews and Transpower connection data). See slide 16 for more information.

Types of parties interviewed



Source of quantitative data (by output)



Notes

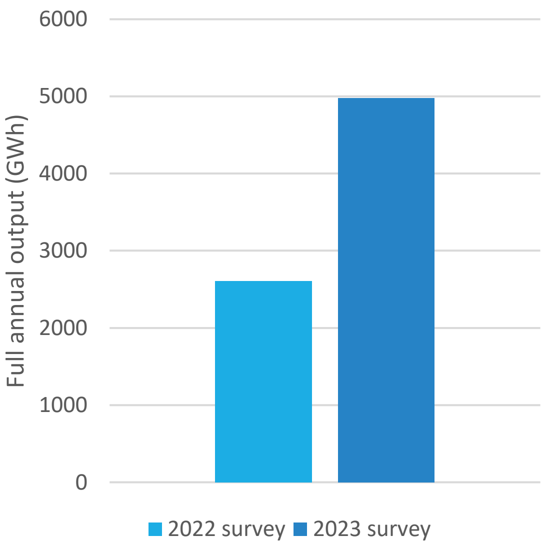
- In processing investment pipeline data from these interviews, we:
  - focused on annual generation output (GWh) rather than capacity (MW). Where only capacity data (MW) was available, we assumed capacity factors to determine generation output data (see Appendix)
  - focused on investments that could realistically be completed by 2027. This is the period covered by the ASX futures contracts. We also considered investments that are likely to be commissioned in 2028 and beyond, but with less focus as these projects are more uncertain and it is likely that as yet unknown projects will emerge that could also be commissioned during this period.
  - included efficiency upgrades to existing plant as new investments for pipeline purposes.
- Depending on their status, potential developments are categorised into one of three groups:
  - Committed projects (i.e. when the unconditional final investment decision has been made. This category should already be baked into the forward curve)
  - Actively pursued projects (i.e. when a site has been identified and the developer has started actively considering at least one of: finance, connection, consents, etc). These are the most relevant projects for the purposes of this investigation, especially those that may be completed by 2027, as they represent projects that have a higher probability of proceeding. Note that the 'actively pursued' category excludes consented projects that appear unlikely to proceed based on current information.
  - Other projects (i.e. projects that are either in very early stages of development or have been put on hold. These projects are unlikely to be built in the next few years, so they are of less relevance to the investment picture in the period 2024-2027. Some of the potential generation in this category may count as "bragga-watts" – i.e. may be unlikely to be built at all).
- In some cases where we could not confirm data with the developer, we estimated or inferred the:
  - project status (based on information available about the stages of the project that have been initiated/completed)
  - expected completion date (based on broker reports, or estimated by considering the type/status of project, other projects being considered by the developer, and Transpower's connection data)
  - connection level (based on Transpower connection data, or in some cases assumed based on the size of the project)
  - type of developer (based on Companies Register searches of the relevant development company).
- Interview and email survey data dated between mid-July and mid-November 2023 (varies by developer). Public data based on most recent sources as at mid-November 2023. Transpower connection data dated 28 August 2023.

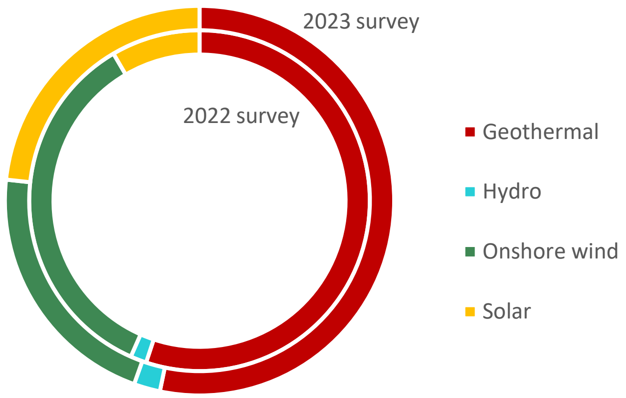
Committed generation has lifted significantly compared to last survey

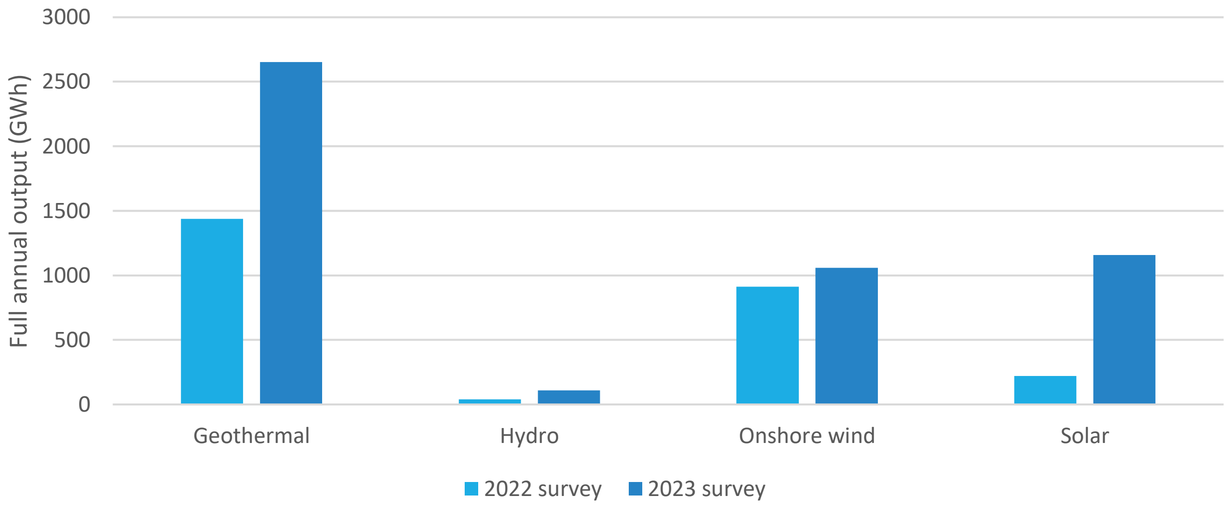
Key points

- There are now committed generation projects with a combined annual output of almost 5,000 GWh, up from around 2,600 GWh in last year's survey.
- Most of the committed generation is expected to be commissioned by 2025. This is because construction tends to begin shortly after a project is committed and lead times do not tend to stretch beyond several years.
- Most of the new committed generation since last year's survey comes from geothermal and solar projects.

Committed projects







Notes

- Includes committed projects for 2023 that have since been commissioned, but excludes projects completed prior to 1 January 2023.
- Assumed capacity factors are geothermal (95%), hydro (50%), onshore wind (40%) and solar (20%).

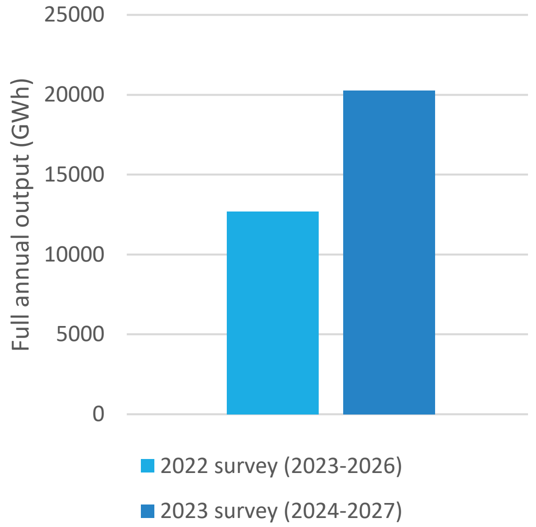
Actively pursued generation has also lifted significantly compared to last survey

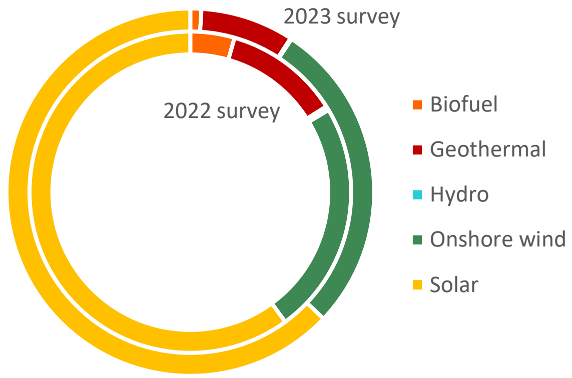
concept consulting

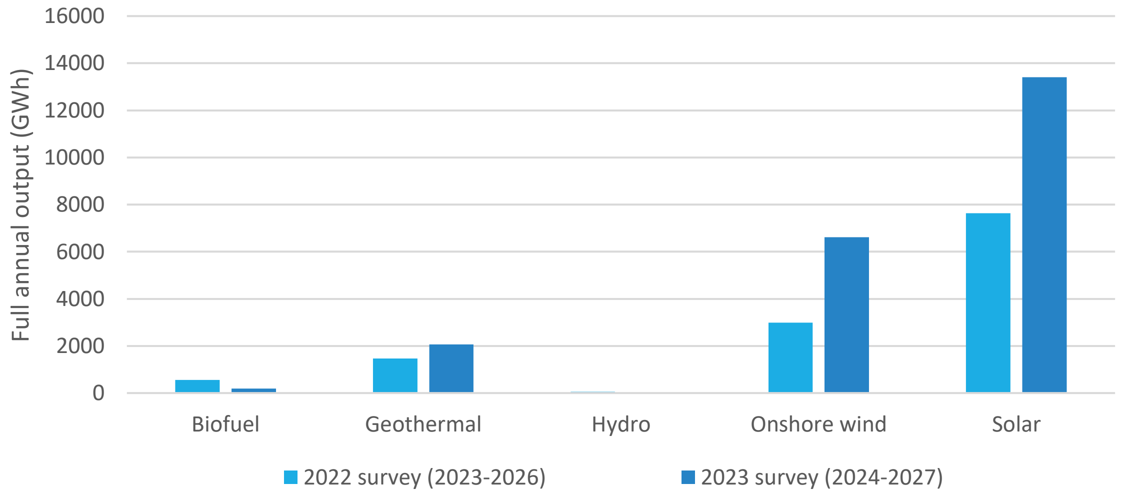
Key points

- There are now actively pursued projects with a combined annual output of over 20,000 GWh that could potentially be completed over the next four calendar years, up from almost 13,000 GWh in last year's survey.
- This increase is mostly a result of more actively pursued solar, geothermal and wind projects.
- There has been little change in the relative proportion of generation types. As a result, solar projects still dominate the pipeline of actively pursued projects.
- Actively pursued projects that could be completed after 2027 have a combined annual output of over 38,000 GWh. About three quarters of these projects (by output) are offshore wind.

Uncommitted but actively pursued projects







Notes

- Figures based on GWh/yr for actively pursued projects with an expected completion date of 2023-2026 (for last year's survey) and 2024-2027 (for this year's survey).
- Assumed capacity factors are biofuel (60%), geothermal (95%), hydro (50%), onshore wind (40%) and solar (20%).
- One uncertain biofuel project has been downgraded from "actively pursued" to "other" resulting in a decrease in this category.

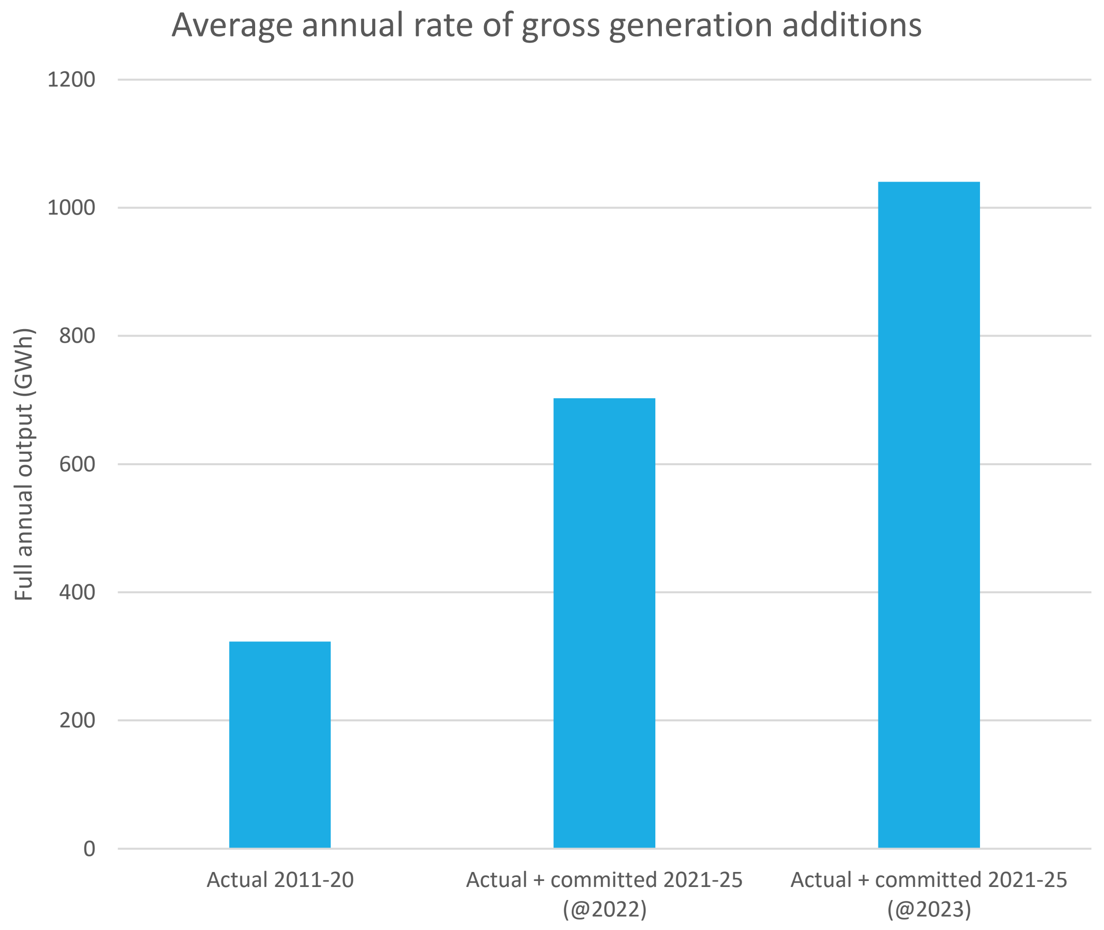
The generation development pace has lifted significantly compared to the previous decade

Historical rate of additions

- In the decade to 2020, the average annual gross new generation produced an additional 320 GWh/yr.

Projected additions for 2021-25

- Average annual actual + committed generation additions were running at around 703 GWh/yr based on 2022 survey.
- This rate has lifted further in recent survey to an annual addition of 1040 GWh/yr of actual and committed generation.



Notes

- Capacity additions for 2025 assume project is commissioned in mid-year (i.e. 50% derating for that year)

Our pipeline appears to show more committed generation than public sources - implying that public domain information is not necessarily reliable

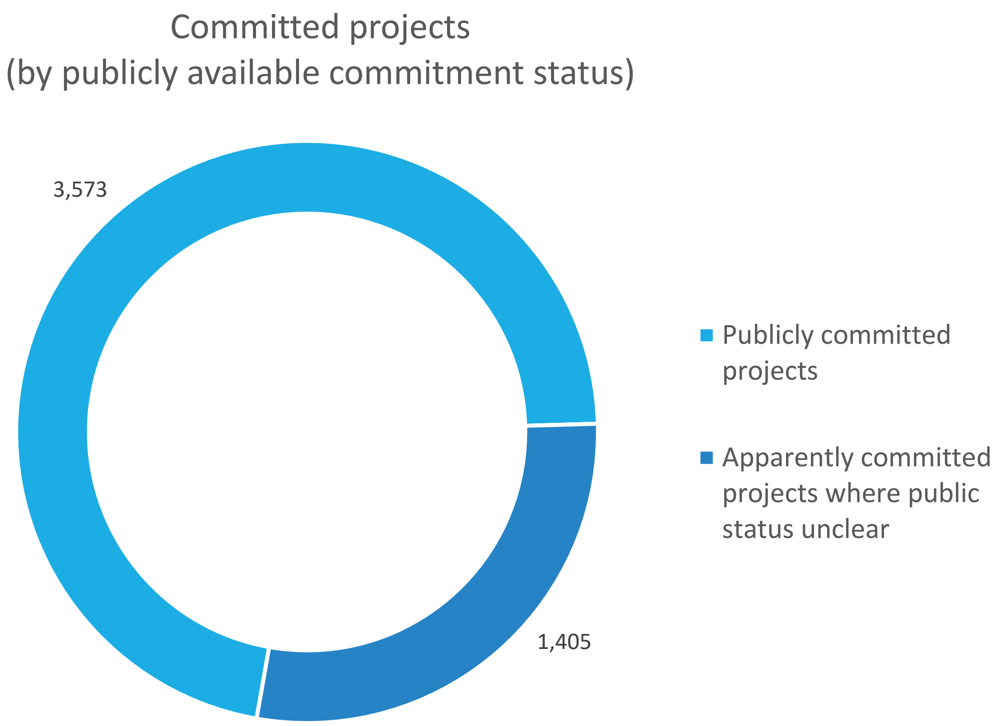
Key points

- Based on confidential survey data we assess there are new projects with a combined annual output of around 1,400 GWh that have been committed for development (or are under construction), but whose commitment status is not necessarily clear from public data. This group accounts for about 28% of total committed projects.

- Differences between the survey-based assessment and the public data-based assessment can arise because:
  - A few developers/projects appear to make no public disclosures
  - Some developers/projects do not regularly update their public disclosures
  - Some developers/projects have disclosures that are incomplete or contradictory making it hard to definitively assess project status from public data

- The ambiguous status of some projects reflects the changing demographic of generation developers. When generation was largely being built by the major listed companies, NZX disclosure rules resulted in up-to-date information being regularly communicated to the market. However, a growing number of independent developers are not NZX-listed and therefore information is less comprehensive. Transpower connection queue data provides some public information but does not necessarily reveal the prevailing status of generation projects in the queue.

- Finally, it is important to bear in mind that some of the 1,400 GWh of projects we classify as committed may not yet proceed. We defined 'committed' as where the sponsor informed us that an unconditional final investment decision has been made (i.e. not conditional on any consents, finance, connection, etc). Despite this categorisation, it is possible that a developer may later suspend its development decision after FID is made or that they incorrectly communicated that a project was committed (i.e. if they had a different understanding of the point at which a project reaches FID).



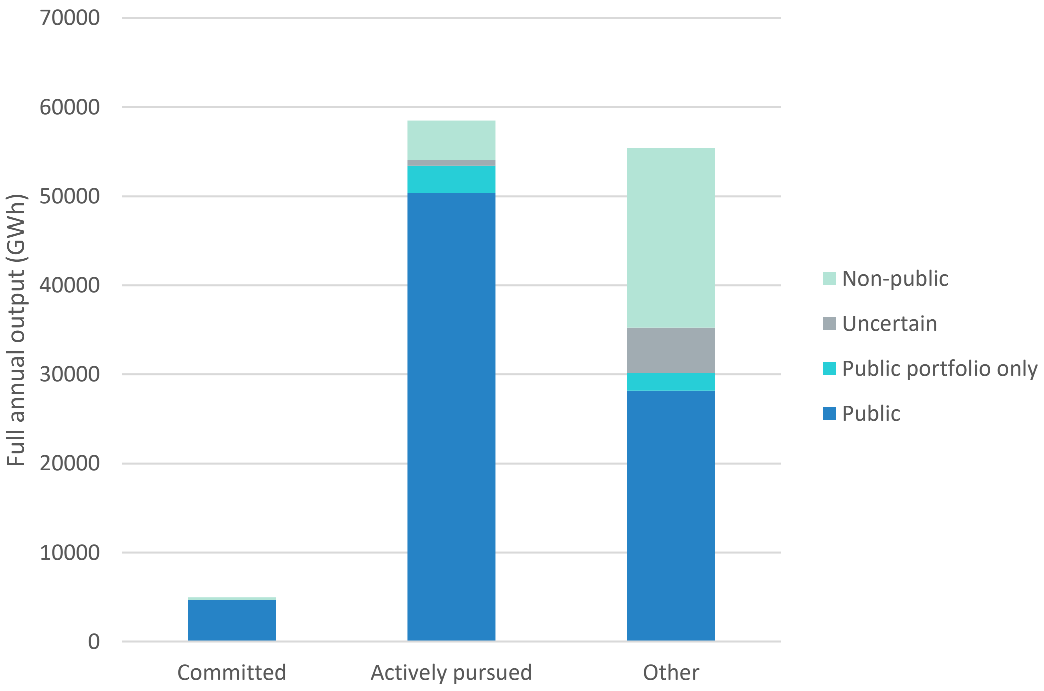
Notes

- Figures based on GWh/yr for all years. Assumed capacity factors are geothermal (95%), hydro (50%), onshore wind (40%) and solar (20%).
- Publicly available commitment status based on information available as at mid-November 2023.
- Public projects are those where there is clear information in the public domain that the project is fully committed. Uncertain projects may still have public information about the project proceeding, but where there is some ambiguity as to whether the project is fully unconditional.

There is more total potential generation in the development pipeline than is apparent from public sources

Key points

- The pipeline of potential new developments is large. Across all years, it contains:
  - ‘actively pursued’ projects (see definition on previous slide) with potential to produce an annual output of ~59,000 GWh
  - ‘other’ projects with potential to produce an annual output of ~55,000 GWh.
- Obviously not all of these projects, particularly those in the ‘other’ category, will be built for technical or commercial reasons, and many could not be built until later in the decade).
- Some of the development pipeline is not in the public domain, particularly less mature projects. Some developers fly below the radar, and some developers with a public profile are working on projects not yet in the public domain. Around 74% of projects (based on aggregate output from committed, actively pursued and other projects across all years) we were also able to find in the public domain.



Notes

- Figures based on GWh/yr for all years. Assumed capacity factors are biofuel (60%), gas (15%), geothermal (95%), hydro (50%), offshore wind (55%), onshore wind (40%) and solar (20%).
- The majority of projects from developers that were not interviewed came from Transpower’s connection enquiry data. Transpower’s connection enquiry data has almost 70,000 GWh/yr of project enquiries, but many of these projects were not added to our development pipeline because they are:
  - already in our dataset (i.e. from our interviews, publicly available information, etc.)
  - already commissioned
  - from lines companies without specifying the actual developer (to avoid double counting, we only included projects applied for by lines companies where we were not aware of any other similar projects in the area)
  - categorised by Transpower as
    - “unlikely” to proceed (i.e. <5% likelihood) and at any stage of the application process
    - “uncertain” to proceed (i.e. 25% likelihood) and only at the “prospect” or “initial enquiry” stage of the application process
- We categorise included projects from Transpower’s data as follows:
  - Projects that are in the Transpower connection queue (i.e. at the “application confirmed” or “investigation” stage) are assumed to be “actively pursued” and have an expected completion date of 2025 (solar), 2026 (storage), or 2027 (onshore wind)
  - Projects that are not in the Transpower connection queue but have a “possible”, “likely” or “highly likely” (i.e. >50%) likelihood of proceeding are assumed to be “other” and have an expected completion date of 2026 (solar), 2027 (storage) or 2028 (onshore wind)
  - Projects that are not in the Transpower connection queue and have an “uncertain” (i.e. 25%) likelihood of proceeding and are at the concept assessment stage are assumed to be “other” and have an expected completion date of 2027 (solar), 2028 (storage) or 2029 (onshore wind)
  - All offshore wind projects are assumed to have an expected completion date of 2030+.

There is a substantial pipeline of active projects that could be available by 2027 (predominantly solar) and even more opportunities in 2028 and beyond

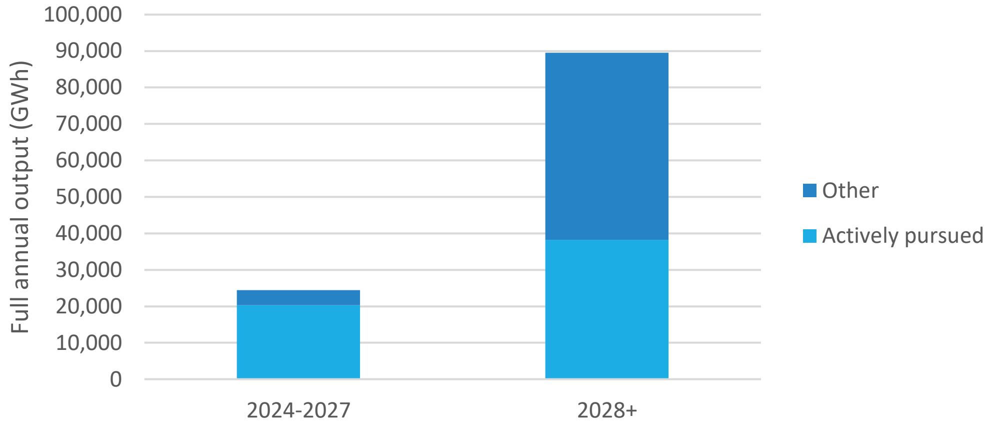
Key points

- We estimate that there are actively pursued projects with an annual output of over 20,000 GWh that could feasibly be completed by 2027.
- Much of the development pipeline is still some years away. A larger proportion of actively pursued generation (with annual output totalling over 38,000 GWh) could only be feasibly completed in 2028 and beyond.
- Much of the development pipeline is uncertain. There are 'other' potential generation projects in the development pipeline with annual output totalling over 55,000 GWh, although these projects are all either speculative or on hold. Few of these projects would be able to be completed by 2027 even if they were actively pursued.
- In the near term, solar development is likely to be particularly relevant. 63% of actively pursued projects (by output) that could be completed by 2027 are solar projects, a large proportion of which are in the hands of international developers.

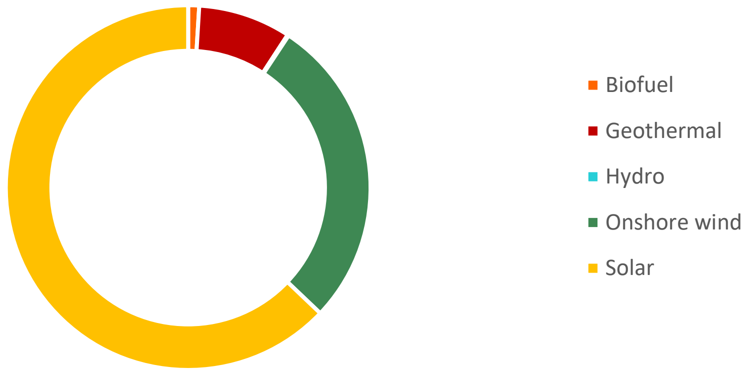
Development pipeline (GWh/yr)

	2023	2024	2025	2026	2027	2028+	Total
Committed	605	3,029	1,286	58			**4,979**
Actively pursued		226	6,841	6,853	6,359	38,239	**58,518**
Other			238	818	3,075	51,305	**55,436**
Total	**605**	**3,255**	**8,366**	**7,730**	**9,434**	**89,544**	**118,933**

Non-committed projects by completion date



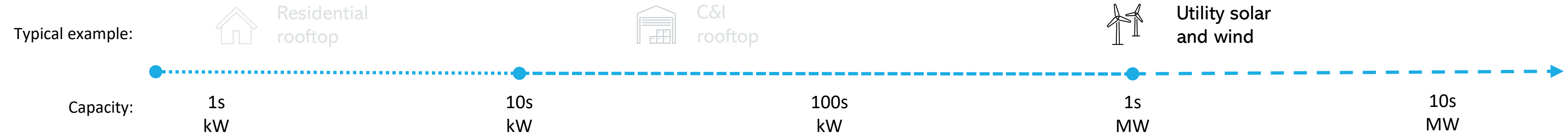
Active projects by fuel type



Notes

- Figures based on GWh/yr. Assumed capacity factors are biofuel (60%), gas (15%), geothermal (95%), hydro (50%), offshore wind (55%), onshore wind (40%) and solar (20%).
- Active projects pie chart refers to actively pursued projects that could be completed by 2027.
- Our expected completion date is the earliest feasible calendar year in which generation is expected to begin, assuming the development timeline goes to plan. In reality, there are likely to be delays that push some projects further back.

There has been surge in utility-scale DG activity



Utility-scale (1MW or more)

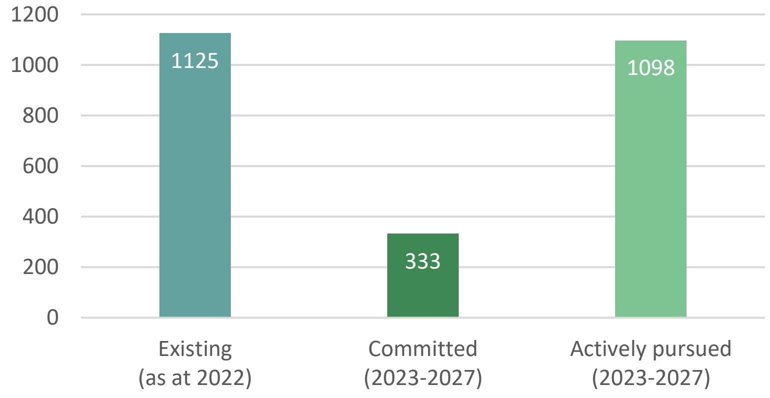
1. There has been a surge in utility-scale solar DG development activity over the past 12-18 months (and some wind). If all committed and actively pursued utility-scale DG projects are built, they will more than double the capacity of existing utility-scale DG on the system by 2027. The first projects are beginning production now.

2. The surge has driven sharp learning curves and resourcing constraints for impacted distributors, contributing to extended lead times. Engineering and commercial processes are more complex and iterative than smaller-scale DG and introduce technical challenges that are unique to utility-scale generation.

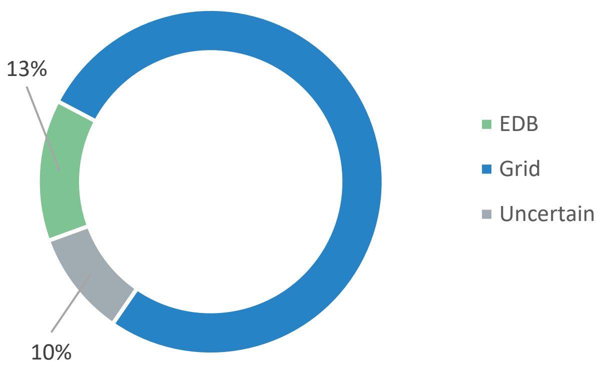
3. Available network capacity has been a key project filter. Projects that are advancing are typically smaller, shallow (near a GXP) or in areas with surplus network capacity. The surge may run out of steam as network capacity is used up, because the next wave of projects will be more challenging.

4. Utility-scale DG makes up at least 13% of the estimated pipeline of actively pursued projects that could be completed by 2027 (on an energy production basis). The connection status of a further 10% of projects is uncertain, but some of this may also be distribution-connected.

1 Utility-scale distributed generation (MW)



4 Active projects (GWh/yr)



Notes

- "Existing" utility-scale DG includes DG reported in EMI for 31 December 2022 across wind, natural gas, geothermal, fresh water and biomass fuel types – i.e. excluding fuel-types that have typically been small-scale (such as solar and diesel) or embedded with load (such as industrial heat). Also excludes "other".
- "Committed" and "actively pursued" includes only identified utility-scale DG projects that could be operating by 2027.
- The pipeline of actively pursued EDB-connected projects (i.e. DG) to 2027 could contribute 1,098 MW and almost 2,700 GWh/yr once fully developed. This represents 13% of the total identified pipeline.
- Assumed capacity factors are biofuel (60%), geothermal (95%), hydro (50%), onshore wind (40%) and solar (20%).

Mid-scale solar DG has been accelerating quickly from a modest base

Typical example: Residential rooftop | C&I rooftop | Utility solar and wind

Capacity: 1s kW | 10s kW | 100s kW | 1s MW | 10s MW

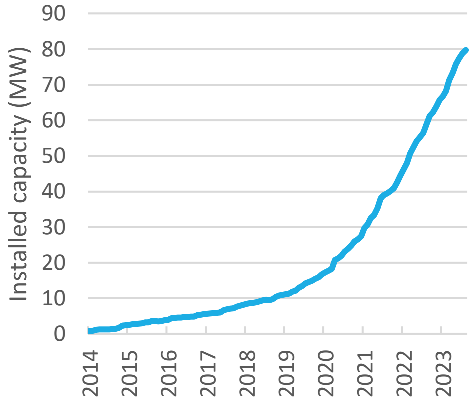
Medium (10kW to 100s kW)

1. Mid-scale DG activity is dominated by solar, which comprises around 75% of DG >10kW (by ICP count).

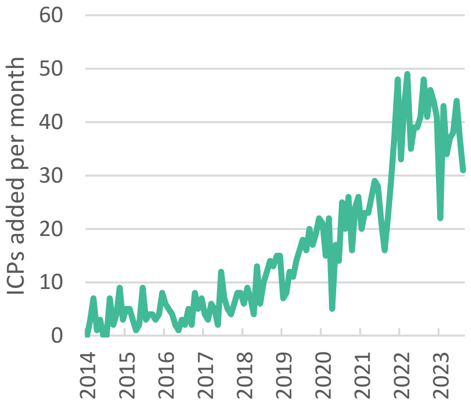
2. Although mid-scale solar projects are more expensive ($ per kW) than utility-scale:
   - they are typically easy to develop. There are competing suppliers, network hosting capacity is typically not a problem, and the network access arrangements (Part 6) are relatively straightforward and working well
   - users have a range of motivations for installing systems, including green credentials, resilience and reducing exposure to electricity price movements.

3. Installed solar capacity (MW) is growing rapidly, albeit from a low base. If 50% year-on-year growth rate persists, then mid-scale solar could add nearly 20% to the actively pursued pipeline of identified utility-scale DG projects for 2023-2027.

Mid-size solar growing rapidly…



…due to accelerating pace.

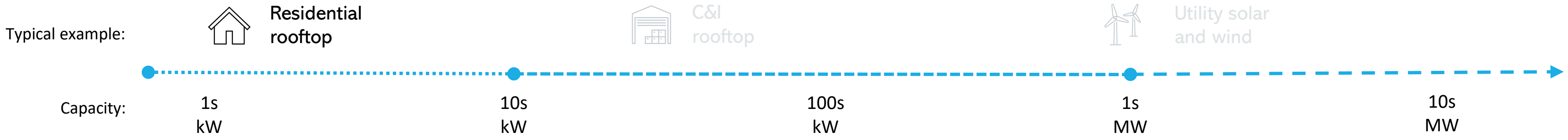


If assume 2014 to 2022 CAGR of 50% continues:

	2023	2024	2025	2026	2027	2023-2027
New mid-scale solar (GWh p.a.)	40	60	91	136	204	530
Compared to pipeline of identified DG projects (%)						+20%

Notes
- ICP figures sourced from EMI. Records do not break out mid-scale DG from utility-scale, but we assume very few existing solar ICPs that are >10kW are utility-scale. Solar is less than 5% of DG >10kW by capacity, but non-solar DG includes many multi-MW installations.
- Assumes capacity factor of 15%. Headwinds or tailwinds may drive material departure from this simple projection.
- "Pipeline of identified DG projects" refers to all actively pursued utility-scale DG projects that could be completed by 2027, which have a cumulative annual output of 2,692 GWh.

Small-scale DG growth accelerating from modest base



Small (10kW or less)

1. Dominated by residential rooftop solar, with MW per month growing as:
   - average installation size has increased
   - installation rate (new ICPs per month) trending up

2. More expensive ($ per kW) than larger systems, but easy to develop – competing suppliers, network hosting capacity usually okay, and Part 6 process working well

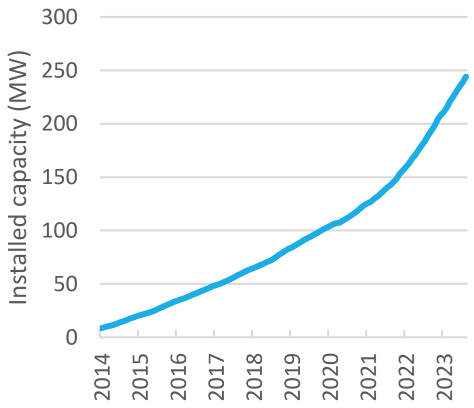
3. Headwinds:
   - more cost-reflective tariffs (lower daytime rates)
   - some LV networks approaching hosting limit

4. Tailwinds:
   - energy price
   - green loans from major banks
   - higher penetration (market momentum)
   - resilience benefits of solar + battery

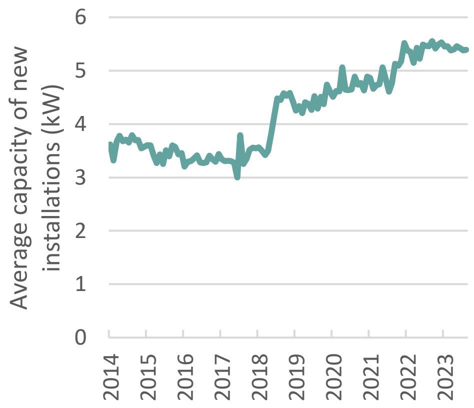
5. If sizing stabilises at 5.5kW and linear installation rate growth continues, then small-scale solar could add nearly 20% to the actively pursued pipeline of identified utility-scale DG projects for 2023-2027.

6. If small- and mid-scale DG projections are included, they make up 4% of the total 2023-2027 pipeline (i.e. all connection types).

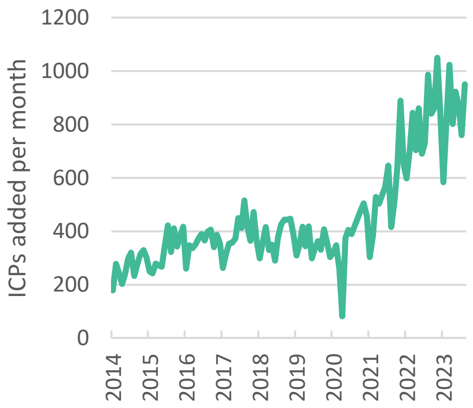
Small solar growing rapidly…



…due to larger systems…



…and accelerating pace.



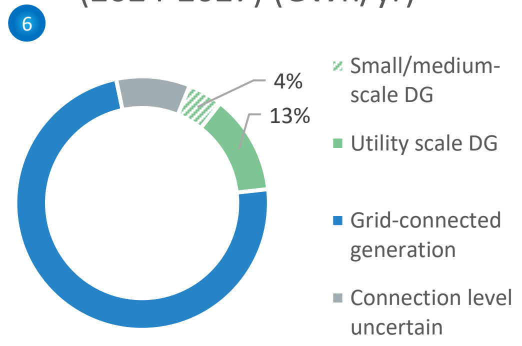
If we assume average size stabilises at 5.5kW and volume follows a linear growth trend:

	2023	2024	2025	2026	2027	2024-2027
New small-scale solar (GWh p.a.)	73	92	106	121	136	527
Compared to pipeline of identified DG projects (%)						+20%

Notes

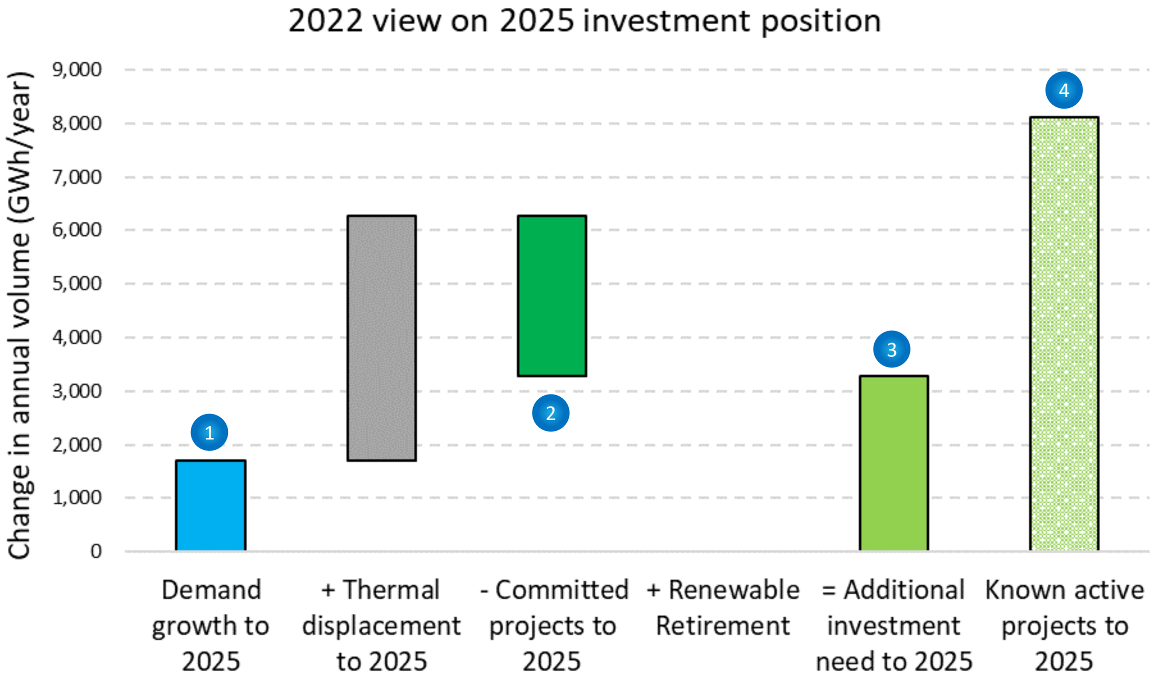
- Assumes capacity factor of 14%. Headwinds or tailwinds may drive material departure from these simple projections.
- We have included the fuel type 'other' in total capacity and ICP count (as this appears to be mostly solar and battery systems). For average capacity per installation, we have used 'solar' fuel type only.
- "Pipeline of identified DG projects" refers to all actively pursued utility-scale projects that could be completed by 2027. This figure is 2,692 GWh/yr.

Actively pursued projects (2024-2027) (GWh/yr)

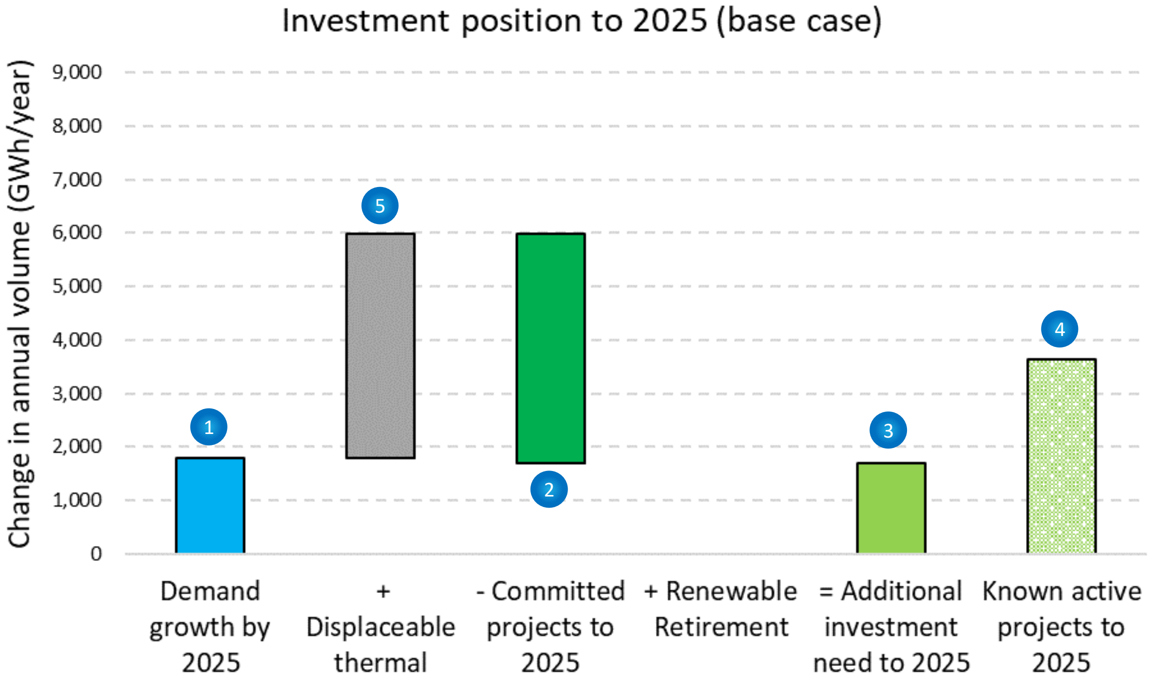


How much additional generation is needed, and how does this compare to the pipeline?

Our view on 2025 has evolved significantly from last year



investment analysis.xlsx



investment analysis.xlsx

Key points

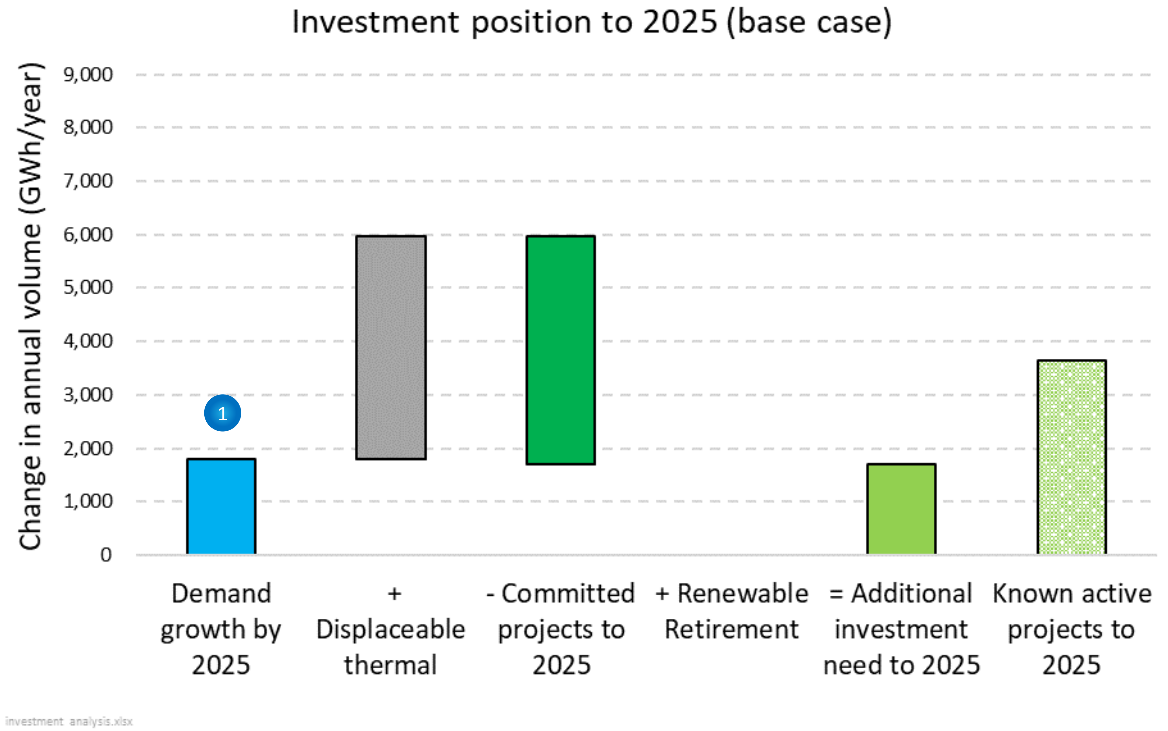
We are one year closer to 2025 compared to our report last year. In that time the outlook for 2025 has progressed:

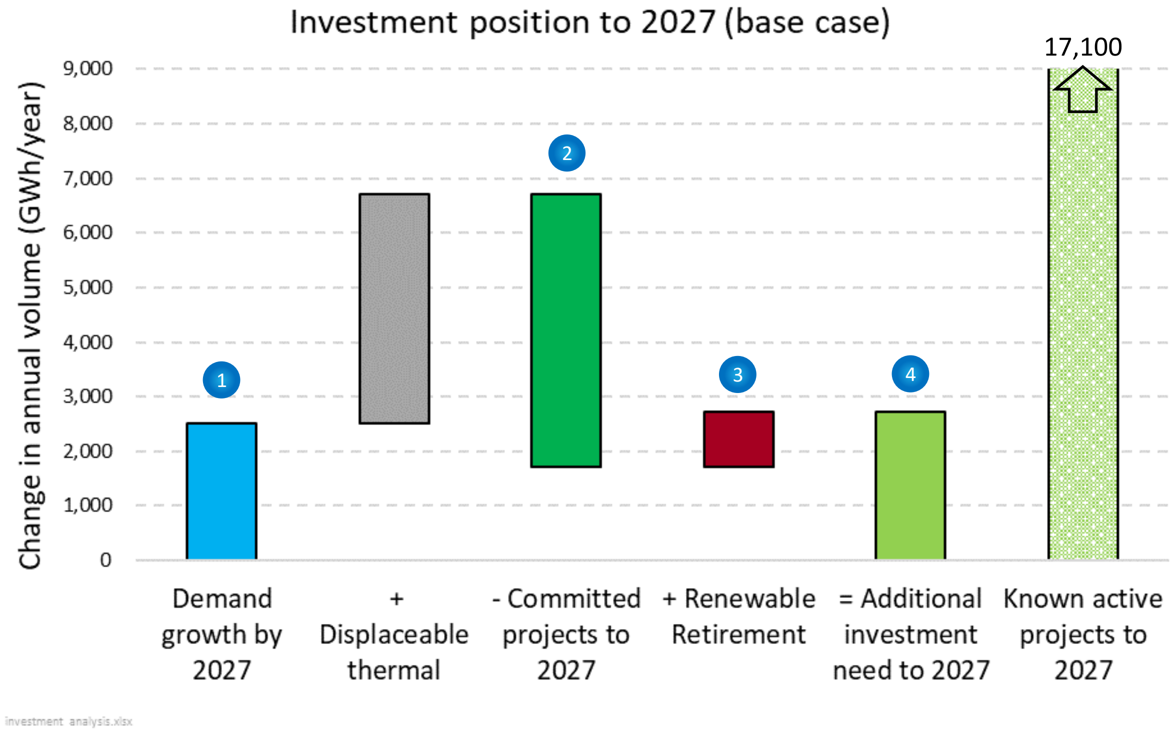
1. Demand growth projections to 2025 have not changed appreciably and the thermal displacement opportunity has reduced modestly – reflecting lower forward prices for carbon and fuel than in the previous report.
2. Committed projects have grown significantly as discussed earlier.
3. Together these factors shrink the projected additional generation requirement for 2025 from an annual output of around 3,300 GWh to 1,700 GWh.
4. Non-committed but active projects that could meet this need have a combined annual output of 3,600 GWh – i.e. more than a 2x cover ratio. This is less than last year's report but is not surprising because the status of active projects becomes clearer as we draw closer to 2025 (i.e. they become committed, or unavailable for commissioning by that year).
5. A key change from the last report is that committed generation is now similar to the estimated thermal displacement opportunity – in effect **this means further generation investments will be to meet demand growth - making demand expectations more critical.**

Notes

- Our analysis compares the relative economics of different types of generation at different capacity factors. While this is not a complete system model and focusses on energy requirements, we believe this is a reasonable approach, and note that other more detailed modelling typically comes to similar conclusions on thermal utilization.
- Demand growth projection is the reference scenario from Transpower's Net Zero Grid Project 1.
- Thermal displacement is volume of fossil fuel generation (ex cogen) that is estimated to be economic to displace based on forecast carbon and fuel prices in 2025 and projected cost of new renewable supply (assumed to be 90 $/MWh on a firmed basis).
- Known 'active' projects to 2025 are those for which work is underway on consents, offtake and/or connection arrangements.
- Unless there is reason to assume otherwise, we assume that projects are commissioned halfway through the year, so projects only contribute 50% of their output in their first year.

We have extended our analysis to 2027, but the picture is similar to 2025





Key points

1. In the base case we project annual demand to be 2,500 GWh by 2027 (700 GWh more than by 2025).
2. Committed projects coming on stream by 2027 add almost 5,000 GWh to annual output (700 GWh more than by 2025).
3. The planned retirement of Wairakei will reduce annual output by around 1000 GWh.
4. Together these factors mean the projected investment need for 2027 is an annual output of around 2,700 GWh (1,000 GWh more than by 2025).
5. However, actively pursued projects that could meet this need equate to an annual output of more than 17,000 GWh.

Notes

- We have assumed the same thermal displacement value in 2027 as for 2025 on the basis that renewable investment decisions are likely to reflect system conditions over multiple years.

Projected additional investment need for 2027 is sensitive to certain factors – especially the future operation of the Tiwai smelter

Key points

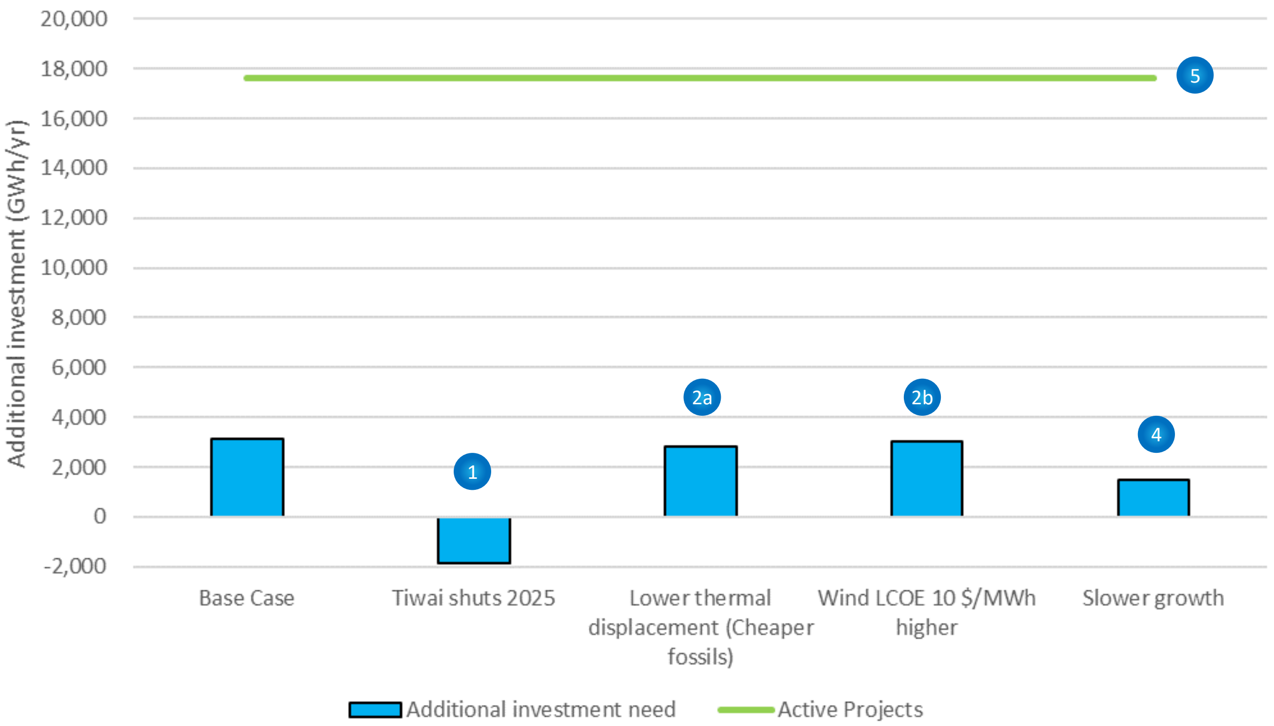
1. Additional investment requirement is very sensitive to Tiwai smelter demand. The base case assumes Tiwai smelter continues to operate post 2024. If closure were to occur, there would be no need for further investment prior to 2027.

2. We included two scenarios with fossil fuels cheaper relative to renewables. These were:
   a) Lower thermal displacement (i.e. fuel prices 66% of our base case)
   b) More expensive renewables (i.e. wind LCOE 10 $/MWh higher).

3. Neither of these scenarios had a significant effect on the quantity of new generation required. This is because our base case continues to utilize most of the CCGT and OCGT capacity available until 2027. Even if thermal is more attractive to operate, there is limited additional capacity available.

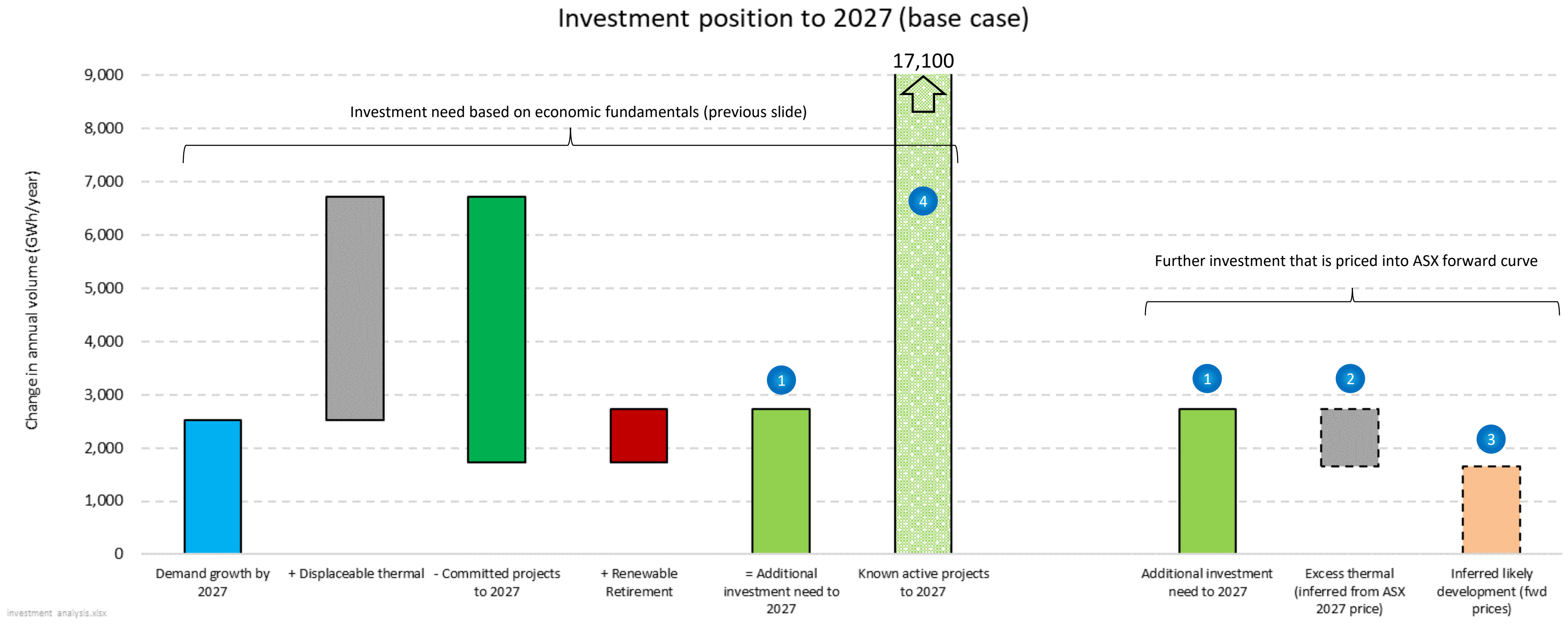
4. Slower demand growth would reduce the need for new investment. Our sensitivity uses demand growth assumptions which result in about 1,500 GWh less demand in 2027 than our base case.

5. The potential generation from active projects is well in excess of all our sensitivities.



Notes
- Tiwai shuts case assumes smelter closure from January 2025.
- Lower thermal displacement case uses lower thermal fuel costs of 66% of the base case.
- Wind LCOE $10/MWh higher case assumes wind is around $100/MWh after firming (compared to around $90/MWh in the base case).
- Slower growth case is by assumption and assumes a lower rate of growth resulting in 1,500 GWh/yr less demand by 2027.

ASX prices can be used to infer how much renewable investment is not expected to be committed



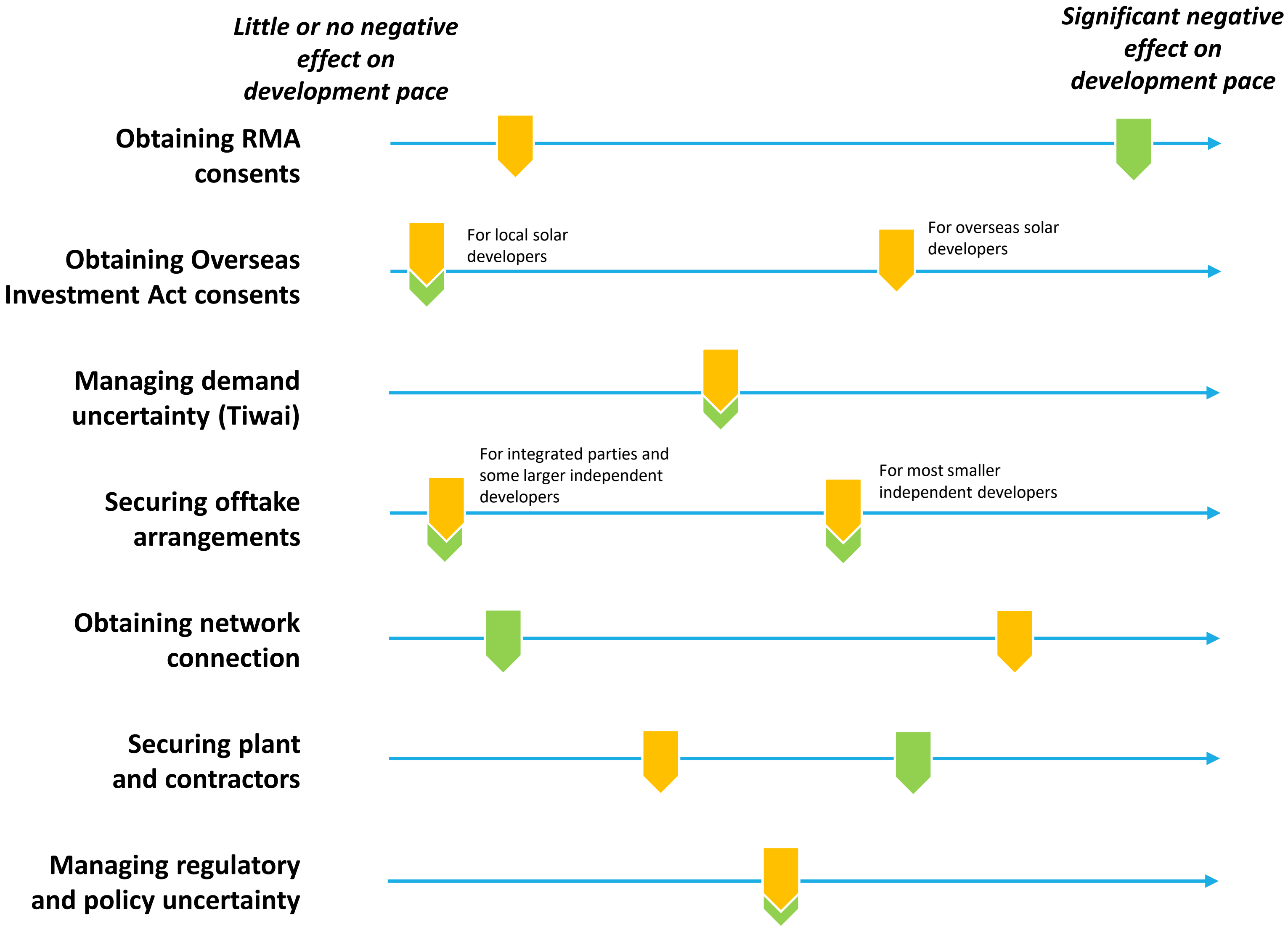
Key points

The previous slide shows estimated economic “need” for additional investment by 2027. We can estimate how much of this required generation is priced into the ASX futures curve. A higher-than-equilibrium ASX price indicates thermal generation is expected to continue to run even when it would be economic to replace it with renewable generation.

1. We estimate that additional annual output of 2,700 GWh of generation would be optimal by 2027.
2. The price uplift in the ASX futures curve suggests that in 2027 NZ will run around 1,100 GWh of thermal generation in excess of the amount expected in equilibrium.
3. The difference between the two suggests that the ASX futures market infers that generation with an annual output of ~1,600 GWh will be built by 2027.
4. The active projects for 2027 have an annual output totalling over 17,000 GWh.

What are the key factors affecting the pace of generation development?

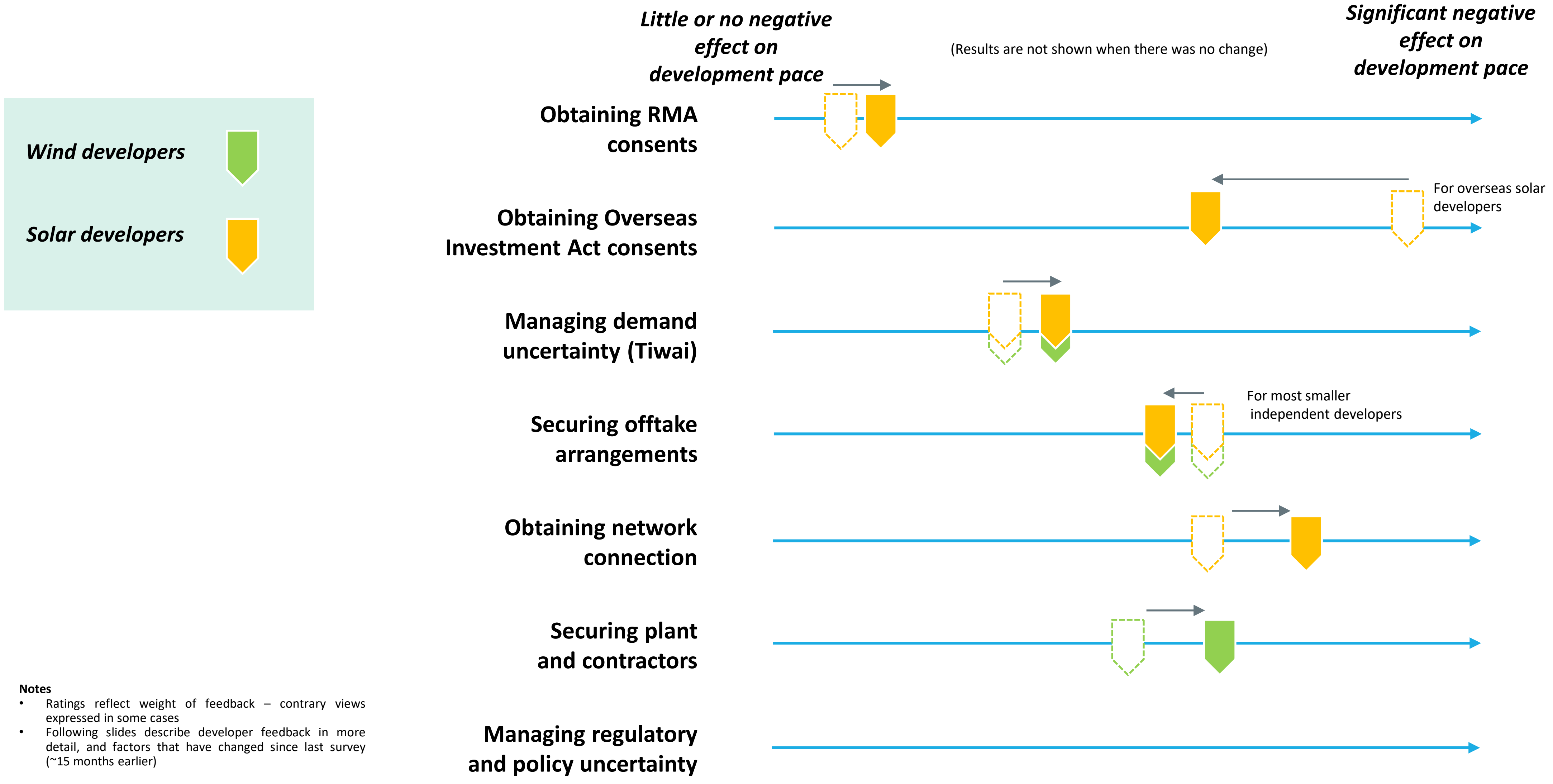
Most developers see overall environment as attractive, but cite following as main factors affecting development pace



Notes

- Ratings are based on interview responses and reflect broad themes. Contrary views were expressed in some cases.
- Ratings only shown for solar and wind developers because there were too few responses to assess views for other types.

Compared to previous survey, sentiment changed appreciably in the following areas…



Notes
- Ratings reflect weight of feedback – contrary views expressed in some cases
- Following slides describe developer feedback in more detail, and factors that have changed since last survey (~15 months earlier)

Environmental consenting processes remain a critical factor affecting the generation pipeline and development rate

Consenting continues to strongly influence development rates

- Wind and geothermal projects take years to progress (absent fast-track option).
- Hydro consenting perceived as too difficult to pursue by most parties.
- Solar faster to consent where local planning documents allow for it – elsewhere there is some uncertainty over timeframes.

Developers noted some positive changes…

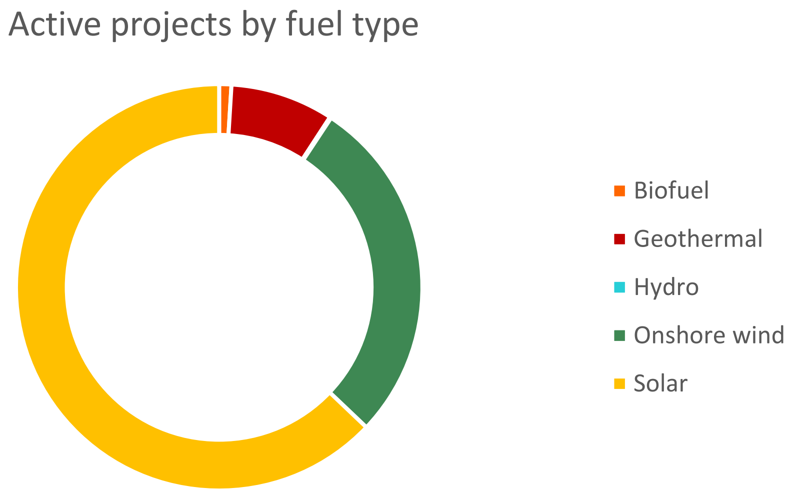
- Most Councils getting more familiar and comfortable with solar projects.
- Greater comfort with use of the RMA's fast-track option (see next slide).

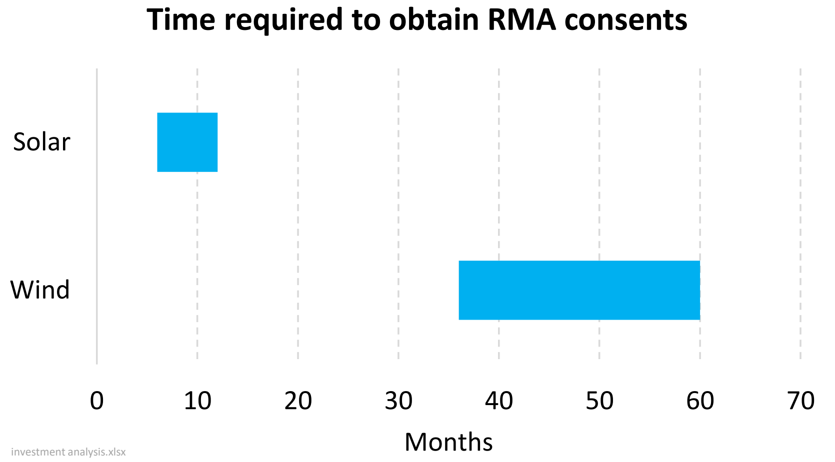
And some new factors that could affect the pace of development

- National Policy Statement (NPS) on Highly Productive Land (HPL) issued in September 2022 cited as having unintended negative effects by many solar developers. MfE is currently considering amending the NPS to provide a clearer pathway for construction of new specified infrastructure (including solar farms) on HPL.
- Stormwater and soil contamination raised as potential issues for solar by some consenting authorities.
- Natural and Built Environment Act (RMA replacement) was widely seen as likely to create new uncertainty for developments despite previous Government's stated intentions – at least in the bedding-down period for the new legislation.

Overall comment

- Obtaining consents remains time consuming – especially for wind projects. This is underscored by comments (unprompted) from two international developers that NZ's consenting processes are the most complex they have encountered.

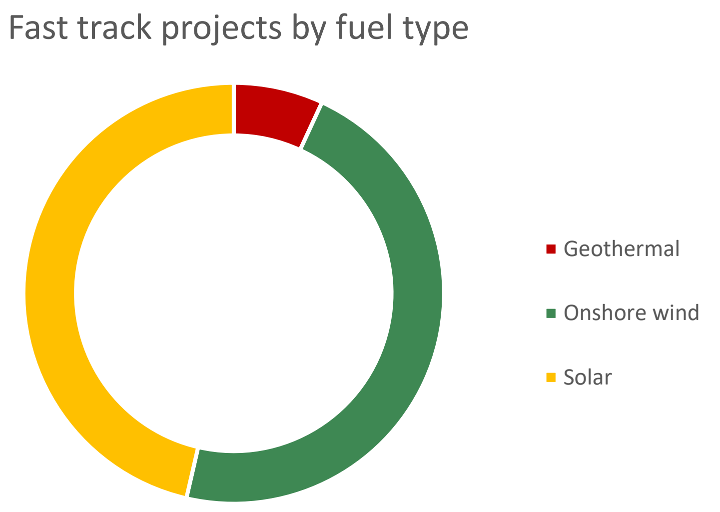


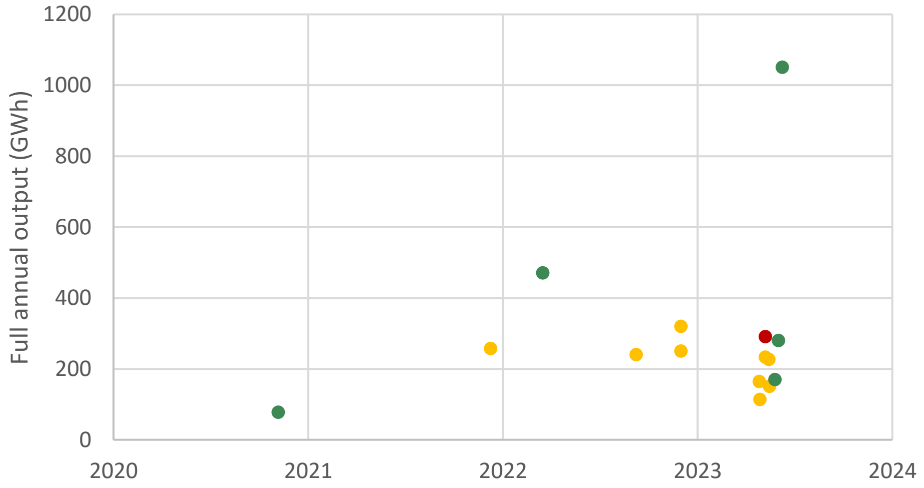


Notes
- Based on interviews with developers and other sources.
- Percentages based on GWh/yr for actively pursued projects that could be developed by 2027.
- Assumed capacity factors are biofuel (60%), geothermal (95%), hydro (50%), onshore wind (40%) and solar (20%).

There has been greater uptake of the RMA fast track option in the last 12 months – that window is now closed, but the new NBEA potentiallv offers a similar alternative pathway

- The COVID-19 Recovery (Fast-track Consenting) Act 2020 introduced an alternative pathway for consenting. The process differs from standard consenting under the RMA in several ways, including:
  - Decision maker – the application is considered by an expert panel, rather than a local authority
  - Public notification – there is no requirement for public/limited notification (however, the panel must invite written comments from some people/groups listed in the Act)
  - Timeframe – a decision on referred projects must be issued within 45 working days (70 working days if the timeframe is extended)
  - Appeal rights – decisions may be appealed to the High Court within 15 working days of notification of the decision. Only certain persons listed in the act may appeal the decision, and only on questions of law (not on the merits of the decision).
- The Act was repealed on 8 July 2023, but the process remains in effect for projects that were referred to the expert panel before this date. 15 electricity generation project applications have been referred for fast-tracking, most of which were made in the second quarter of 2023 – i.e. just before the cut-off.
- Most projects referred for fast-tracking are solar, although they make up just under half the expected output in GWh/yr. There are also several onshore wind projects and one geothermal project.
- The new Natural and Built Environments Act 2023 includes a similar fast-track framework, although no projects have yet been referred under this Act. The new framework has some key differences, including longer timeframes than the COVID-19 Recovery (Fast-track Consenting) Act 2020.





Notes

- Figures based on GWh, derived from MW figures for projects referred for fast-tracking under the COVID-19 Recovery (Fast-track Consenting) Act 2020. Assumed capacity factors are geothermal (95%), onshore wind (40%) and solar (20%).
- Information regarding fast-track consenting process can be found at https://environment.govt.nz/acts-and-regulations/acts/covid-19-recovery-act-2020/ and https://environment.govt.nz/assets/publications/RM-system-2023/Fast-track-consenting-process.pdf

Concerns about application of Overseas Investment Act regime have substantially reduced, although costs and timeframes remain a concern for some developers

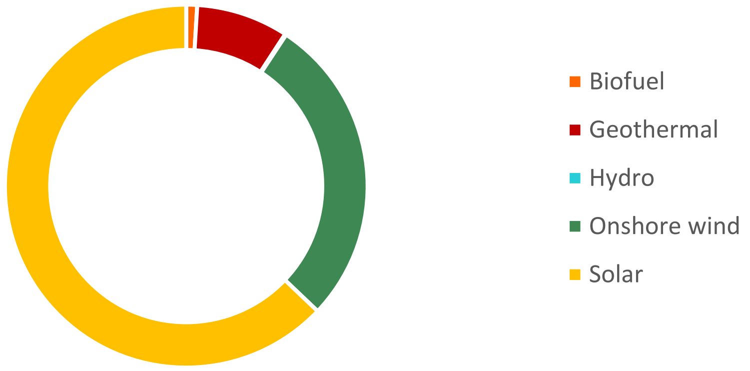
Previous position

- Our last survey found Overseas Investment Act (OIA) requirements were the number one concern of some large solar developers because:
  - Solar projects typically require land to be leased or bought (unlike wind projects, which can potentially use easements), which triggers the requirement for consent under the OIA
  - It was unclear how/whether some provisions would apply (particularly regarding exemptions from the obligation to advertise farm land on the open market prior to selling/leasing it to an overseas party).
- Issue was significant because overseas parties accounted for ~60% of the solar generation pipeline (by GWh/yr of actively pursued projects that could be developed by 2026). These parties also had significant experience, capital and ability to leverage established relationships with suppliers.

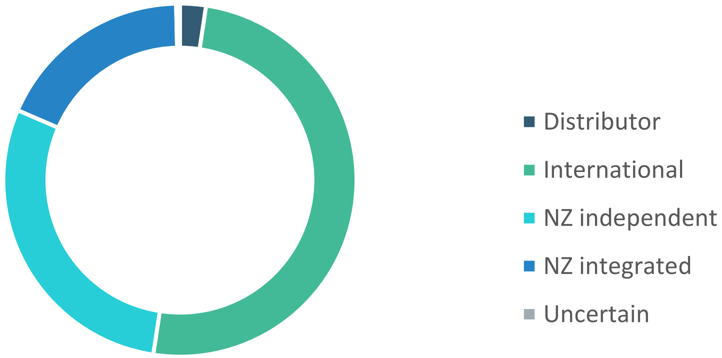
Position in 2023

- The Overseas Investment Office has recently approved a number of solar applications (particularly advertising exemptions) and published its decisions.
- Based on these precedents, overseas solar developers appear much more comfortable about overseas investment approval processes and view them as less of a potential handbrake.
- One developer commented that the regime is now “navigable” and that while it still poses risks these now appear “manageable”.
- Some developers also noted that the costs to obtain consents are significant at $250k-$350k per project and that timeframes can still be long.

Active projects by fuel type



Active solar projects by developer type



Notes

- Based on interviews with developers and other sources.
- Figures based on GWh/yr for actively pursued projects that could be developed by 2027. Assumed capacity factors are biofuel (60%), geothermal (95%), hydro (50%), onshore wind (40%) and solar (20%).
- Some solar generation projects by the four vertically integrated generators are being developed with international partners in a joint venture. These projects are classified as ‘NZ integrated’ rather than ‘International’, but they may require an approval under the Overseas Investment Act.
- “Uncertain” refers to developers whose domicile is unclear (generally because the developer/customer on the Transpower connection application is by a consultancy or distributor on behalf of an unknown developer).

Connecting to the grid seen as most significant barrier, although Transpower's queueing system is an improvement

Previous survey

- Many developers expressed frustration about processes for obtaining connection to the national grid, including:
  - Delays/queues to undertake connection studies
  - Lack of transparency re connection requests, creating potential for wasted effort when developers pursue mutually exclusive projects
  - Uncertainty/delays in getting physical works built once project is committed.

Position in 2023

- While some aspects of the connection process have improved, connection was generally seen as the most significant barrier to generation development (primarily due to the long timeframes to get a connection agreement).

Connection studies

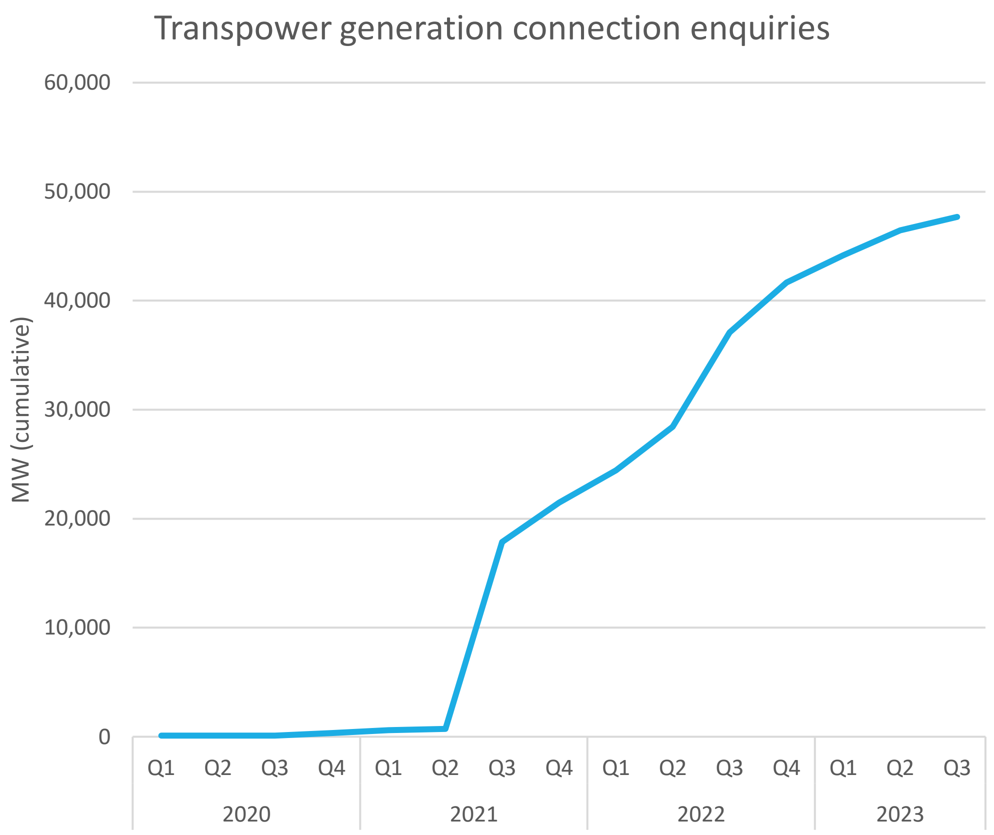
- Developers were generally more positive about recent changes – especially publication of connection study queue and introduction of lodgment fees.
- Developers typically considered changes will:
  - Help to apply resources to projects with higher likelihood of proceeding
  - Reduce likelihood of multiple parties pursuing mutually exclusive projects.
- Some developers suggested fine-tuning will be desirable – e.g. allowing parties to trade queue slots where mutually beneficial.

Physical connection works

- Developers remained wary about timelines for physical work. For this reason, some planned to directly engage construction contractors, rather than have Transpower manage these works on their behalf.

Broader grid capacity

- Turning to the broader grid capacity (as distinct from connection investment), many parties thought bottlenecks would start to emerge because grid investment processes will be unable to match the pace of demand and generation growth.
- Northland region was cited as an example where such pressures are already emerging.



Notes

- Graph based on the capacity (MW) and date of enquiry of projects in Transpower's connection enquiry database as at 1 September 2023.
- Includes data for projects that are speculative or unlikely to proceed unless they have been removed. May also exclude data for enquiries that are no longer proceeding if they have been removed.

Step up in connection interest has stretched distributors

- Engineering more complex than typical distribution connections:
  - most distributors relying on consultants for engineering studies needed to safely integrate large DG onto the network
  - learning process for distributors (and consultancies)
  - generation-specific issues to resolve.

- Managing connection process is resource-intensive:
  - iterative engineering study and design processes for distributor and developer
  - extended commercial negotiation and pricing determination processes
  - equipment procurement and project delivery coordination
  - coordination with Transpower (including as grid owner and system operator, depending on project size).

- Access regime (Part 6) provides a starting point but very common view from both distributors and developers that it needs amending to better suit large DG (e.g. regarding timeframes).

- Some new issues to manage that aren't covered by Part 6, including:
  - queue management
  - congestion management
  - investment coordination
  - vested asset standards, warranties and spares
  - nuances of incremental cost determination.

Several distributors mentioned challenges trying to recruit staff to grow their teams to service increased workloads

Issues relating to reactive power, harmonics, reverse flows at GXPs, interactions between DG, etc.

Grid owner relationship is with the distributor, while system operator relationships has direct relationship with generator (and with distributor).

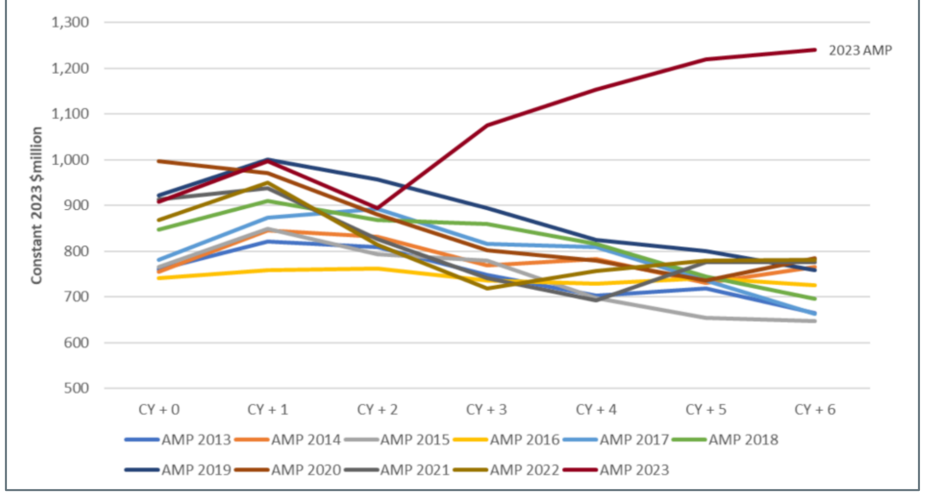
Several distributors have recently developed (or updated) congestion management policies – typically setting out a curtailment hierarchy based on some mix of size, technology and vintage (e.g. last on = first off).

- Burst of DG applications coincides with growing volume of electrification connections – including transport and process heat projects – and general uplift in system growth and renewal planning.

- Complexity, learning, and resourcing issues have contributed to extended application timeframes. Maturation of business processes may lead to improvement in future, though complexity may also grow because easiest projects are developed first.

- Some developers expressed frustration that processes can be very different between EDBs, and that this area would benefit from Authority guidance promoting standardisation.

Figure E2 Comparison of capital expenditure forecasts from EDB AMPs forecasts



Distributor's latest Asset Management Plans (AMPs) collectively forecast much more investment than before. Source: Commerce Commission, p140. [Default-price-quality-paths-for-electricity-distribution-businesses-from-1-April-2025-Issues-paper-2-November-2023.pdf (comcom.govt.nz)].

Network pricing likely to become a barrier once first wave built out

Incremental cost approach not sustainable

- Part 6 requires that DG pays only for incremental costs.
- Typically applied on a per-connection basis, capturing readily identifiable incremental costs only – e.g. new assets, engineering reports. Difficulties with this are:
  - DG does not contribute to shared costs and, as a group, is likely paying less than its full incremental cost. At best, DG is free-riding, which may not be sustainable as DG connections grow
  - a piecemeal approach (incremental funding of incremental capacity) does not support efficient network planning and investment coordination. Taking a more proactive approach creates a first-mover disadvantage problem (i.e. FM must carry cost of anticipatory capacity)
  - pricing differences may distort connection choices (distribution vs. transmission) at the margin. Transmission has more favourable first-mover disadvantage mitigation but allocates generation a larger portion of shared costs.
- In the near term, these dynamics are strongly influencing which DG is built first – i.e. small-scale, shallow (near GXP), or connecting to line with available capacity.
- Network pricing may quickly become a material barrier to investment once first wave of investment has played out and:
  - areas with available capacity for utility-scale projects built out
  - small- and mid-scale projects have absorbed LV network capacity headroom.

"…connection charges in respect of distributed generation must not exceed the incremental costs of providing connection services to the distributed generation"

EIPC Schedule 6.4 clause 2(a)

Some distributors use ongoing injection charges to recover a broader scope of incremental costs – e.g. for additional network operation functions.

Anticipatory capacity can be efficient, but Part 6 loads costs onto the first-mover.

The TPM partially socialises the cost of anticipatory capacity. Otherwise, transmission customers fully fund dedicated connection assets, share the cost of shared connection assets, and pay benefit-based charges that contribute to deeper shared assets.

First wave
Absorbs available capacity, or creates dedicated capacity

Second wave
Pricing reform may enable capacity investment

Third wave
Congestion management to optimise network usage

More balanced pricing arrangements, with DG contributing to shared network costs and with better arrangements for allocating costs of anticipatory capacity, may help ensure DG investment does not stall. Some capacity upgrades may nonetheless still be too large for the early-stage costs to be carried by distributors or their broader customer base.

Common view that changes to the access regime for utility-scale DG are needed

DG network access

- Part 6 provides a distribution network access framework for all distributed generation, covering application process, processing fees, pricing principles, default contract and dispute resolution.
- Fee caps are set for four different size bands, with $5k cap for DG larger than 1 MW. In practice, distributors generally passing on costs of engineering studies and under-recovering internal costs.
- Prescribed process is the same for any DG over 10kW. In practice, engineering and commercial processes for large DG are more iterative than prescribed and timeframes are longer.
- Single default contract available for any size DG. Provides starting point, but in practice both parties typically find they need to negotiate non-regulated contract for large DG. Gaps in default contract include:
  - novation provisions
  - step-in rights for lenders
  - arrangements for pre-purchasing long-lead-time equipment.
- Access regime silent or under-developed on some matters that can be important for large DG:
  - queuing policy for applications (some developers were concerned that processes were uncertain and that EDBs were not strict enough at removing projects from the queue that show minimal progress)
  - congestion management policy, including policy change governance (some developers were concerned that EDBs did not have a congestion management policy in place, or that they were taking a 'proportionate sharing' approach rather than a 'last on = first off' approach)
  - equipment standards and maintenance arrangements
  - staged commitment arrangements
  - engineering design and system study iterations, and coordination with Transpower.

Some aspects of the distribution network access regime differentiate by project size:

	≤10kW	10 to 100 kW	100kW - 1MW	≥1MW	Common themes
Application process Two tiers	○				Process for utility-scale projects is longer and more iterative than contemplated
Fees Four size bands	○	○	○	○	$5k cap for utility scale does not cover costs nor deter speculative applications
Pricing principles One size fits all					Incremental funding does not support efficient network investment and is unlikely to be sustainable long-term
Default contract One size fits all					Default contract provides a starting point only for utility-scale projects.
Dispute resolution One size fits all					n/a

There will always be aspects of utility-scale DG contracts that should be bilaterally negotiated (in a way that small-scale DG developers will not need/want) rather than be set out in default terms. However, there are common features that would be useful additions to the default terms in Part 6.

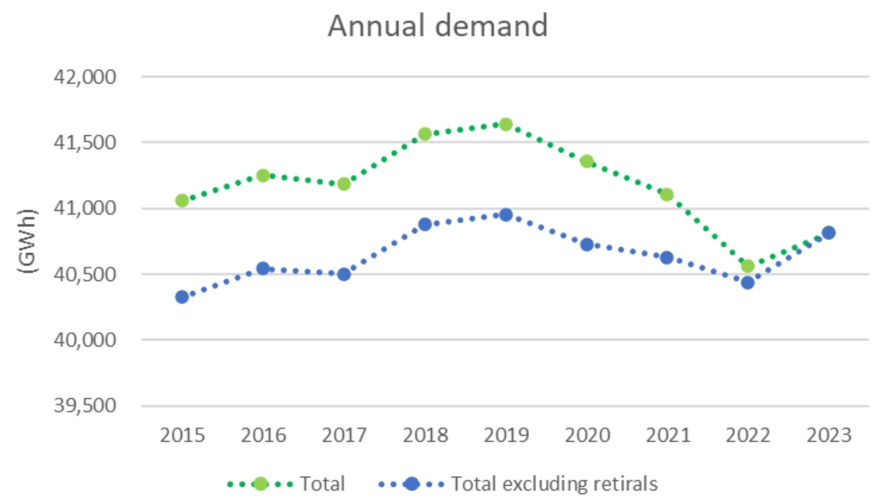
Large-scale DG also presents issues and challenges for the transmission access regime, including in areas such as power factor obligations and harmonics management and regarding tri-partite coordination between Transpower, distributors and DG. Some issues may warrant updates to the regulatory default transmission agreement (including the connection code) while others may be resolved operationally.

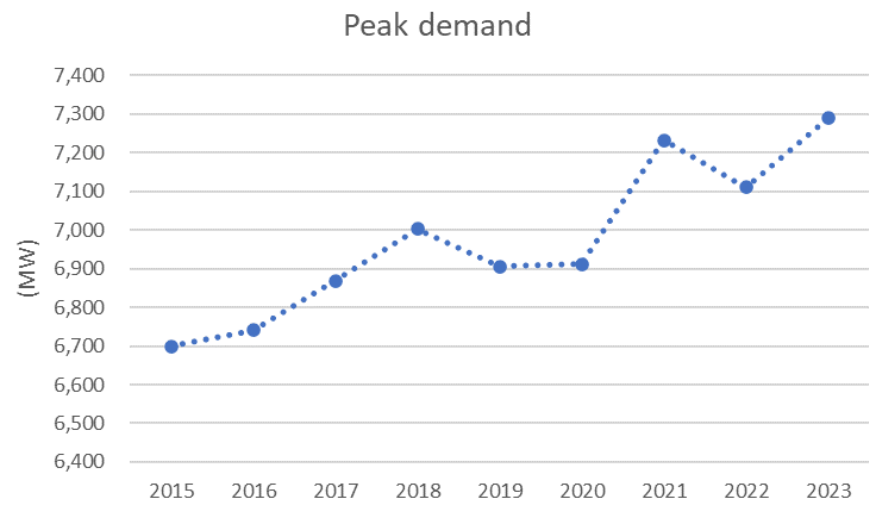
Demand outlook is becoming more of a focus, as the driver of renewable investment shifts from thermal displacement to demand-led

Impetus for renewable build moving from displacement-led to demand-led
- Displacement of fossil-fueled generation has been key driver for renewable investment in recent years – because renewables became cheaper than fossil *baseload* generation.
- However, committed generation by 2025 appears to have met most of this thermal displacement duty.
- Further renewable investment [increasingly] tied on demand growth.

Demand growth expected to take off – but hasn't happened yet
- Developers expect strong demand growth as decarbonisation expands electricity use for heating and transport – e.g. many forecasts predict 50+% by 2050.
- However, there is little sign of growth to date:
  - Annual grid energy demand has been flat or falling since 2015
  - Some of this is due to plant closures in some industries (e.g. pulp & paper, petroleum refining), but even correcting for this, underlying energy demand growth is weak.
  - On the other hand, peak demand has increased significantly.
- Developers generally expect the demand headwinds to wane and tailwinds to build.
- However, uncertainties over timing remain, for example:
  - Rate of industrial heat electrification (large potential but lumpy)
  - Consumer behaviour
  - Policy affecting electricification (e.g. ETS, GIDI, Clean Vehicle Discount Scheme).

Attention starting to focus on shape of demand trajectory
- Developers remain very positive re medium term demand outlook, but there is increasing attention to understand the pace and shape of demand growth.
- Greater awareness that misjudging the demand trajectory could lead to under- or overshooting of new investment.
- One developer observed that "everyone's agreeing that by 2050 [demand] is going to be a lot higher than it is today … the slight elephant in the room is that if you look at what demand growth is doing, if you put it on a chart and draw a trendline, you can convince yourself it is going up, but only just".





Notes
- "Demand" is demand for generation, as measured by generation data published on EMI.
- Years are YE September.
- Total excluding retirals removes Kawerau mill and Marsden Refinery demand from total
- Total demand shown for peak chart. Industrial demand often contributes little to system peak because it is responsive to price.

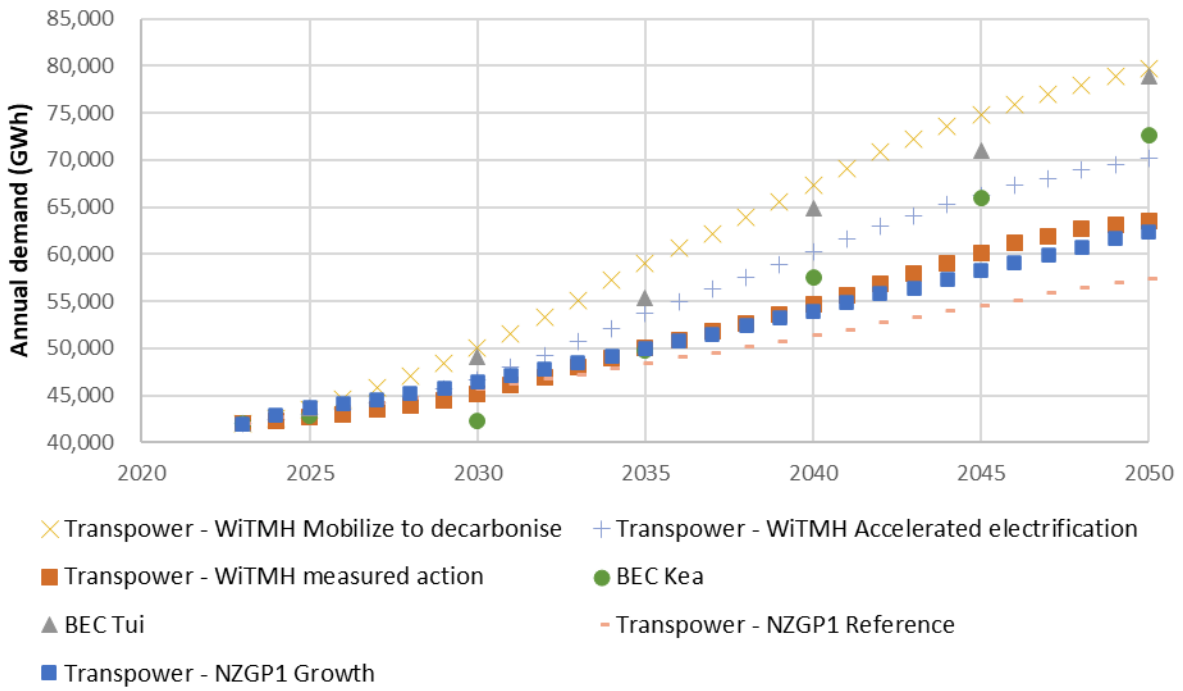
Shift to demand-led development will pose some new challenges

Better understanding the demand outlook

- Chart shows projected demand based on five different forecasts from Transpower, as well as two from BusinessNZ Energy Council's modelling.
- The forecasts for 2030 range from 42.3 TWh to 50.0 TWh.
- This corresponds to virtually no growth in the lower case, to more than 20% compared to 2023.
- Understanding which demand trajectory NZ is on has big implications for the development eco-system.
- This raises a question about what could be done to narrow the range of uncertainty around demand forecasts – and quickly identify and share any emerging trends.

Increasing flexibility of the development pipeline

- It is one thing to better understand the demand outlook – it is also important for development pace to be able to flex to match demand trends.
- While the number of projects being actively considered has definitely stepped up in recent years, it remains to be seen whether the development 'system ' has sufficient flexibility to respond smoothly to changes in the demand outlook.
- Potential areas of particular challenge (see relevant sections) include:
  - Consenting processes (especially for wind and network investments)
  - Connection processes.



Notes

- Transpower demand forecasts have been scaled up to account for grid losses
- Demand forecasts normalized to a consistent starting point of 42,000 GWh in 2023.
- Tiwai has been added back in to NZGP1 forecasts

Uncertainty about Tiwai smelter affects development timing for some projects, but is seen as a temporary factor

Future Tiwai smelter operation remains uncertain

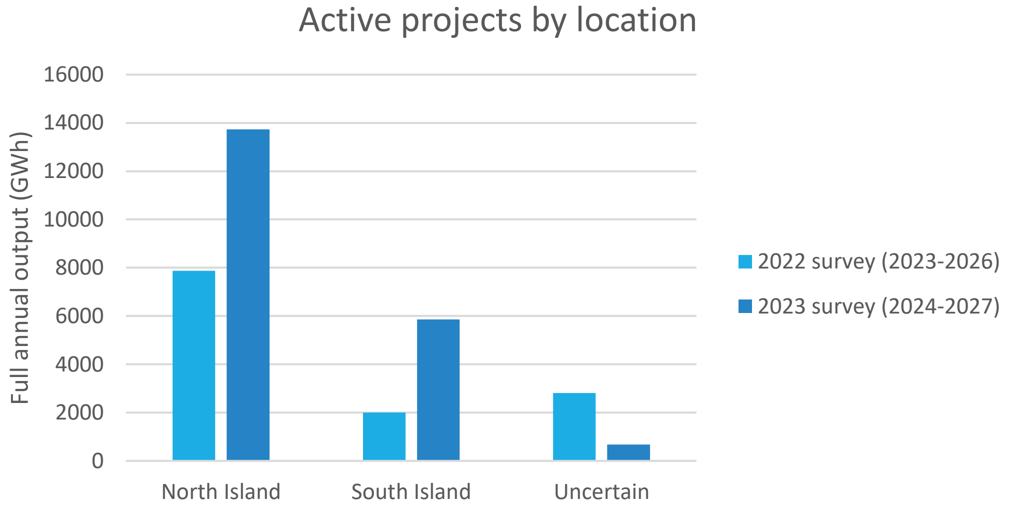
- Tiwai aluminium smelter accounts for ~12% of national demand and its current supply arrangements expire after December 2024.
- Future operation of smelter (volume, duration, flexibility) are linked to negotiations for new supply arrangements.

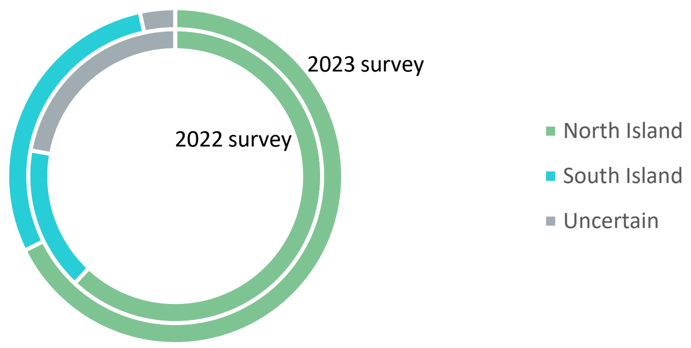
Smelter closure would push back FID dates for some projects

- A slate of projects that could come on stream in 2025/26 (i.e. to broadly match ongoing smelter demand) appear ready or close to final investment decisions (FID).
- If the smelter ceases/reduces operation post 2025, FID for these projects is likely to be delayed.
- Conversely, if the smelter announces continued operation, FID for these projects would likely occur very quickly. Having said that, it would take 1-2 years to build these projects, so it is now impossible to seamlessly ramp up new supply to match any ongoing smelter demand.

Broader sentiment remains positive despite smelter uncertainty

- While interviewees acknowledged smelter uncertainty, they typically did not see uncertainty as a major handbrake.
- Rather they tended to look through that uncertainty and focus on the broader demand outlook.
- On that front, developer interest in the South Island had increased relative to the last survey – despite the lack of resolution to Tiwai smelter uncertainty (although most projects by GWh/yr are still located in the North Island).
- This was reflected in survey responses (where project locations were known) and feedback from network operators.





Notes

- Figures based on GWh/yr for actively pursued projects that could be developed by 2027. Assumed capacity factors are biofuel (60%), geothermal (95%), hydro (50%), onshore wind (40%) and solar (20%).
- "Uncertain" projects are those where developers did not provide sufficient project details to identify where the project is located.

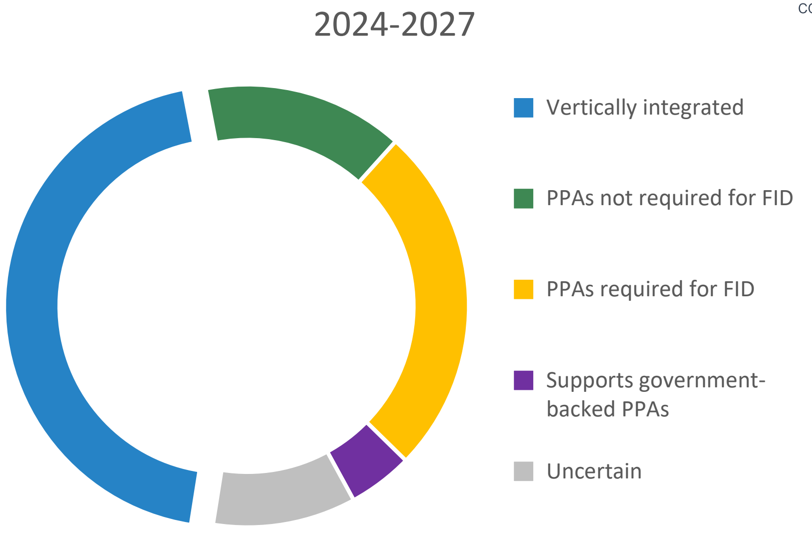
Developers expressed a variety of views regarding the necessity of securing power purchase agreements pre-FID

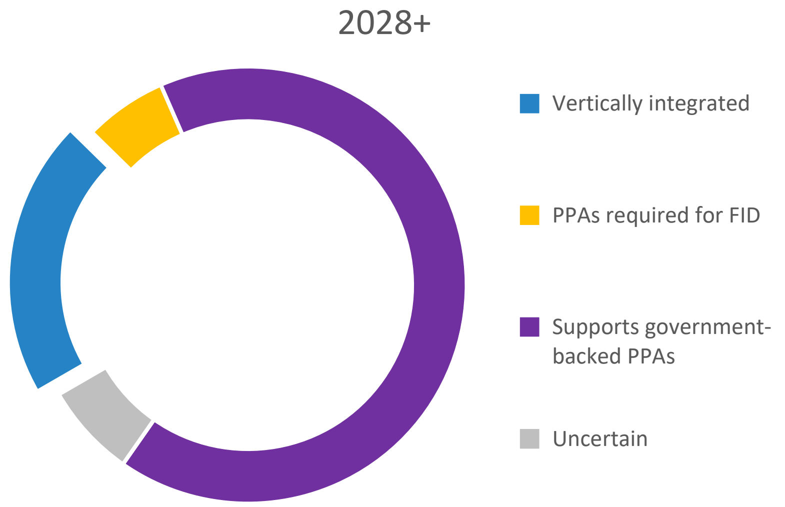
Generator-retailers are least reliant on securing PPA pre-FID
- Vertically integrated developers typically expressed willingness to make build decisions without needing PPA contracts for projects – relying instead on growing existing sales channels to sell project output.

Most independents see PPAs as pre-requisite for FID
- Around 55% of independent developers we interviewed (by output, for actively pursued projects that could be operating by 2027) indicated that securing longer-term PPAs would be necessary prior to FID.
- In particular, they said such arrangements were necessary to obtain acceptable debt finance arrangements.
- Having said that, most of these parties were cautiously optimistic about securing PPAs (see next slide).

Some independents willing to commit to FID without a PPA
- About 26% of independent developers indicated willingness to build without a PPA in place – this stance appeared to reflect the:
  - view by some parties that selling output/renewable certificates from an operational project is easier than selling 'off the plans'
  - ability of some independents to treat NZ projects as part of wider international portfolio, rather than relying on project finance
  - willingness of some parties to sell offtake via shorter term (<5 years) deals, such as bilateral contracts or ASX futures.

Some independents want government-backed PPAs
- Some developers were skeptical about the rate of PPA market development saying vertically integrated players would not support it.
- They preferred government support for offtake deals – ranging from government use of PPAs for its own power needs through to large scale procurement schemes as per United Kingdom and New South Wales.
- Only one developer of projects that could be completed in the next four years expressed this view, noting this may reflect a selection bias (i.e. developers favoring government-backed PPAs may prefer jurisdictions where it already exists).
- Most actively pursued projects (by GWh) that are expected in 2028 and beyond are offshore wind, with these developers tending to support government-backed PPAs. Other generation technologies have shorter lead times, so actively pursued projects will generally be completed sooner than 2028. However, as we get closer to 2028, it is possible that additional onshore projects of various types will become actively pursued for development post-2028. If that occurs, it is unclear whether the associated change in project mix would affect the reported share of preferences among developers regarding PPAs.





Notes
- Based on projects being developed by interviewed parties only.
- Figures based on GWh/yr for actively pursued projects. Assumed capacity factors are biofuel (60%), geothermal (95%), hydro (50%), onshore wind (40%) and solar (20%).
- Percentages in the text box exclude vertically integrated developers' projects (i.e. independent developers only), but all actively pursued projects are included in the charts above).
- "Uncertain" projects are those being developed by parties that did not disclose in interviews the extent to which they would require PPAs to reach final investment decision.

While the PPA market is not deep, there are signs it has developed in the last 12-18 months

concept consulting

Interview comments on PPA terms and structures

- Developers with mature (or near mature) projects generally reported that arranging a PPA was feasible with reasonable buyer interest.
- Contract durations reportedly ranged from a few years out to 20+ years.
- Longer term deals were said to be more cost-based (i.e. lower prices) compared to shorter deals.
- Price adjustment mechanisms (resets/indexing) were typically present for longer duration contracts.
- Some customers appeared willing to pay a 'green premium' where a deal could be directly linked to a new renewable project.
- For longer deals, seller attention focused mainly on industrial and commercial customers due to their perceived higher credit quality.
- Structures for managing volume/shape risk varied considerably – ranging from pay-as-produced[1] contracts (where a buyer assumes volume and shape risk) through to sleeved arrangements[2] (where a sleeve provider covers mismatches between project output and buyer requirements).
- Customers seeking sleeves may find them easier to arrange through their existing supplier (i.e. a vertically integrated portfolio generator), than relying on an independent developer to find a sleeving partner.
- The availability of flexibility products was expected to be a key issue for the sector.
- Customers with some flexibility over their usage profile can be especially attractive and can use flexibility that to obtain pricing benefits.

Recent announced corporate PPAs signed in New Zealand

Date	Buyer	Seller	Technology	Term	Volume (approx.)
Sep-2023	Warehouse Group	Lodestone Energy	Solar	Undisclosed	Undisclosed
May-2023	Microsoft	Contact Energy	Geothermal	10 years	51.4 MW
May-2023	NZ Steel	Contact Energy	Undisclosed	10 years	30 MW
April-2023	Amazon	Mercury Energy	Wind	15 years	51.5 MW
Mar-2023	Ryman Healthcare	Mercury Energy	Solar	10 years	20 MW

2023 Survey

One service provider commented that few weeks pass without a new PPA RFP being issued and that "attractive projects do attract competitive interest"

"This time last year we would have already seen an uptick in the number of PPA discussions, but it has certainly then increased, probably double-fold, again in the last year" – service provider

"It's been a good three years where there has been consistent corporate and gentailer interest … My biggest fear is that you end up with the offtake market being tailored to what suits the book of the big five, rather than something that encourages new demand or accelerates decarbonization, but I'm not sure if there is anything massive that needs to be done" – independent developer

"PPA market seems to be growing, there are more platforms that are appearing now" – independent developer

Interview comments from different parties

Notes

1. Under pay-as-produced arrangements, the buyer purchases the (varying) volume produced each half hour from a defined generator – these deals are also called 'generation-following' contracts.
2. Under sleeved arrangements, the varying half-hourly production from a renewable project is passed through a 'sleeve' to the buyer, so the resulting offtake profile exactly matches the buyer's half-hourly needs. The sleeve is provided by another party, such as a portfolio generator with flexible generation.

Notes

- Table sourced from Transpower's insight paper, "Corporate Power Purchase Agreements", published in October 2023. See https://static.transpower.co.nz/public/uncontrolled_docs/Corporate%20PPA%20Final%20%28publish%29.pdf?VersionId=zsFR4e7sdn73V36LkRZrL2ztLJjnJkbf

Tight markets for equipment and labour remain key challenges for developers, putting upward pressure on build costs – especially for wind projects

Overview
- Developers say global supply of equipment (generation, switchgear, transformers, cables) remains tight – creating timetable risks and cost pressures.
- However, differences are starting to emerge among various technologies.

Wind
- Wind developers say they are facing a big step up in project costs (see later slides).
- Non-price terms have also deteriorated with turbine suppliers no longer willing to offer fully wrapped EPC contracts (i.e. turn-key deals).

Solar
- Solar developers report that the cost of panels has returned to below pre-Covid levels. However, total installation costs remain relatively high due to the cost of racks, switchgear, transformers, labour, etc.
- Developers say that installing solar equipment remains hard due to limited experience of NZ contractors and workforce recruitment challenges in rural areas.
- However, there are signs a pool of EPC contractors may be developing - as local parties accumulate experience and/or overseas parties enter the market.

Battery energy storage
- Developers said record high lithium costs (a major battery component) in 2022 led some projects to be delayed or shelved.
- However, falling lithium costs (down ~60% since 2022) may rekindle interest.

2023 Survey

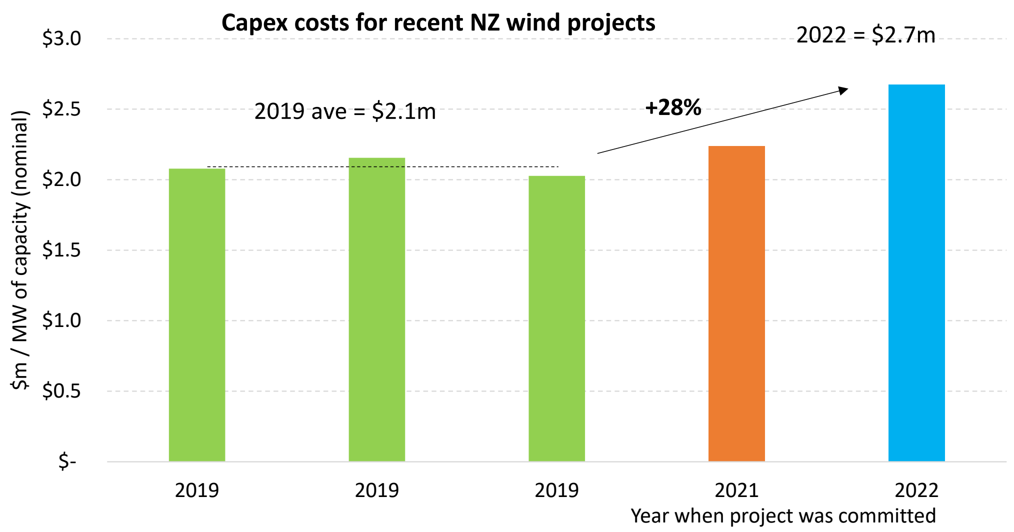
Developers and advisers expressed comments like:

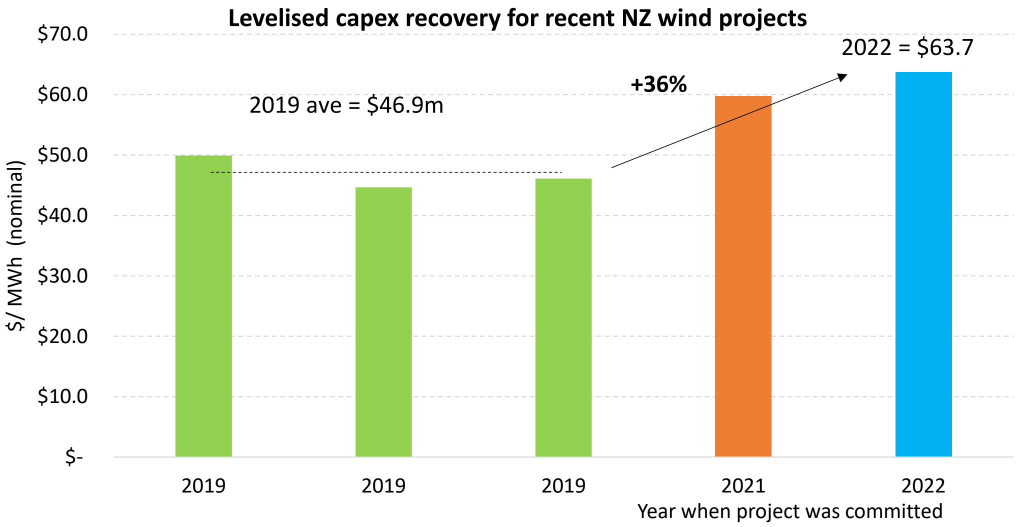
- *"Wind project costs have gone ballistic"*
- *"Wind costs are at all time high"*
- *"Wind costs have blown out"*

Interview comments from different parties

Higher cost for wind projects is pushing up cost of new supply, with broader implications for the system

- Developers (both independent and incumbent) consistently referenced a sizeable step up in wind project costs.
- Analysis of published data corroborates this feedback.
- As shown in charts, capital costs for NZ wind generation projects have risen markedly since 2019.
- In $/MW terms, cost for most recent project was up 28% compared to average project costs pre-Covid.
- In $/MWh terms, cost for most recent project was up 36%.
- The increase is meaningful because capital costs typically account for 80%+ of the total levelised cost of energy (LCOE) for wind generation.
- Furthermore, the 'cost-point' for wind generation is important for the overall NZ electricity system, because this generation source is expected to form the backbone of new supply as:
  - NZ wind resource is world class, and its production profile aligns fairly well with NZ's seasonal demand profile
  - geothermal is attractive because it is not intermittent and has competitive costs, but its growth constrained by resource availability
  - solar is growing as it becomes more competitive, but its seasonal production profile aligns less well than wind with NZ's demand profile.

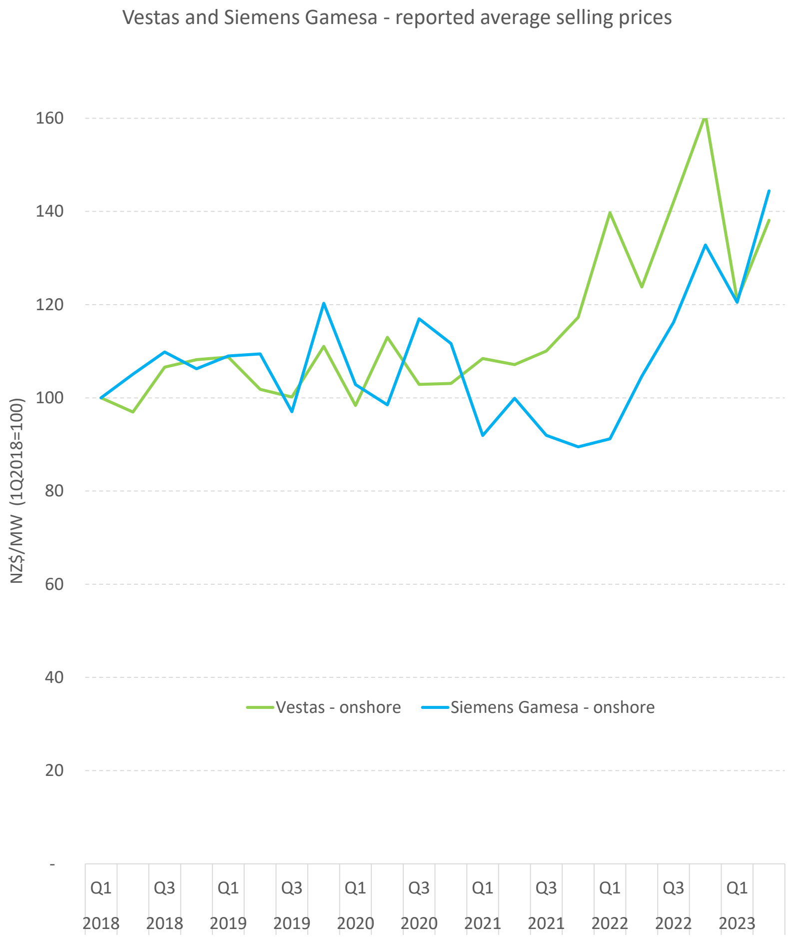




Notes
- Based on company disclosures. Reflects cost estimates at date of project commitment (i.e. excludes any subsequent announced cost increases).

Change in pricing approach by major turbine suppliers has been key driver of higher costs for developers …

- Vestas, Siemens Gamesa, and GE are major suppliers of wind turbine generators (WTGs) at global level.
- Only Vestas and Siemens Gamesa are currently active in NZ.
- These major WTG suppliers have incurred large losses in recent years (EUR -4.5 bn in FY2022) – a key factor they cite has been unsustainable pricing for WTGs.
- These companies have been extremely vocal about changes in their pricing strategies designed to lift WTG sale prices to levels they consider sustainable.
- Analysis of Vestas and Siemens Gamesa sales data indicates that they have put their stated new strategies into practice.
- As shown in chart, in 2023 WTG average selling prices for Vestas and Siemens Gamesa were around 30-40% higher than levels pre-Covid.
- While the figures reflect global averages, there is no reason to expect NZ WTG buyers to receive preferential treatment.



WTG average selling prices.xlsx

Notes
- Based on company disclosures of average selling prices for onshore turbines in Euros/MW. Data converted to NZ$ based on prevailing exchange rates.

Higher wind turbine prices likely to persist for some time

Current WTG suppliers

- Vestas and Siemens Gamesa will presumably seek to maintain their revised pricing approaches as long as possible:
  - Both companies recorded losses in 2022/23
  - While some WTG input costs (e.g. steel) are falling, suppliers are unlikely to pass benefits through to customers given negative manufacturer margins
  - Buyers' negotiating power in NZ is constrained – as one interviewee commented, WTG supply in NZ is a "two-horse race".

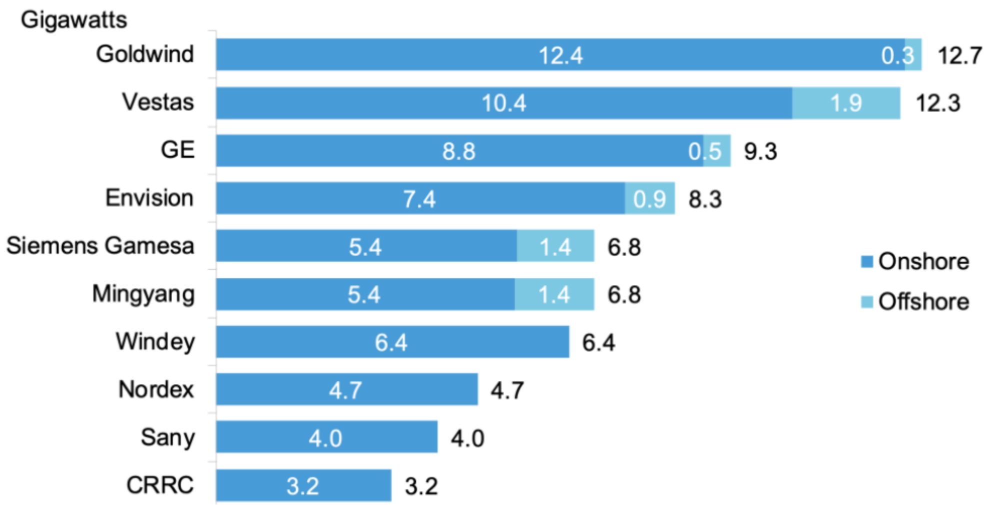
Potential for new WTG player(s)

- Actual or threatened entry by new player(s) could alter market dynamics and put downward pressure on WTG prices for NZ projects.
- Possible new players include Goldwind or Envision – both of which are large, established suppliers based in Asia.
- Asian suppliers are especially relevant because they are widely thought to enjoy manufacturing cost advantages relative to western competitors.
- As far as we are aware, there are no technical factors constraining use of Asian WTGs in NZ for class II sites and above.
- Indeed, we understand some developers have held discussions with potential new suppliers.
- However, it does not appear that there has been much interest from Asian suppliers to enter the NZ market to date. Some developers also indicated a preference for suppliers with established teams and relationships in NZ.

Outlook

- These factors suggest NZ wind projects are likely to face elevated costs for some time – unless a new entrant emerges, or some other external shock resets pricing dynamics.

Top 10 global wind turbine suppliers in 2022



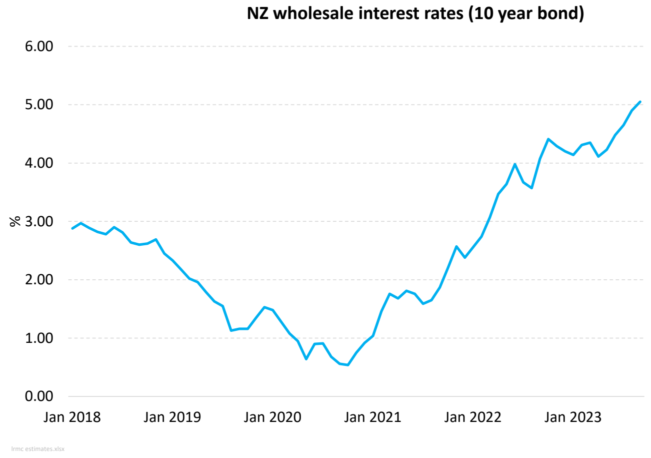
Source: BloombergNEF

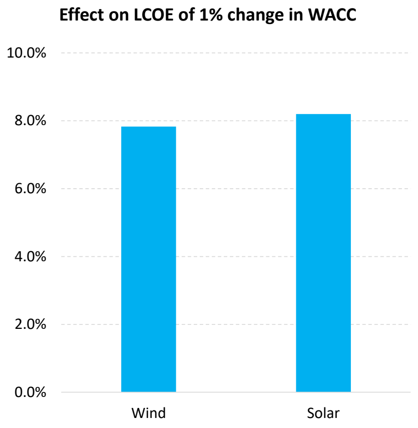
Capital remains available for projects but at a significantly higher cost – the softer NZD is also putting upward pressure on costs

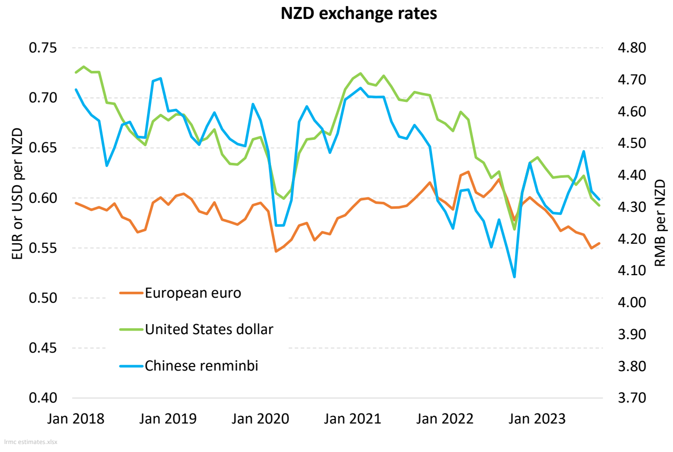
Capital availability
- Developers were positive about the *availability* of capital for renewable projects – with most ranking this as a low source of concern.
- To the extent any negatives were expressed, these related to:
  - An increase in the cost of capital (see below)
  - Possibility that Australian banks may misapply lessons from their home market to NZ lending – e.g. overestimate likelihood of excess solar supply (noting rooftop solar is not subsidised in NZ)
  - Concern that non-renewable projects may face undue hurdles to obtain funding.

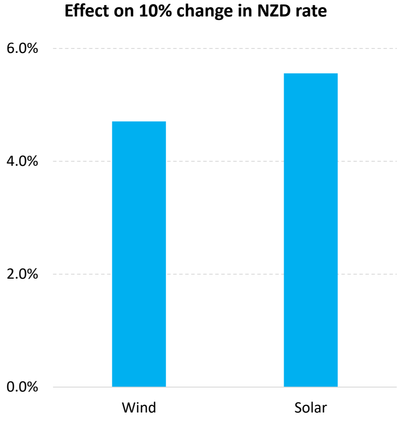
Interest rates
- Renewable projects are sensitive to changes in cost of capital because most expenditure is incurred upfront.
- Bond rates have increased by 4%+ since record lows of 2020 – and are ~2% higher than levels pre-Covid.
- Higher bond rates have raised cost of capital for new projects – noting each 1% increase in WACC raises solar and wind LCOE by ~8%.

Exchange rate
- Imported components account for roughly 50-70% of renewable costs depending specific projects.
- Compared to 5-year averages, NZD is currently low against key currencies in which generation components are priced.
- Forward market data suggests NZD unlikely to strengthen to former levels in foreseeable future.
- A 10% fall in NZD rates adds around 5% to LCOE for solar and wind costs.









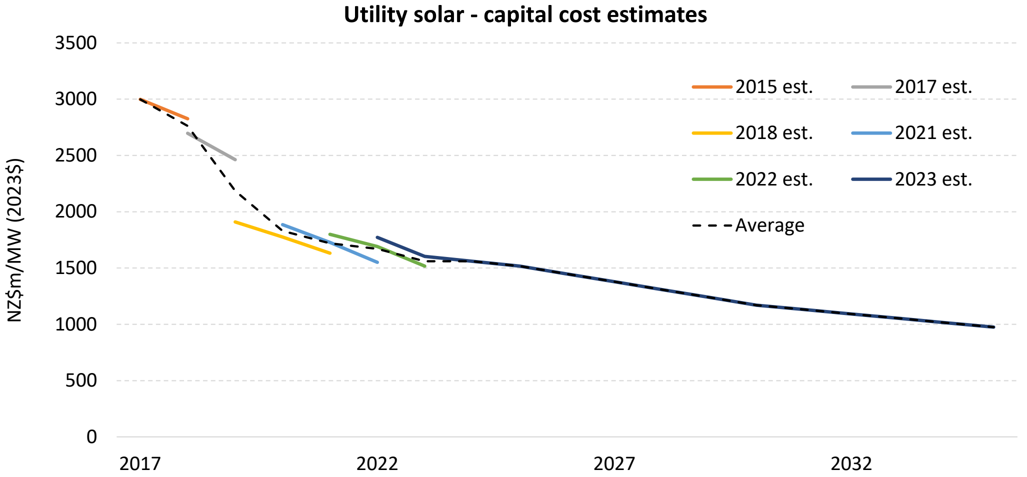
Notes
- Changes in LCOE are calculated based on estimated costs for illustrative 'reference' projects using 2022 data as starting point. Figures should be treated as indicative.

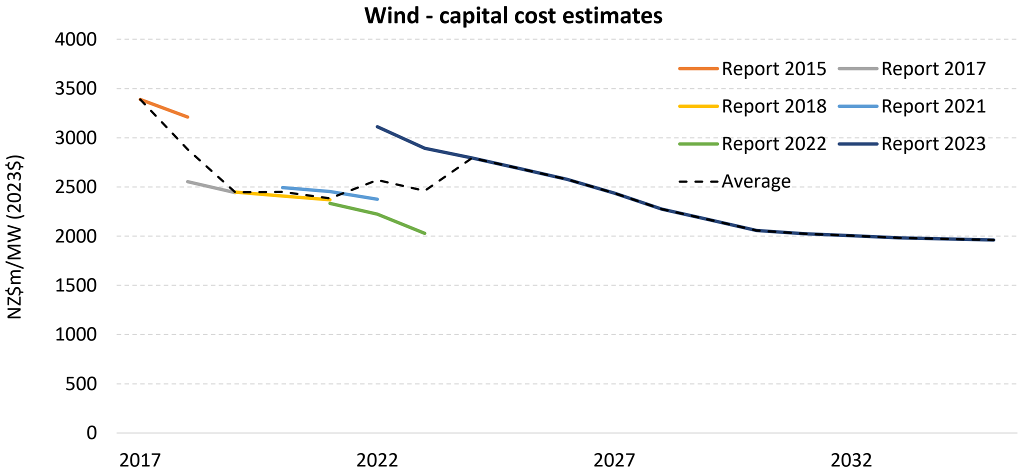
Changes to equipment & construction costs, interest rates and exchange rates create a complex mix of forces …

Relative shift in cost of solar & wind
- Wind project costs have risen sharply and appear unlikely to fall soon - conversely solar costs are easing and may fall further.
- If this *relative* cost shift persists, it should tilt development more towards solar (noting a mix will apply - also including geothermal & other technologies).

Weak but volatile NZD
- NZD has been relatively soft but also quite volatile – especially against the USD and RMB.
- Weak NZD hurts all projects (though differentially depending on currency in which components are priced).
- However, volatility may favour projects with flexibility to execute quickly during windows when NZD favourable.
- We are not aware of many wind projects that could execute quickly but some solar projects could potentially move swiftly.

Longer term outlook
- Most forecasts predict longer term downward trend in costs for wind, solar and battery storage due learning curve improvements – especially for solar and batteries.
- For example, Australia’s CSIRO regularly publishes capex estimates for Australian projects.
- An analysis of these reports shows a consistent expectation of falling costs as technology improves, but with occasional resetting of the ‘starting point’ due to external market factors.
- Turning to the future, we share the view that capital costs are likely to trend downward in real terms due to technology gains – and think the key uncertainty in the next few years is whether wind turbine pricing dynamics will reset.



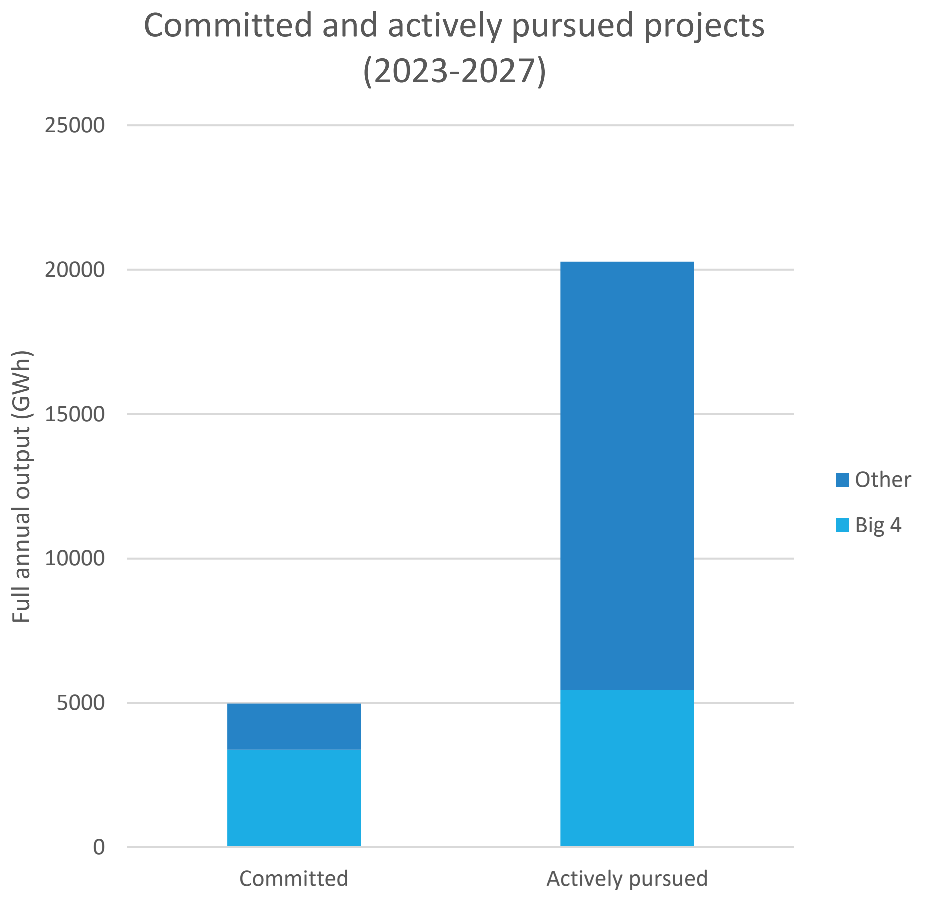


Notes
- Concept analysis of CSIRO reports. Estimates converted into NZD $2023 at prevailing exchange rate and CPI deflator. Basis for estimates may not be entirely consistent over time because CSIRO scenarios sometimes alter between reports. Nonetheless, we believe the analysis provides a reasonable guide to how estimated capital cost trajectories have altered through time.

Competition appears to be strong enough that large incumbent developers are not deferring projects to keep wholesale prices elevated

Previous survey
- Our previous survey found that it was unclear whether large incumbent suppliers are seeking to prolong the period of elevated wholesale prices (i.e. by tempering the pace of their investment to avoid depressing the price and therefore the revenue they receive from their existing generation).
- While the four largest generators have significantly lifted their development efforts in recent years – with major committed projects underway and more potential developments under consideration, some independents suggested that it was hard to attract interest from major generators, even with apparently attractive projects/power purchase offers – possibly due to cannibalization concerns.

Position in 2023
- As with last year, some independents questioned whether some of the large gentailers were difficult to engage with because they didn't want to support competitors. However, the weight of opinion among independent developers suggests they are less concerned about this issue in this year's survey than they were a year ago. There have also been several examples of joint ventures, project acquisitions, and firming arrangements between independents and incumbents over the last year.
- However, there are conflicting views and commercial sensitivity means that it is difficult to get a clear answer as to the extent of any issues.
- Some incumbent generators noted a general preference to take a "cradle-to-grave" approach to development, i.e. to build, own and operate an asset themselves, rather than to enter into a JV or as a purchaser under an offtake agreement. However, comments and activity from some incumbents has shown that they are still willing to enter JVs (if the counterparty brings something more to the project than just an idea, such as relevant skills and relationships) or to purchase offtake (if the price is attractive and realistic and the counterparty is reliable).



Notes
- Figures based on GWh/yr. Assumed capacity factors are biofuel (60%), geothermal (95%), hydro (50%), onshore wind (40%) and solar (20%).

Policy and regulatory uncertainties were raised by developers as a concern but were not front of mind for most parties

- Developers rated NZ as being attractive relative to many other jurisdictions – citing broad support for climate action, established electricity market frameworks and low corruption.
- However, many parties noted existing regulatory arrangements are not well suited to developing renewable generation 'at pace' – especially environmental consenting arrangements.
- Many interviewees noted the increased uncertainty in election years – but emphasised a need to take a longer view when making their investment decisions.
- Most renewable developers broadly supported current electricity market arrangements and preferred to evolve rather than replace them. However, some renewable developers supported introduction of government–backed PPAs (see earlier).
- Some interviewees commented that policies relating to thermal generation are a key area of uncertainty – due to conflicting signals between ETS settings, renewable targets, biofuels, hydrogen, gas and coal policies.
- Parties said it was important to clarify policy uncertainties to enable orderly decisions about thermal generation retention/retirement, fuel markets, batteries and other flexibility investments.

2023 Survey

"We are in a footrace with other markets to attract capital, talent, technology … the more we can take away those pain points for investors, the more attractive the environment could be" – independent developer

"Regulatory stability is hugely important to the pace of decarbonization – small, incremental optimisations are fine, kneejerk reactions to problems that will probably be solved by investor confidence and smart people applying their minds to it, just stand back and let that happen" – independent developer

The "whippiness of ETS settings doesn't help" and the "RMA is a nightmare" – adviser

"If you did a survey of the world, you'd find New Zealand was one of the hardest countries in the world to get consent for a power plant of any kind" – international developer

Interview comments from different parties

Areas for potential consideration

While policy recommendations are outside the scope of our report, these issues have been identified for potential consideration by the Authority

Reduce pipeline friction

- Existing arrangements are not well suited to achieving generation development at pace. Furthermore, friction is likely to increase in some areas as pre-existing system headroom is used up. The Authority should consider options to address friction in connection and network expansion processes. It should also support other agencies to further streamline environmental and overseas investment consenting processes.

Improve pipeline information

- Public information about the pipeline has improved but remains fuzzy in key areas. For example, it appears around 1,400 GWh of new projects are in construction or committed for development, but this status is not necessarily clear in public sources. This difference is material and equates to more than one year of national demand growth. Developers, customers and other stakeholders need clearer, and more timely information on project status to reduce the likelihood of surprises, which could disrupt investment confidence.

Active monitoring

- Forward prices have a declining profile over time but remain above the estimated cost of new supply. There is no evidence from this survey that major participants are impeding the pace of new supply expansion. Indeed, they are all actively pursuing their own projects, and there are also examples where some have supported independent competitor projects, via offtake agreements, firming contracts or joint ventures etc. Nonetheless, it remains critical for the Authority to continue its active monitoring of competition in new investment and offtake agreement areas, since timely new investment is the best solution to address current tight supply conditions. A particular issue the Authority could consider in this context is the cause of the rising premium in forward prices at Otahuhu relative to Benmore.

Appendix – data fields and assumptions

Data tables legend

Type of developer	Big four?	Development location	Connection level	Project confidentiality	PPA requirements
NZ integrated (developer is domestic generator retailer with significant retail portfolio)	Big four (developer is one of the largest four generator-retailers)	North Island	Grid (project will connect directly to a grid injection point)	Public (project was discoverable in the public domain)	PPAs not required (project could reach final investment decision without a PPA in place – i.e. developer willing to take merchant risk – noting that this does not necessarily mean that there will not be a PPA for the project)
NZ independent (developer is a smaller domestic developer with no/small retail portfolio)	Other (other developers, including independents, smaller generator-retailers and international developers)	South Island	EDB (project will be distributed generation connecting to an electricity distribution network)	Non-public (project could not be found in the public domain)	PPAs required (project will require a PPA to reach final investment decision)
International (developer has over 25% overseas ownership)		Uncertain (unclear where project will be located)	Uncertain (unclear what level project will connect)	Public portfolio only (project could not be found in the public domain, but developer has publicly announced pipeline of projects)	PPAs required (supports government-backed PPAs) (as above, but developer also expressed a preference that the government offer PPAs to encourage renewable development)
				Uncertain (insufficient details about project to determine whether it has been announced publicly)	Vertically integrated (developer has a retail portfolio – noting that this does not necessarily mean that there will not be a PPA for the project)
					Uncertain (developer did not express an opinion in interview regarding the need for PPA)

Capacity factor assumptions

Biofuel	60%
Gas	15%
Geo	95%
Hydro	50%
Offshore wind	55%
Onshore wind	40%
Solar (utility scale)	20%
Solar (mid-scale)	15%
Solar (small-scale)	14%

Notes

- Where developers provided a yearly generation output figure (in GWh/yr), we have used this figure. In other cases we have calculated generation output based on the capacity of the plant (in MW) using the assumed capacity factors on this slide.

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