Contact Energy Submission

Consultation on Advancing New Zealand's Energy Transition

2 November 2023

Introduction

1. Thank you for the opportunity to provide our views on the Consultation papers on advancing New Zealand's energy transition.
2. We begin this submission by discussing our role through the transition, and some of the key actions we already have underway.
3. We then move on to discuss ways that government can best support the transition, by ensuring that regulatory settings are working as intended, and there are no barriers to particular technology options, or distortions that favour one technology over another.
4. We recommend that government focus on four key areas:
    a. Support the robust pipeline of intermittent and baseload renewable energy by streamlining the consenting regime and maintaining stability in the wholesale market;
    b. Improve the regulatory settings for flexibility, including thermal, hydro, lithium-ion batteries, and demand response, so that the market has a full range of options to choose from;
    c. Ensure there are no barriers to electrification projects so that demand growth can keep up with expectations; and
    d. Support consumers through the transition.

5. We have also included two attachments to our submission. The first summarises all the recommendations made in this paper. The second provides responses to specific consultation questions.

Contact Energy's role in the Transition

6. The energy sector is going through an exciting transition as we respond to the challenge of decarbonisation. Electricity is the key to decarbonising significant parts of the New Zealand economy, including transportation, space heating, and process heat.
7. Contact Energy is leaning in on this opportunity. Our strategy is focussed on leading New Zealand's decarbonisation, based on four key strategic pillars:
    a. growing demand for renewable electricity;
    b. growing renewable electricity capacity;
    c. decarbonising our portfolio, and
    d. creating outstanding customer experiences.

Growing demand

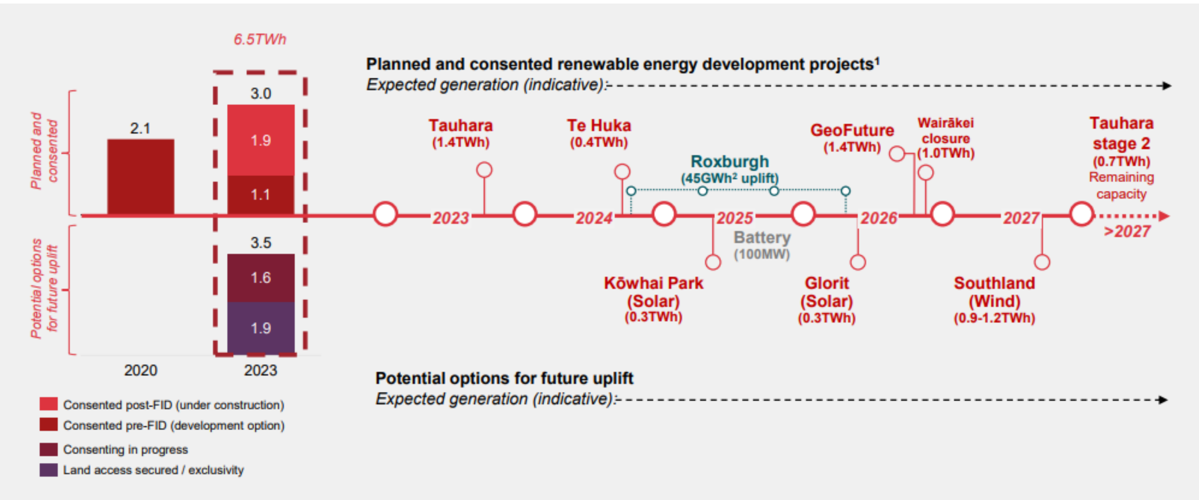
8. A key part of our strategy is to work with our customers to find the best opportunities for electrification and to design innovative electricity supply agreements to get them across the line.

9. Simply Energy is a subsidiary of Contact that focusses on growing demand, particularly process heat conversions. They have supported a number of decarbonisation projects, including the innovative electricity agreement with New Zealand Steel. Under this agreement the electric arc furnace will not operate during the morning and evening peaks during winter months. This drastically reduces the energy costs for NZ Steel, making the conversion possible. It also reduces the stress on the electricity system during the highest peaks, reducing the need for high emitting thermal stations to run.

Growing renewable electricity

10. Along with the rest of the market we are putting billions of dollars of investment to grow renewable energy capacity in New Zealand. We have an ambitious plan to add up to 6.5TWh of new capacity this decade, which will add 15% more output to the New Zealand market – all privately funded. This includes the commissioning of the 174MW Tauhara geothermal power station in the coming months. But as shown in figure 1 below our plans include more geothermal, batteries, solar, and wind. This is critical to provide confidence that there will be enough capacity to support decarbonisation projects.

Figure 1: Contact Energy Renewable Development Pipeline

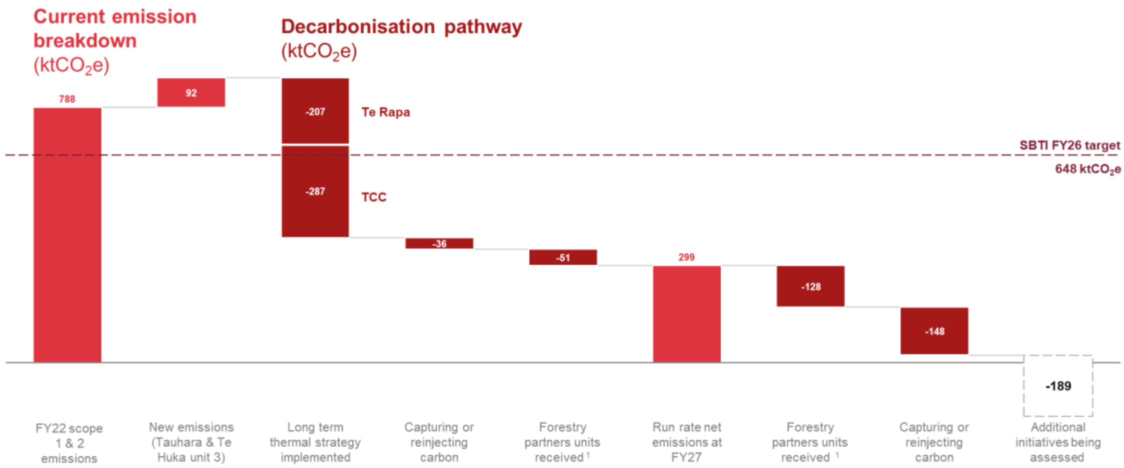


Decarbonising our portfolio

11. Contact's generation portfolio consists of renewable hydro and geothermal, complemented by a number of flexible thermal assets. Together, these assets produced 527ktCO2e in 2022/23, which is about 0.7% of New Zealand's total emissions.

12. We have robust plans to shift to net zero emissions from generation by 2035 (figure 2), while retaining system security and stability. This consists of:
    a. Decommissioning baseload thermal assets. Since 2008 we have decommissioned more than 1,000MW of baseload thermal, and replaced this with renewable geothermal assets. Our next step in this journey will be the retirement of the 377MW Taranaki Combined Cycle plant by the end of 2024, which together with the recent closure of Te Rapa will reduce scope 1 emissions from generation by half.
    b. Capturing geothermal emissions. We have undertaken a successful trial of capture and reinjection of geothermal emissions at our Te Huka plant. We are in the process of rolling carbon capture technology out across our geothermal portfolio.
    c. Sustainable forestry investments to offset the hardest to abate emissions. Our highly flexible thermal 'peaking' plants at Taranaki and Whirinaki are critical for keeping the lights on when demand is highest. We offset these emissions with responsible forestry.

Figure 2: Contact Energy pathway to Net Zero Scope 1 and 2 emissions by 2035



Note: Analysis is based on FY22 actual scope 1 and 2 emissions (indicative of mean year generation). Utilisation of the Peakers will vary over future years depending on hydro sequences and new technologies. Expected net impact of the Wairakei replacement, involving plans for carbon capture, is included in the second tranche of "capturing or reinjecting carbon".
[1] Includes expected units from Drylandcarbon One Limited Partnership and Forest Partners Limited Partnership. Units are shown per annum and are based on current information and may fluctuate based on climate conditions and/or regulatory updates.

Outstanding Customer Experiences

13. We pride ourselves on delivering a top-class experience to our customers. This was recognised in 2022 when we won the coveted 'Retailer of the Year' award.

14. One way we deliver for customers is by providing innovative plans that help consumers shift their load out of the highest cost periods. This reduces costs for us, the benefit of which we can pass on to consumers, keeping electricity prices low through the transition. Our most popular ‘time of use’ product is Good Nights which offers free power from 9.00pm to midnight every day. It has had remarkable success in shifting consumption patterns. We have followed this up with ‘Dream Charge’ which targets EV owners with lower rates overnight. We will keep innovating in this space.

15. We also work hard to protect our most vulnerable consumers. We support, and fully comply with the Consumer Care Guidelines, as a baseline. For those in particular need we have a dedicated ‘Energy Wellbeing’ team, which provides additional support, working with customers to provide advice, set customers up on bespoke payment arrangements to keep on top of debt, and offer direct financial support where needed. We also work with social support agencies to provide wrap around support as difficulties paying for energy is often a symptom of wider issues facing vulnerable customers.

Government’s role in the transition

16. As noted by the consultation paper, New Zealand’s electricity market settings have been extremely successful. New Zealand has achieved a AAA ranking in the World Energy Council’s Energy Trilemma Index across energy security, energy equity and environmental sustainability. We are currently ranked 8th in the world, and expect New Zealand to rise further in global rankings as our decarbonisation journey accelerates.

17. This is built off a well-designed market and abundant natural resources that make us the envy of the world, including:

    a. a well-functioning nodal based market providing accurate investment signals, and avoiding the need for government to steer what investments are made and where;

    b. a mature regulatory regime for network monopolies;

    c. significant existing hydro capacity with the capability of providing renewable firming;

    d. geothermal resource providing valuable baseload renewable capacity; and

    e. abundant on-shore wind and solar capacity.

18. However, New Zealand also faces a number of challenges, many of which are unique to us:

a. Very high renewables penetration, and limited thermal capacity to firm weather dependent generation.

b. No international interconnection, so New Zealand cannot rely on complementary demand or generation profiles between jurisdictions.

c. Peak demand in the morning and evenings that often does not coincide with peak output from intermittent renewables, particularly solar.

d. A self-contained gas market with limited flexibility and declining supply and investment

e. Low population over a relatively large land area.

19. Our unique advantages and challenges mean that many of the interventions implemented overseas are not well suited to New Zealand. In many cases they are unnecessary, solving problems we do not face, and in others they do not make the best use of our natural advantages.

20. We consider that there are four areas government should focus its attention. We consider each of these in the following sections:

a. Supporting a market-led approach to new generation capacity;

b. Addressing barriers to the full range of flexible electricity technologies;

c. Resolving barriers to demand growth; and

d. Supporting consumers in energy hardship, and those most affected by the transition.

Supporting growth in generation capacity

21. There is an impressive pipeline of new generation projects across the industry.[1] Contact Energy alone has plans for more than 6.5TWh of new generation this decade, and together with other existing generators, and new entrants achieving the desired growth in capacity is well within reach.

22. All of this activity is the result of the investment signals in current market settings. This is a remarkable and delicate achievement. Few if any other markets are able to rely on private investment to this extent.

23. We are concerned that some of the interventions considered by the consultation papers risk permanently damaging these incentives, and resulting in a less efficient market, and imposing costs on end users. For that reason we strongly oppose subsidised contracts for difference (CFDs) and feed-in tariffs especially where these favour some types of generation over others such as offshore wind. Both these mechanisms require judgement on expected generation volumes, or

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[1] https://web-assets.bcg.com/b3/79/19665b7f40c8ba52d5b372cf7e6c/the-future-is-electric-full-report-october-2022.pdf, p94

strike price. Given the significant uncertainty it is inevitable that a single decision-maker will get these decisions wrong. It is not worth taking this risk when the market is already delivering.

24. However, there are a number of other actions government should pursue:

    a. Improving the consenting regime so that the sector can more rapidly respond to price signals. The draft National Policy Statement on Renewable Energy Generation (NPS-REG) is a good step in the right direction and needs to be implemented with urgency.

       It is also essential that a fast-track consenting regime is up and running as soon as possible. The regime established under the COVID-19 Recovery (Fast-track Consenting) Act 2020 has ongoing merit, and we support the approach being continued as a permanent feature of resource management.

    b. Providing confidence in the stability of the wholesale market so that developers know what market they are investing in, and can be more certain of returns. This could be achieved by stating that the distortionary interventions canvassed in these papers will not be further explored, and potentially a government policy statement that directs against fundamental changes to the key features of the wholesale market.

    c. Ensuring that the market for flexible electricity continues to evolve to meet the needs of all generators and users. Flexibility services will increase in importance as thermal generation exits, and intermittent renewables penetration increases. The market will continue to commercially evolve to provide services to fill this need, but we support government oversight. If the market does not develop it may be necessary for new flexibility products to be developed, consistent with the recommendations of the Market Development Advisory Group (MDAG).[2]

    d. Stability in the emissions trading scheme and emissions reduction policy. Over the last year this market has been highly volatile, largely off the back of decisions made by government. Greater stability will support investment decisions in renewable technologies.

    e. We support the development of a Renewable Energy Certificate (REC) market, as covered at page 25 of the Transitions Measures Paper. This could be bolstered by government oversight and accreditation of parties issuing RECs. However, we do not consider that a retailer obligation is necessary. We are increasingly seeing industrial and

[2] For example, developing standardised shape products and exploring how to ensure these products have sufficient volume traded.

commercial customers demand these credits, and it is highly likely that the market will develop naturally.

Offshore wind

25. We broadly support the proposed permitting regime for offshore wind. It sets up a regime that allows for investment when offshore wind becomes viable.

26. However, currently offshore wind is not a cost-effective way to grow generation capacity. It is multiples of the cost of onshore wind with a relatively modest increase in output per installed MW. We therefore strongly support the provisions to avoid speculative permits to bank the best sites with no intention to build in the near term.

27. There is no justification for government intervention to encourage offshore wind development before the economics support it. This includes direct government subsidies, risk reduction tools, and interventions that give special treatment, for example on grid connections.

28. We expect that offshore wind will develop naturally over the next 10-20 years as costs come down to be competitive with other forms of generation. Government investment would simply distort market signals and lead to a higher cost system for no benefit to consumers.

29. The consultation paper suggests offshore wind may be a critical part of a decarbonised sector because it more constant and predictable than some other renewables.[3] We disagree. Given the scale of offshore wind developments, the equivalent onshore wind capacity would be spread across multiple projects, likely in different parts of the country. Spreading the assets improves their resilience and also means there is generation across more weather patterns. A diversified portfolio more than compensates for the slight increases in capacity factors for offshore wind. On that basis, focus should begin with fully utilising onshore resources.

Addressing barriers to growth in flexible generation

30. Getting the settings right for flexible electricity capacity is the key challenge for the New Zealand market. This is a challenge all around the world, but is particularly acute here because of the high proportion of renewables, lack of any international interconnection, and concerns around gas flexibility.

[3] https://www.mbie.govt.nz/dmsdocument/26913-developing-a-regulatory-framework-for-offshore-renewable-energy-pdf, p9

31. However, this shouldn't be considered a market design issue. The market is sending out a loud and clear signal to invest in flexibility. Given the generally low barriers to entry, investment would be happening at pace if possible.

32. The lack of growth in flexible electricity supply should be considered a technology problem. While technologies currently exist to meet this need, each one has a number of barriers holding back investment.

33. Figure 3 below shows the range of current flexible technologies and what role they can play in the market. There is a high degree of uncertainty about the best mix of these assets to serve the New Zealand economy. That means it is well suited to the competition of ideas possible in a market, which can adjust based on the most up to date information.

Figure 3: Current flexibility options

	Seconds	Minutes	Intra-day	Inter-day	Weekly+	Seasonal
Hydro	✓	✓	✓	✓	✓	
Pumped hydro	✓	✓	✓	✓	✓	
Demand response[4]	✓	✓	✓	✓	✓	
Lithium-Ion batteries	✓	✓	✓			
Gas or biogas		✓	✓	✓	✓	✓
Coal or biomass			✓	✓	✓	✓

34. Direct government intervention has a high risk of picking the wrong set of assets, resulting in higher prices, less security of supply, and risks displacing private sector investment with government investment at a time where the government faces significant budgetary pressures. Therefore, government should clear the decks of any prospect of government led investment via the NZ Battery Project. This will increase certainty of the market conditions being invested into.

35. The role of government is to ensure that each of these forms of flexibility are viable by removing any barriers currently in place. Below we provide some views on actions government could take to reduce barriers for thermal generation,

[4] We have indicated demand response can meet all time periods, however, this will be dependent on the capabilities of each demand response provider, and some timescales such as weekly+ will be rare.

hydro, batteries, residential demand shifting and commercial and industrial demand response.

Improving settings for thermal generation

36. Thermal generation will have a role to play in the New Zealand electricity market for a number of years. It is one of the best forms of generation for intra-day through to season flexible supply. Retaining thermal in the system beyond 2030 is likely to lead to less total emissions in the New Zealand economy by keeping the cost of electricity low, and having more flexibility to support growth in intermittent renewables.

37. The most significant barriers to any new thermal generation has been the government's target to reach 100% renewable generation by 2030, and the ban on offshore oil and gas exploration. These policies have significantly undermined confidence in the market. Government should now work hard to provide assurances that any new investments will not be undermined again in the future.

38. We also support government keeping a close eye on the development of a flexible gas market. In our experience, access to flexible gas is the main difficulty in operating thermal plant, not the ownership or operation of the assets themselves. There are a number of factors that have exacerbated this risk:

    a. Prolonged under-investment by the gas sector, partly because of hostile policy settings

    b. As baseload thermal exits the market, a larger portion of gas demanded by the electricity sector will need to be flexible. Flexible supply is less attractive for upstream suppliers, making it harder to contract for, or at a much higher price.

    c. Information asymmetries regarding upstream gas supply.

39. Currently there is no flexible gas market of note. Gas is typically supplied on a 'take or pay' basis and we are conservative in our supply agreements to ensure that thermal can play a back-up role. We then face a risk that we have contracted more than is needed. This risk plays out most in wet years when will often be forced to run thermal assets in a loss-making position. To ensure we can cover our long run marginal costs, we need to recover a greater amount in periods where gas is in demand.

40. We are able to partially create flexibility via gas storage, such as the Ahuroa Gas Storage (AGS) facility. However, these storage facilities themselves have considerable capital costs, which are not reflected in short run marginal costs.

41. To solve for gas supply risk, thermal providers have looked to over the counter arrangements, such as swaptions, which reflect long run marginal costs, including fuel costs. We expect that the market will increasingly value these contracts, but we support monitoring from government to ensure that this market is developing as required.

42. Ideally a more flexible gas market would also emerge, and we encourage MBIE to consider ways to support this. This might include a more formal secondary market to support demand response from major gas users, or potentially more gas storage if good sites can be found.

Improving settings for hydro generation

43. As identified by MDAG, hydro is likely to play a major role in providing flexibility into the electricity market. Our system has significant storage, and capacity can be ramped up at short notice.

44. Increasing hydro capacity has been off the agenda for decades, but given the limited flexible electricity options, it may need to be part of the mix. This could include augmenting consent conditions to increase capacity, intra-day flexibility or storage of existing assets, and in some cases building new capacity at a commercial scale, potentially including pumped hydro.

45. We propose that government plays a role in leading the conversation about the future of hydro. This would allow a national debate about the trade-offs between green flexible capacity and the environmental and cultural impacts this may cause.

46. We do not support direct government investment in hydro, but national direction to consenting agencies and local interest groups could play a vital role.

Improving settings for lithium-ion batteries

47. Lithium-ion batteries are likely to play a key role in meeting demand for short-term flexibility. This technology has matured rapidly, and can be installed at pace.

48. However, a quirk in the way the wholesale market operates means batteries are not rewarded fully for the capability they bring to the market. That means that less battery capacity will be installed than is optimal, increasing the risk of system security issues.

49. The Electricity Authority recently implemented real time pricing (RTP) into the New Zealand electricity market. This means that real time prices from the System Operator are now final and there are no longer ex post prices.

50. Currently RTP dispatch is scheduled on a 5-minute basis, but prices are calculated as the average over the entire 30 minute trading period. This method under-compensates capacity that can respond to short term demand spikes, such as hydro, batteries, and some demand response.

51. The optimal use of technologies like grid scale batteries is to turn on for very short periods to meet the highest spikes. That may mean operating for only 5-10 minutes at a time when the market demands it the most. 30-minute averaging flattens the value available to these technologies, and will weaken incentives to deploy them.

52. We recommend that the Electricity Authority considers ways to better align financial incentives with the physical operation of the market. We expect that this will have a material positive impact on the whole market. The wholesale market will be increasingly defined by higher volatility leading to short term price spikes.[5] More accurate pricing would encourage more competition over these spikes ultimately bringing prices down.

53. In Australia this has been achieved by calculating prices on a 5-minute basis. In their final decision the Australian Energy Market Commission (AEMC), noted:

> By aligning the financial incentives for participants with the physical operation of the market, five minute settlement will more accurately reward those who can deliver supply or demand side responses when they are needed by the power system. In contrast, 30 minute settlement provides an incentive to respond to expected 30 minute prices, rather than the five minute dispatch price. This pricing distortion leads to generator and demand responses that can occur up to 25 minutes after they are required by the power system.
>
> Aligning dispatch and settlement at five minutes and creating an improved price signal also provides the right incentives for innovation and investment. In particular, efficient investment and innovation in an appropriate amount of flexible generation and demand side technologies. The expected result over time is a more efficient mix of generation assets and demand response technologies leading to lower supply costs. This will benefit consumers as reduced wholesale electricity costs flow through to lower retail prices.[6]

54. Our own analysis supports this conclusion. We find a material improvement in the return for grid scale batteries with 5-minute pricing, suggesting that this change would encourage much more fast start flexible capacity into the market.

55. We appreciate that this would be a material change and there may be other options to consider. But given its importance in incentivising flexible capacity we recommend that government makes it a priority for the Electricity Authority to consider how to more accurately reward the capability of very fast start capacity generation.

56. We also consider that the proposal to subsidise domestic batteries would be a poor outcome for consumers. This is because grid scale batteries are significantly more efficient than domestic batteries. If a domestic subsidy was implemented it would be prioritising a less efficient technology, ultimately reducing the efficiency of the system, and raising costs for consumers.

Improving the settings for residential load shifting

57. Through time of use plans such as Good Nights we have been able to start to shift demand away from peaks, reducing demand on generation and network capacity. We expect this to be an area of growth in the coming years.

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[5] https://www.ea.govt.nz/news/eye-on-electricity/spot-market-price-volatility-in-may-2023/

[6] https://www.aemc.gov.au/sites/default/files/content/97d09813-a07c-49c3-9c55-288baf8936af/ERC0201-Five-Minute-Settlement-Final-Determination.PDF, pii

58. A significant part of the value of shifting domestic load out of the peaks comes from the impact on network capacity. Ultimately, some form of market to price this benefit should emerge, however network pricing should also reward shifting out of peaks.

59. We support the work underway by the Electricity Authority to reform distribution pricing. In particular we would like to see EDBs move faster to tariffs that reflect costs, and only charge a variable rate during peaks. The latest round of scorecards on EDB pricing showed some improvements, but this change is happening too slow, and may mean larger network upgrades than necessary if there is insufficient incentive to load shift for consumers.

Improving settings for commercial and industrial demand response

60. Through our subsidiary Simply Energy we have one of the most sophisticated demand side flexibility (DSF) programs for commercial and industrial (C&I) customers in New Zealand. Simply works with customers at over 60 predominantly industrial sites, across a range of sectors. Most of this flexibility is offered into the reserves markets because of structural barriers in the energy market, and limited opportunities to support transmission and distribution networks.

61. The C&I demand response market is primed for significant growth. DSF thrives in more volatile markets like we are starting to see in New Zealand. Price volatility creates opportunities to reduce load for short periods of time to take advantage of high spot market prices.

62. The best way to grow C&I DSF is to unbundle the retail and flexibility markets. That would allow energy and flexibility services to compete on their own merits. A customer can choose the cheapest energy offering, and then separately choose the flexibility trader offering the best service to meet their needs. This would maximise competition and innovation amongst retailers for energy supply, and flexibility traders for the controllable load.

63. As noted in the AEMC Reliability Frameworks Review, a bundled approach can lead to less DSF being offered into the market:

> *Retailers are incentivised to utilise demand response where it is efficient to do so; however, they may opt not to if they lack the experience or the organisational expertise to utilise wholesale demand response or do not expect to recover the costs of engaging with a consumer to provide wholesale demand response. In addition, retailers have other ways of managing wholesale electricity market price risks, such as financial contracts and vertical integration.*[7]

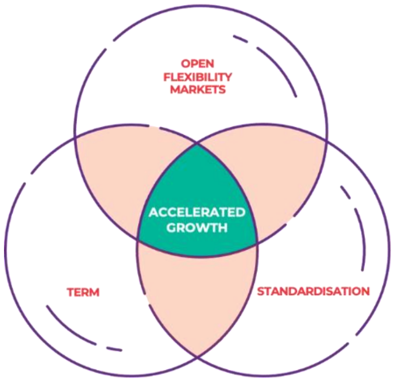
64. However, it is currently not viable to operate as an independent flexibility trader in the energy market for three key reasons, also shown in figure 4:

[7] https://www.aemc.gov.au/sites/default/files/2018-07/Final%20report_0.pdf, p53

a. Lack of **open flexibility markets**. Currently a flexibility trader must establish an agreement with the customer's energy retailer to gain access to the value of reducing load. Commercial incentives make it unlikely that these agreements will result in an optimal outcome under current market settings.

b. Insufficient **term** – to make demand side flexibility arrangements commercially viable they need a longer term (5 years +) than is common in retail contracts (1-3 years, except for the very largest customers like Tiwai or NZ Steel). Unlike residential flexibility, commercial and industrial DSF requires bespoke arrangements to integrate with or upgrade a customer's existing control systems. That means there are significant set-up costs that are unique to each DSF agreement. DSF returns are also often very volatile, taking advantage of peak market prices, whereas customers are seeking a consistent cash-flow. A longer-term contract allows the flex trader to take the volatility risk, and be more certain of a sufficient return.

Figure 4: Key features required for commercial and industrial demand side flexibility to emerge at scale



c. Lack of **standardisation**. without centralised markets, flexibility traders will need to develop customised software and rules for each commercial agreement, determining how and when demand-side flexibility will be invoked, measured and compensated. The costs associated with bespoke development for each party's requirements would make offering flexibility services uneconomical.

65. These three effects all work together to limit DSF. Negotiating an arrangement to supply flexibility services to a retailer may be possible in some circumstances. However, the flex trader has no guarantee that when the customer churns to a new retailer, that the new retailer will be interested in continuing the arrangement (term issue). Even if the new retailer does want to continue, they may have different requirements and systems, potentially making much of the original investment by the flex trader redundant (standardisation issue). Given these risks it is hard to justify the up-front investment costs, so few deals make it past the starting gates.

66. Current and proposed arrangements are not sufficient to address these barriers.

- **Dispatch Notifications (DNx):** DNx was introduced in April 2023 to enable retailers and flexibility traders to offer MW reductions into the wholesale market, and be dispatched like generation. While we support this step, it doesn't address any of the market access, term or standardisation challenges discussed above. In practice, Simply have found it more effective to be a price taker and just responding to the price in real time.

- **Demand Side Flexibility (DSF) Tariffs:** The December 2022 MDAG consultation focuses on retailer DSF Tariffs as the key mechanism to drive the uptake of energy market DSF. This means lower prices for consumers willing to have some of their load managed, or detailed variable rates to reward the customer managing the load themselves.

  However, we do not believe this is a practical solution for the majority of C&I customers. Few customers have the willingness or capacity to actively manage their electricity use or expose themselves to the volatility of the wholesale market. Instead they expect the retailer to manage the volatility risk. This means the customer's price signal is muted compared to the volatility experienced in the wholesale market and is often not a big enough signal to warrant the operational impact from regular load shifting.

- **Multiple Trading Relationships (MTR):** MTR allows more than one retailer to offer services on the same ITP. This has been proposed as a method of enabling demand response, for example, one party could retail electricity for the controllable refrigeration load at a large meat processing site, and another party to retail electricity for the rest of the load behind the same ICP.

  For retailers, being able to control part of the load doesn't overcome the term issue described above. For specialist flexibility traders, MTR relies on them also becoming retailers in order to access the wholesale value. In a small market like New Zealand this requires significant investment from a flexibility trader in an area where it may have no existing business systems.

67. Further enhancements to the wholesale market are necessary to support larger uptake of demand response. One option is to implement a market-based demand response mechanism which would treat demand response in a similar way to generation capacity, rewarding it directly if dispatched. This sort of mechanism has been implemented in Australia[8] and recently approved for implementation in the UK.[9] As noted in the UK, this mechanism:

> will remove a barrier to customers offering flexibility, and hence should increase participation and the level of effective competition the demand side can bring.[10]

68. We have provided details on this mechanism and how it addresses the challenges in the New Zealand market in a number of recent submissions:

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[8] https://aemo.com.au/en/initiatives/trials-and-initiatives/wholesale-demand-response-mechanism
[9] Ofgem decision P415 'Facilitating Access to Wholesale Markets for Flexibility Dispatched by VLPs' | Ofgem
[10] https://www.elexon.co.uk/documents/change/modifications/p401-p450/p415-final-modification-report-public/, p6

a. Contact Energy Submission on the Electricity Authority's Wholesale Market Review - December 2022

b. Contact Energy submission on MDAG consultation paper - March 2023

c. Contact Energy submission to the Electricity Authority on Ensuring an Orderly Thermal Transition - July 2023

Growing demand

69. All forecasts of New Zealand's energy sector show a significant growth in demand for electricity. This is driving investment signals that the market is acting upon.

70. However, there remains significant uncertainty about where, how and when demand will begin to increase. Certain government actions can support this transition, so that it happens as smoothly as possible. In the below sections we highlight the importance of the Emissions Trading Scheme (ETS), and connection costs.

Stability is needed in the Emissions Trading Scheme

71. We encourage government to improve the stability of the Emissions Trading Scheme as the primary tool to encourage commercial decarbonisation decisions. Over the last year this market has been highly volatile, largely off the back of decisions made by government.

72. To improve stability, it may be appropriate to separate out the operation and parameters of the ETS auctions and markets into an independent Crown Entity, as is common for operational functions across government. This could be coupled with more strict rules around how and when changes can be made. The end goal should be for a politically independent function with broad public support, similar to the Reserve Bank.

73. We'd also support the introduction of a carbon dividend, particularly for lower income households. This would allocate some of the revenue from ETS auctions back to consumers to offset the cost impact, while retaining the price incentive to choose lower emitting products and services. This sort of mechanism would provide greater long-term social license for the ETS, and make it more robust against criticism that it increases the cost of living.

The costs of getting connected to the network can be a barrier

74. We also recommend that government addresses the concerns that we, and many others have raised about the costs and process for getting new and upgraded connections to the network. We consider that commercial and industrial process heat conversion should be the priority of this work as they are likely to be the largest source of new demand and greatest contributors to the country's decarbonisation goals.

75. We agree with MBIE that:

> In the majority of cases distribution businesses have few regulatory incentives to put downward pressure on costs passed through to the customer as upfront connection charges. The connecting customer has limited ability to shop around for a lower cost solution, increasing the risk that connection costs may be inefficiently high.[11]

76. This is the result of a regulatory regime for connecting customers that does not provide strong incentives for EDBs. This is a material problem that will hold back the decarbonisation of the economy.

77. We define the problem as having four components:

    a. In some cases **customers may be charged for costs not necessary for their connection**. An EDB can include wider network upgrades into a connection cost as there are no requirements to be transparent about what is included in a connection, or any need to choose the lowest cost option for a customer.

    For example, an EDB may 'overbuild' a connection to provide additional capacity for a second mover on the same part of the network. Many EDBs have now implemented a mechanism for a second mover to compensate the first mover. However, this means there is still a significant cost and risk that the first mover is wearing for no benefit to themselves.

    The current regime also permits EDBs to charge a connecting customer for more general upgrades to the network, for example to meet increased demand across a number of customers.

    b. **EDBs are exposed to revenue risk for overbuild, even when it is efficient**. If an EDB builds more than its capex allowance it is subject to the IRIS disincentive rate. This may incentivise them to find other sources of funding for overbuild, such as through connection costs.

    However, we also recognise that a new connection often provides an opportunity to do wider network upgrades at a lower cost than if the EDB were not already undertaking the connection work. In many cases it will be efficient to bring forward upgrades planned for the future, but not accounted for in the capex allowance in the current regulatory period. Under the current settings, these are broadly three things that can happen: the overbuild costs are charged to the connecting customer, reducing their incentive to decarbonise; the work is undertaken in two stages, raising total costs for consumers; or the EDB undertakes the work, adds it to the RAB and absorbs the IRIS disincentive rate, harming their incentive to invest efficiently.

[11] https://www.mbie.govt.nz/dmsdocument/26909-measures-for-transition-to-an-expanded-and-highly-renewable-electricity-system-pdf, para 230.

c. **EDBs do not have incentives to offer interruptible connections.** Most commercial and industrial customers require a connection with redundancy if there is an outage at key points in the network. This is commonly referred to as an n-1 connection. However, many businesses seeking to decarbonise have an on-site source of energy, such as a coal boiler that they can use to continue operations if there is an outage. This means they do not need to have a redundant electricity supply. This is called a ‘non-firmed connection’, and can be significantly lower cost than a connection with redundancy.

   Not all EDBs offer this sort of connection, increasing costs to decarbonise.

d. **The connections process is opaque and inconsistent**, as noted in the DETA report referenced by MBIE.

78. We propose four changes to the regulatory regime to address these problems:

1. Require that EDBs charge customers the minimum cost to connect

79. This requirement could be added to the Electricity Code. To enforce it there should be the ability for a connecting customer to request an independent audit of the proposed connection cost, and the ability to appeal to the Rulings Panel if there is a dispute.

2. Support EDBs to undertake efficient over-build.

80. Ideally the costs of any overbuild should be attributed to the party that benefits from it.

81. For upgrades that benefit existing customers they should be added to the regulatory asset base (RAB), and charged to customers appropriately. In these cases it may be appropriate to refund some or all of the IRIS disincentive if the EDB can show that the overbuild was efficient and lowered costs for consumers in the long run.

82. For overbuild for second movers there is a policy choice on who to charge. Three broad options are set out in figure 5 below:

Figure 5: Options for funding efficient overbuild for second movers

1. Charge the first mover (status quo)	2. Spread cost amongst all consumers by adding to RAB	3. Government funds cost of overbuild and is repaid by second mover
Pros: • Larger customers may be more equipped to absorb these costs, and limits impacts on residential consumers Cons: • Will continue to halt many decarbonisation projects. • May also raise total costs to residential consumers as the network is less utilised.	Pros: • Spreads costs so impact on any one consumer is small • Does not distort economic activity • Likely more decarbonisation will occur Cons: • Raises costs for residential consumers	Pros: • Does not distort economic activity • Likely small cost to government as costs repaid by second mover Cons: • May be challenging to administer

83. Option 1 has the least benefit to the economy and the climate. We therefore support either option 2 or 3. Under option 2 there may need to be similar mechanisms as discussed in paragraph 81 above to ensure that EDBs remain whole.

84. As noted by MBIE, option 2 "could lead to costs being borne by those who can least afford it".[12] We anticipate that these costs are likely very small, but if this is a major concern then option 3 may be the best choice.

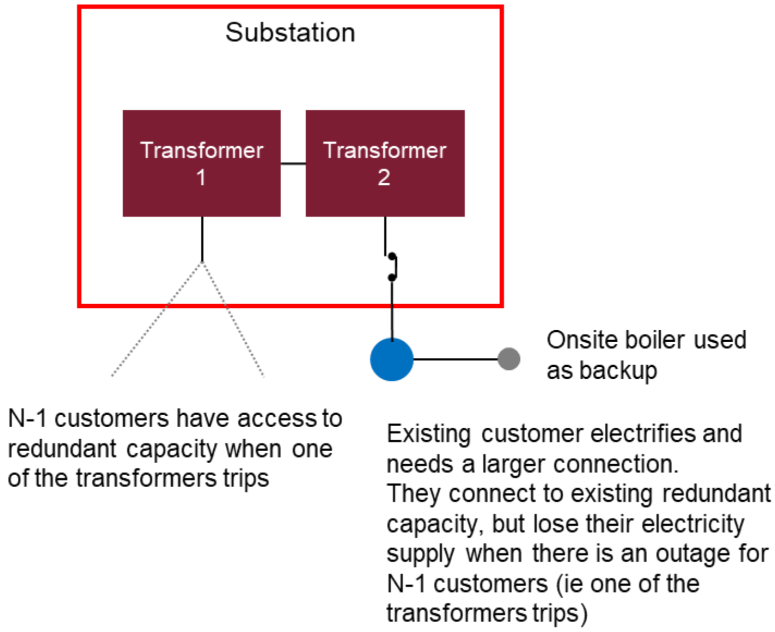
3. Require EDBs to offer non-firmed connections

85. As noted above, offering an interruptible connection will often be the most efficient way to decarbonise many process heat users. This can be significantly cheaper than a standard connection. We recommend that the Electricity Code requires EDBs to offer this form of connection where requested.

86. In many cases these connections will utilise existing redundant capacity. Figure 6 below shows a stylistic example of how this can work.

[12] Para 242

Figure 6: Simplified example of a non-firmed connection



87. This is an efficient use of assets. But it creates complexity for the EDB who must set up systems and processes to ensure that the redundant capacity is available for customers with n-1 level of security in the event of an outage. It is reasonable for the connecting party to pay these additional costs, but this simply makes an EDB whole, it does not provide them any incentive to reward socially efficient use of their assets.

88. We recommend that the Commerce Commission considers allowing EDBs to partially double-recover assets that are used twice. Taking the example in figure 6 above, it may be appropriate for an EDB to charge customers the full cost of an n-1 connection, but then allow for some (say 5-10%) of the cost of the redundant capacity to also be charged to the non-firmed connection. This appears consistent with how a workably competitive market would operate if a secondary use of an existing asset is found.

4. Address process issues by putting in place a dedicated access regime

89. We fully support the discussion at paragraphs 243 – 245 of the consultation paper, and the proposal in question 35 to apply the pricing principles in Part 6 of the code to new load connections.

90. However, we do not consider that this change on its own will sufficiently address the current challenges getting decarbonisation projects connected to the network. This change should be complemented with the other three recommendations above.

Supporting consumers through the transition

91. We support the work undertaken by Sapere on behalf of Electricity Networks Aotearoa (ENA) that shows the total household energy cost will reduce through the transition.[13] This is largely because electricity is a cheaper form of energy than petrol for transport.

92. However, we expect that the road to this ideal outcome will be bumpy and some consumers will find it harder than others. Through all this it is important that trust in electricity as a clean and affordable source of energy is maintained so that consumers do not become wary of switching from gas and petrol.

93. We make two key recommendations to support consumers through the transition:

    a. Better targeting of the Winter Energy Payment. This subsidy currently provides over half a billion dollars annually to all beneficiaries, including superannuitants. It does not assess for need so significant portions of it go to consumers who are not in hardship.

       We know that better targeting is possible. During the energy crisis in Europe last winter targeted support payments were made to those most in need. For example, in the UK the £900 'Cost of Living Payment' was means tested, and in France €100-200 was provided to those with the lowest incomes.

    b. Managing the impact of lines company price increases, while maintaining an appropriate level of financeability. As noted by the Commerce Commission, there is likely to be a significant increase in revenues from 2025 for the EDBs and Transpower. This is largely driven by changes to interest rates and inflation.

       We support an appropriate return to the lines companies to fund necessary investment. However, as a retailer with responsibility for the customer relationship we are also aware of the impact this could have on consumers.

       To reduce this risk the Commission should continue to adjust the revenue path to minimise price shocks, while taking into account the financeability of the lines companies. If ensuring financeability means that there must be price shocks then MBIE should consider ways to support consumers through this period.

[13] https://www.ena.org.nz/resources/electrification-of-nzs-energy-needs/document/1231

Attachment 1: Summary of Recommendations

Supporting growth in generation capacity

1. Improve the consenting regime by completing the re-drafting of the NPS-REG and putting in place a functioning fast-track mechanism.
2. Provide confidence in the stability of the wholesale market by ceasing work on distortionary interventions canvassed in these papers, such as government backed CFDs or feed-in tariffs.
3. Monitor the development of flexible electricity supply contracts.
4. Consider ways to encourage the development of a flexible gas supply market.
5. Consider government accreditation and regulation of Renewable Energy Certificates.

Improving settings for thermal generation

6. Provide assurances that new investments in gas supply will not be undermined
7. Monitor the development of over the counter contracts that appropriately compensate for the capacity offered by thermal generation.

Improving settings for hydro generation

8. Lead a national debate about the future role of hydro generation.

Improving settings for lithium-ion batteries

9. Considers ways to better align financial incentives with the physical operation of the market, such as 5-minute pricing in the wholesale electricity market.
10. Do not subsidise domestic batteries, which are less efficient than grid scale batteries.

Improving settings for residential load shifting

11. Accelerate the transition of distribution pricing to reflect costs and only charge variable rates during system peaks.

Improving settings for commercial and industrial demand response

12. Implement a market-based demand response mechanism to directly reward capacity offered into the wholesale market.

Growing demand

13. Improve stability of the emissions trading scheme by:
    a. Separate out the operation and parameters of the ETS auctions into an independent Crown Entity.
    b. Implementing a carbon dividend, particularly for lower income households
14. Address the costs of decarbonisation projects getting connected to the network by:

a. Requiring EDBs to only charge customers the minimum cost to connect
b. Supporting EDBs to undertake efficient overbuild at the same time as a connection is made.
c. Require EDBs to offer non-firmed connections
d. Consider putting in place a dedicated connection regime into the Electricity Code, similar to the Part 6 access regime.

Supporting consumers through the transition

15. Improve the targeting of the Winter Energy Payment to better support households in most need.
16. Managing the impact of lines company price increases, while maintaining an appropriate level of financeability for the lines companies.

Attachment 2: Answers to consultation questions

Measures for Transition to an Expanded and Highly Renewable Electricity System

#	Consultation question	Contact Energy Response
1	Are any extra measures needed to support new renewable generation during the transition? Please keep in mind existing investment incentives through the energy-only market and the ETS, and also available risk management products. Any new measures should add to (and not undermine or distort) investment that could occur without the measures.	There is a significant amount of investment already underway. Contact Energy alone has well advanced plans for up to 6.5TWh of new generation this decade alone. We fail to understand what problem government interventions such as CfDs and feed-in tariffs would solve. There is a real risk that it will result in government picking winners (eg offshore wind) and distorting investment signals, resulting in increased costs for consumers. However, as highlighted at pages 6-8 of our submission we see a number of improvements government could make to support the investment being made by the sector: - Improving the consenting regime so that the sector can more rapidly respond to price signals - Maintain stability in wholesale market settings so that we know what environment we are investing into - Monitor the market for flexibility services - Stability in emissions reduction policy - Supporting the growth of renewable energy certificates.
2	If you think extra measures are needed to support renewable generation, which ones should the government prioritise developing and where and when should they be used? What are the issues and risks that should be considered in relation to such measures?	
3	If you don’t think further measures are needed now to support new renewable generation, are there any situations which might change your mind? When and why might this be?	

<table>
<tr><th>#</th><th>Consultation question</th><th>Contact Energy Response</th></tr>
<tr><td>4</td><td>Do you think measures could be needed to support new firming/dispatchable capacity (resources reliably available when called on to generate)? If yes, which kind of measures? What needs do you think those measures could meet and why?</td><td rowspan="2">There are strong and growing investment signals for firming capacity. Government should focus efforts on reducing barriers to investment in these technologies as we discuss at pages 8-16. In particular:
- Removing the uncertainty of government direct investment via the NZ Battery Project
- Remove 100% renewable targets that cast a cloud over new thermal generation
- Monitor the development of the market for flexible electricity
- Consider if government has a role to play in enabling greater hydro capacity
- Implementing 5-minute pricing to properly reward capacity such as batteries that can respond to fast changes in demand
- Accelerate the EAs work to reform distribution pricing.
- Implement a market-based demand response mechanism</td></tr>
<tr><td>5</td><td>Are any measures needed to support storage (such as battery energy storage systems or BESS) during the transition? If yes, what types of measures do you think should be considered and why?</td></tr>
<tr><td>6</td><td>If you answered yes to question 4 or 5 above, should the support be limited to renewable generation and renewable storage technologies only or made available across a range of other technologies?

Keep in mind that fossil fuels are generally the cheapest option for firming, though this may change over time as renewable options (particularly batteries) become more efficient and affordable.</td><td></td></tr>
<tr><td>7</td><td>If you answered yes to question 6 above, what are the issues and risks with this approach? How could these risks and issues be addressed?</td><td></td></tr>
<tr><td>8</td><td>Are any measure(s) needed to support existing or new fossil gas fired peaking generation, so as to help keep consumer prices affordable and support new renewable investment?</td><td>In our experience, access to flexible gas is the main difficulty in operating thermal plant, not the ownership or operation of the assets themselves.

We consider that as part of the next phase of the Gas Transition Plan government should</td></tr>
</table>

#	Consultation question	Contact Energy Response
9	If you answered yes to question 8 above, what measures should be considered and why? What are the possible risks and issues with these measures?	undertake a thorough analysis of the market for the supply of flexible gas and consider if there are any ways that government can improve these settings. Any interventions should avoid material distortions to price signals. We consider that these signals are the best way to ensure that thermal generation exits the market at the correct time.
10	If you answered yes to question 8 above, what rules would be needed so that fossil gas generation remains in the electricity market only as long as needed for the transition, as part of phase down of fossil gas?	
11	Are there any issues or potential issues relating to gas supply availability during electricity system transition that you would like to comment on?	
12	Do you agree that specific measures could be needed to support the managed phasedown of existing fossil fuel plants, for security of supply during the transition?	In 2021 Contact Energy released the paper "Crafting a path for New Zealand's 100% renewable electricity market". This paper considered the risk of 'disorderly exit' of thermal. Our preferred option was a 'Thermalco' that would own all thermal assets and manage their phased retirement and have sufficient scale to manage flexible gas supply.
13	If you answered yes to question 12 above, what measures do you think could be appropriate and why? What conditions do think you should be placed on plant operation? For example, do you have any views on whether there should be a minimum notice period for reductions in plant capacity, and/or for placing older fossil fuel plant in a strategic reserve?	
14	If you answered yes to question 12 above, what are the issues and risks with these measures and how do you think these could be addressed?	
15	What types of commercial arrangements for demand response are you aware of that are	

<table>
<tr><th>#</th><th>Consultation question</th><th>Contact Energy Response</th></tr>
<tr><td></td><td>working well to support industrial demand response?</td><td rowspan="3">There have been a few long-term energy supply arrangements with flexibility built in for large electrification projects, such as Open Country. There have also been some very large industry hedge arrangements with knock-out periods such as NZ Steel.

However, beyond this there is very little demand response developing in the commercial and industrial space outside of large individual bespoke contracts.

We do not consider that the shaped hedge product proposed by MDAG will have a material impact on DSF volumes. There are only a few customers willing to actively manage their electricity use in a way that would take advantage of such a product.

We support a market-based demand response mechanism that allows demand response providers to be rewarded by the wholesale spot market in the same way as distribution is. We describe this in more detail at pages 13-16</td></tr>
<tr><td>16</td><td>What new measures could be developed to encourage large industrial users, distributors and/or retailers to support large-scale flexibility?</td></tr>
<tr><td>17</td><td>Do you have any views on additional mechanisms that could be developed to provide more information and certainty to industry participants?</td></tr>
<tr><td>18</td><td>Do you agree that the key competition issue in the electricity market is the prospect of increased market concentration in flexible generation, as the role of fossil fuel generation reduces over time?</td><td>We agree that this is possible, but it is not certain. We support monitoring before any action is taken.</td></tr>
<tr><td>19</td><td>Aside from increased market concentration of flexible generation, what other competition issues should be considered and why?</td><td></td></tr>
<tr><td>20</td><td>What extra measures should or could be used to know whether the wholesale electricity market reflects workable competition, and if necessary, to identify solutions?</td><td>There is already a high degree of oversight on the wholesale electricity market. Specific trading rules such as the High Standards of Trading Conduct, and the Undesirable Trading Situation provide ongoing oversight. The Electricity Authority has also undertaken a thorough review of the market as part of the Wholesale Market Review.</td></tr>
<tr><td>21</td><td>Should structural changes be looked at now to address competition issues, in case they are needed with urgency if conduct measures prove inadequate?</td><td>We see considerable risk of signalling intervention before it is necessary. It is uncertain that these measures will be needed, and even less likely that they will ever be needed urgently.</td></tr>
<tr><td>22</td><td>Is there a case for either vertical separation measures (generation from retail) or horizontal market separation measures (amending the</td><td>We do not consider that there is sufficient evidence for these measures.</td></tr>
</table>

#	Consultation question	Contact Energy Response
	geographic footprint of any gentailer) and, if so, what is this?	ERANZ released a report from Cognitus on the benefits of vertical integration in 2021. This is included in their submission to this consultation and remains relevant to this question.
23	Are measures needed to improve liquidity in contract markets and/or to limit generator market power being used in retail markets? If yes, what measures do you have in mind, and what would be the costs and benefits?	The over-the-counter hedge market is becoming increasingly sophisticated, with longer term hedges and more sophisticated products such as caps. We expect it will evolve to meet needs for flexible electricity supply. We support government monitoring to ensure that this is happening at the pace required.
24	Should an access pricing regime be looked at more closely to improve retail competition (beyond the flexibility access code proposed by the Market Development Advisory Group or MDAG)?	No. An access regime would be regulatory over-reach given that no clear problem has been identified. It would pose a risk that it undermines the effectiveness of the spot market and could harm incentives to invest in flexible capacity.
25	What extra measures around electricity market competition, if any, do you think the government should explore or develop?	We consider this has already been sufficient traversed in the Electricity Price Review
26	Do you think a single buyer model for the wholesale electricity market should be looked at further? If so, why? If not, why not?	No, this would undermine the incentives of the spot market and likely lead to less generation being built, and ultimately less reliable electricity supply.
27	Do you consider that the balance of risks between investing too late and too early in electricity transmission may have changed, compared to historically? If so, why?	
28	Are there any additional actions needed to ensure enough focus and investment on maintaining a resilient national grid?	
29	Do you agree we have identified the biggest issues with existing regulation of electricity distribution networks?	

#	Consultation question	Contact Energy Response
30	Are there pressing issues related to the electricity distribution system where you think new measures should be looked at, aside from those highlighted in this document? How would you prioritise resolving these issues to best enable the energy transition?	
31	Are the issues raised by electricity distributors in terms of how they are regulated real barriers to efficient network investment? Please give reasons for your answer. Is there enough scope to address these issues with the current ways distributors are regulated? If not, what steps would you suggest to address these issues?	
32	Are there other regulatory or practical barriers to efficient network investment by electricity distributors that should be thought about for the future?	
33	What are your views on the connection costs electricity distributors charge for accessing their networks? Are connection costs unnecessarily high and not reflective of underlying costs, or not? If they are, why do you think this is occurring?	We are concerned that the incentives for new connections are not well aligned to the interests of consumers. We have seen a number of cases where costs to connect appear unnecessarily high.
34	If you think there are issues with the cost of connecting to distribution networks, how can government deliver solutions to these issues?	We provide some detailed proposals at pages 14-18 in the body of our submission.
35	Would applying the pricing principles in Part 6 of the Code to new load connections help with any connection challenges faced by public EV	Yes, we consider that this would be a valuable improvement. However, this is unlikely to be sufficient on its own.

#	Consultation question	Contact Energy Response
	chargers and process heat customers? Are there other approaches that could be better?	
36	Are there any challenges with connecting distributed generation (rather than load customers) to distribution networks?	
37	Are there different cost allocation models addressing first mover disadvantage (when connecting to distribution networks) which the Electricity Authority should explore, potentially in conjunction with the Commerce Commission?	We provide some detailed proposals at pages 16-20 in the body of our submission.
38	Should the Electricity Authority look at more prescriptive regulation of electricity distributors' pricing? What key things would need to be looked at and included in more prescriptive pricing regulation?	We would like to see distributors move to only having variable prices during peak periods. There are moves in this direction from some EDBs, but for others it is a very slow path. More prescriptive rules advancing this transition would encourage more dynamic load management at a retail level.
39	Do current arrangements support enough co-ordination between the Electricity Authority and the Commerce Commission when regulating electricity distributors? If not, what actions do you think should be taken to provide appropriate co-ordination?	
40	Will the existing statutory objectives of the Electricity Authority and Commerce Commission adequately support key objectives for the energy transition?	We are comfortable with the current objectives. We consider that they encompass sustainability already. However, some more specific direction may help to avoid any doubt (see Q43 below)
41	Should the Electricity Authority and/or the Commerce Commission have explicit objectives relating to emissions reduction targets and plans set out in law? If so, • should those objectives be required to have	

#	Consultation question	Contact Energy Response
	equal weight to their existing objectives set in law? • Why and how might those objectives affect the regulators' activities?	
42	Should the Electricity Authority and/or the Commerce Commission have other new objectives set out in law and, if so, which and why?	
43	Is there a case for central government to direct the Commerce Commission, when dealing with Electricity Distributors and Transpower, to take account of climate change objectives by amending the Commerce Act 1986 and/or through a Government Policy Statement (GPS)?	We support greater government direction to the Commerce Commission to take account of climate change objectives.
44	If you answered yes to question 43, please explain why and indicate: • What measures should be used to provide direction to the Commerce Commission and what specific issues should be addressed? • How would investment in electricity networks be impacted by a direction requiring more explicit consideration of climate change objectives? Please provide evidence.	Direction to take account of climate change objectives is critical to ensure that sufficient electricity lines are built to support an electrified economy. We consider that a Government Policy Statement is sufficient to achieve this outcome. Wider legislative reform has a risk of creating disruption to an otherwise well-functioning regulatory regime at a critical time. Several years of uncertainty will not be conducive to necessary investment.
45	Would government setting out the future structure of a common digital energy infrastructure (to allow trading of distributed flexibility) support co-ordinated action to increase use of distributed flexibility?	Ensuring standardisation of market processes will benefit all market participants, EDB's; Retailers, TSO, and flex traders – and will be critical to ensure distributed flexibility is developed at scale. We note there are already a number of active workstream's looking to solve this challenge and we support any government support for these programmes.
46	Should central government see how demonstrations and innovation to help inform how	We are supportive of government providing more resourcing to accelerate the existing workstreams being undertaken by industry would be beneficial.

#	Consultation question	Contact Energy Response
	trade of flexibility evolves in the New Zealand context, before providing direction to support trade of distributed flexibility? If yes, how else could government support the sector to collaborate and invest in digitalisation now?	The provision of stand-alone flexibility services requires digitalisation. As we note on page 13, we believe any measures government take to unbundle retail and flexibility markets would result in increased development of flexibility services by industry and therefor, in digitisation.
47	Aside from work already underway, are there other areas where government should support collaboration to help grow and develop flexibility markets and improve outcomes? If yes, what areas and actions are a priority?	We recommend increased focus on utilising flexibility services as a non-network solution. Things that would support that include arms-length rules for non-network solutions, development of a distribution system operator (DSO), requirements on distributors to consider non-network solutions for investments above a certain threshold, well funded trials that support both the network and the demand side providers. We are supportive of the innovation fund that has been created and is being managed by Ara Ake and believe this is the right vehicle for supporting investment and collaboration.
48	Could co-funding for procurement of non-network services help address barriers to uptake of non-network solutions (NNS) by electricity distributors?	Yes, we consider that this is needed to kick start the market. This needs to fund both EDBs and flex trader participation. Developing Non-network solutions require EDB's to have a high level of confidence that the Demand Response will be able to be developed and will respond to their signals. Improving the market settings for Demand Response to incentivise this to be built in advance of any need for NNS will likely greatly increase the uptake of NNS through increasing EDBs confidence that it can be developed at scale.
49	Would measures to maximise existing distribution network use and provide system reliability (such as dynamic operating envelopes) help in New Zealand? If yes, what actions should be taken to support this?	
50	What do you think of the approaches to smart device standards and cyber security outlined in this document? Are there other issues or options that should be looked at?	

#	Consultation question	Contact Energy Response
51	Do you think government should provide innovation funding for automated device registration? If not, what would best ensure smart devices are made visible?	
52	Are extra measures needed to grow use of retail tariffs that reward flexibility, so as to support investment in CER and improved consumer choice and affordability?	No. We work hard to find consumer tariffs that reward flexibility and are attractive to customers. For example we have implemented good nights, which provides free power from 9.00am to midnight every night and has had huge success in shifting load. Existing incentives are sufficient for innovations in load shifting to continue to grow.
53	Should the government consider ways to create more investment certainty for local battery storage? If so, what technology should be looked at for this?	We recommend that the Electricity Authority considers ways to better align financial incentives with the physical operation of the market, such as 5-minute pricing in the wholesale spot market. We cover this in more detail at pages 11-12.
54	Should further thought be given to making upfront money accessible to all household types, at all income levels, for household battery storage or other types of CER?	No. Grid scale batteries are a more efficient way of meeting load shifting needs. Domestic subsidies will simply result in a less efficient mix of assets in the market, at a higher overall cost to consumers and taxpayers.
55	Should government think about ways to reduce 'soft costs' (like the cost of regulations, sourcing products, and upskilling supplier staff) for installing local battery storage with solar and other forms of CER/DER storage? If so, what technology should be looked at?	
56	Is a regulatory review of critical data availability needed? If so, what issues should be looked at in the review?	We do not consider that there is currently a significant problem worth regulatory attention.
57	What measures do you consider the government should prioritise to support the transition?	The key priority should be on resolving barriers to available flexible generation and demand response technologies, as well as reducing barriers to demand growth, like the costs of connecting to the network.

#	Consultation question	Contact Energy Response
58	Are there gaps in terms of information co-ordination or direction for decision-making as we transition towards an expanded and more highly renewable electricity system and meeting our emissions goals? Please provide examples of what you'd like to see in this area.	
59	Are there significant advantages in adopting a REZ model, or a central planning model (like the NSW EnergyCo), to coordinate electricity transmission investment in New Zealand? Would a REZ model for local electricity distribution be an effective means of addressing first mover disadvantage with connecting to electricity distribution networks?	Our view of REZ's remains the same as in our submission to Transpower in April 2022 at the link below. We consider that there are other means of addressing this issue, for example reclassifying long connection lines as interconnection assets. https://static.transpower.co.nz/public/uncontrolled_docs/17.%20Contact%20Energy%20Renewable%20Energy%20Zones.pdf?VersionId=JUf18p2MB0jjxj_9k4MGigf1G_NtHf4y
60	Should MBIE regularly publish opportunities for generation investment to enable informed market decision-making?	
61	How should the government balance the aims of sustainability, reliability and affordability as we transition to a renewable electricity system?	We consider that the current settings balance these objectives well. This is reflected in New Zealand's AAA rating on the Energy Trilemma Index.
62	To what extent should wholesale, transmission, distribution or retail electricity pricing be influenced by objectives beyond the (affordability-related) efficiencies achieved by cost reflective pricing, such as sustainability, or equity?	We consider that these wider objectives are already sufficiently met through other mechanisms, such as consenting requirements, and the ETS
63	Are the current objectives for the system's regulators set in law (generally focusing on economic efficiency) appropriate, or should these	We consider the current objectives are appropriate.

#	Consultation question	Contact Energy Response
	also include more focussed objectives of equity and/or affordability?	

Gas Transition Plan – Issues paper

#	Consultation question	Contact Energy Response
1	How can New Zealand transition to a smaller gas market over time?	We consider that the current policy settings are driving a reduction in the use of gas in New Zealand.
2	What is needed to ensure fossil gas availability over the transition period?	In our experience, access to flexible gas is the main difficulty in operating thermal plant, not the ownership or operation of the assets themselves. Accessing flexible gas supply creates a significant risk that is not rewarded in short run marginal costs. To solve for gas supply risk, thermal providers have looked to over the counter arrangements, such as swaptions, which reflect long run marginal costs, including fuel costs. We expect that the market will increasingly value these contracts, but it should be a priority for the government to monitor this market to ensure it is developing as required. If this market does not evolve it would be appropriate for government to consider the barriers, and what interventions may be necessary, while causing the least disruption to the efficient functioning of the market.
3	What factors do you see driving decisions to invest or wind down fossil gas production?	Our strategy is to lead New Zealand's decarbonisation - we do not intend to grow our gas capacity.
4	Does the Government have a role in enabling continued investment in the gas sector to meet energy security needs? - If yes, what do you see this role being?	Removing the target of 100% renewable energy by 2030 would be a significant improvement in the investment environment. As per Q2, government should monitor the development of hedge contracts for flexible electricity supply. Interventions may be necessary if this market does not grow in the way needed.
5	Does the Government have a role in supporting vulnerable residential consumers as network fossil gas use declines? - If yes, what do you see this role being?	Yes, government support for vulnerable consumers may be appropriate. However, this should only occur when residential gas supply becomes uneconomic. When this occurs some households will have a high cost of replacing appliances. It may be appropriate for government to assist with the cost of transitioning these assets.

#	Consultation question	Contact Energy Response
6	What role do you see for gas in the electricity generation market going forward?	As per BCG report, and EA work we see gas having a role out until at least the 2030s.
7	What would need to be in place to allow gas to play this role in the electricity market?	See q2 and q4 above.
8	Do you think gas can play a role in providing security of supply and/or price stability in the electricity market? Why / Why not?	Yes, it has a role to play, particularly over the next decade
9	Do you see alternative technology options offering credible options to replace gas in electricity generation over time? Why / Why not?	Batteries will play a role, as will other storage solutions, such as hydro. We also see an important role for demand flexibility
10	If you believe additional investment in fossil gas infrastructure is needed, how do you think this should be funded?	
11	On a scale of one to five, how important do you think biogas is for reducing emissions from fossil gas? - Why did you give it this rating?	
12	Do you see biogas being used as a substitute for fossil gas? - If so, how?	
13	On a scale of one to five, how important do you think hydrogen is for reducing emissions from fossil gas use? Why do you think this?	
14	Do you see hydrogen being used as a substitute for fossil gas? If so, how and when?	We consider that hydrogen can play a role in certain use cases, such as sustainable aviation fuel.

#	Consultation question	Contact Energy Response
15	What else can be done to accelerate the replacement of fossil gas with low-emissions alternative gases?	We consider the market is responding at the appropriate pace.
16	On a scale of one to five how important is a renewable gas trading to supporting the uptake of renewable gases? - Why have you given it this rating?	
17	What role do you see for the government in supporting such a scheme?	
18	On a scale of one to five how important do you think CCUS is for reducing emissions from fossil gas use? - Why did you give it this rating?	
19	What are the most significant barriers to the use of CCUS in New Zealand?	
20	Do you see any risks in the use of CCUS?	
21	In what ways do you think CCUS can be used to reduce emissions from the use of fossil gas?	
22	What role do you see for gas storage as we transition to a low-emissions economy?	
23	On a scale of one to five, how important do you think increasing gas storage capacity is for supporting the transition? - Why did you give it this rating?	
24	What should the role for government be in the gas storage market?	We consider that a market-led approach will be most optimal.

#	Consultation question	Contact Energy Response
25	Our position is that LNG importation is not a viable option for New Zealand. Do you agree or disagree with this position? - If so, why	
26	What risks do you anticipate if New Zealand gas markets were tethered to the international price of gas?	

Developing a Regulatory Framework for Offshore Renewable Energy – Second Discussion Document

#	Consultation question	Contact Energy Response
1	Following an initial feasibility permit application round, should there be both an open-door policy and the ability for government to run subsequent rounds? If not, why not?	
2	What size of offshore renewable energy projects do you think are appropriate for a New Zealand context?	We consider that a market led approach will result in appropriately sized projects. We do not believe that this needs to be pre-determined. We are aware that offshore wind developments in other countries have become increasing large to improve the project economics. Offshore wind farm sites generally seem to be in the order of 500 MW to 1000GW.
3	Do you think the maximum size of a project should be put forward by developers and set out in guidance material, rather than prescribed in legislation? If not, why not?	We support a developer led approach.
4	Should there be a mechanism for government to be able to compare projects at the commercial stage in certain circumstances? If yes, would the approach outlined in Option 2 be appropriate or would there be other ways to achieve this same effect?	We support option 2 - developer-initiated with an option to compare. When offshore wind becomes viable it is likely that there will be many developers competing over limited resources. It is appropriate for government to prioritise those projects with the greatest value.
5	Are the proposed criteria appropriate and complete? If not, what are we missing?	We support the proposed criteria. It is important that offshore renewables fund the full costs of transmission upgrades. Any cross subsidy would heavily distort the market.

#	Consultation question	Contact Energy Response
6	Should there be mechanisms to ensure developers deliver on the commitments of their application over the life of the project? If yes, what should these mechanisms be?	Yes, we agree with the proposed approach. We consider that the greatest risk of this regime is that speculative permits are granted, and continually extended, harming competition when offshore wind becomes viable.
7	Is 40 years an appropriate maximum commercial permit duration? If not, what would be an appropriate duration?	We agree that 40 years is an appropriate maximum for a commercial permit. Wind turbine design lifetimes are currently about 30 years, but it is reasonable to assume that in some cases they may in practice extend to 40 years. However, if the originally installed turbines continue to operate reliably and the wind farm is still maintained well and operates successfully it may be appropriate to extend a permit rather than requiring a completely new one. We expect permits will be mandatory if a wind farm is repowered and requires new foundations, different turbines, etc.
8	Should a developer that wishes to geographically extend their development be required to lodge new feasibility permit and commercial permit applications? Why or why not?	We agree that any geographic extension of a permit should be treated in the same way as a new permit. Without this requirement a single permit could be used as a 'foot in the door', shutting out competitive proposals.
9	Would the structure of the feasibility and commercial permit process as described enable research and development and demonstration projects to go ahead? If not, why not?	
10	Is there an interdependency between the case for revenue support mechanisms and the decision as to whether to gather revenue from the regime? What is the nature of this interdependency?	We strongly oppose all subsidies for all types of generation. Subsidies would distort investment signals, and result in the wrong mix of assets in the market, making it harder for supply to efficiently meet demand. We find this particularly hard to understand for offshore wind when there is abundant onshore resource, and offshore wind continues to cost 2.5 to 3 times the cost of onshore, with only minimal improvements in capacity factors. Furthermore distributing onshore wind capacity across the country increases diversity, resilience, lower impacts on transmission.
11	Is there a risk in offering support mechanisms for offshore renewables without offering equivalent support to onshore renewables? Are there any	Market signals are already sufficient to drive investment. No subsidies are required.

#	Consultation question	Contact Energy Response
	characteristics of offshore renewables which mean they require support that onshore renewables do not?	
12	Should there be a revenue flow back to government? And, if yes, do you have views on how this should optimally be structured? For comments on potential flows to iwi and hapū please refer to Chapter 7.	It is reasonable for the Crown to recover its costs. We do not think that this should be used as an opportunity to gather revenue, as it would distort the most efficient deployment of electricity capacity.
13	Do you agree with the proposed approach to cost recovery? If not, why not?	
14	Is there anything you would like us to consider as we engage with iwi and hapū on Māori involvement in the permitting regime?	
15	Have we identified the key design opportunities to work collaboratively with iwi and hapū alongside consultation? Is there anything we have missed?	
16	Are there any Māori groups we should engage with (who may not have already engaged)?	
17	For each individual development, should a single consent authority be responsible for environmental consents under the RMA and the EEZ Act? Why or why not?	We support a single consent authority to improve simplicity. One authority covering all offshore developments would ensure that if neighbouring wind farms are proposed they are considered by the same authority, rather than potentially neighbouring regional authorities.
18	Do environmental consenting processes adequately consider environmental effects such that it is not necessary to duplicate an assessment of environmental effects in the offshore renewables permitting regime?	Yes, we consider environmental consents sufficiently consider environmental effects and do not need to be duplicated.

#	Consultation question	Contact Energy Response
19	Should the offshore permitting regime assess the capability of a developer to obtain the necessary environmental consents? If not, why not?	Yes, we consider that this is a key criterion in determining the credibility of a developer and a particular project.
20	What is the optimum sequencing between obtaining feasibility permits, commercial permits and relevant environmental consent(s)?	We support the sequencing proposed by MBIE, starting with feasibility permits, then environmental consents, followed by commercial permits.
21	Are there are any other matters about the environmental consent regimes that you think need to be considered in the context of the offshore renewable energy permitting regime?	
22	How should the factors outlined influence decisions to pursue offshore renewable energy developments in the EEZ or the Territorial Sea? Are there other factors that may drive development in the EEZ versus the Territorial Sea?	
23	Are the trade-offs between a developer-led and a TSO-led approach, set out above, correct? Is there anything missing? What could we learn from international models?	
24	Which party do you think should build offshore connection assets? Can existing processes already provide the flexibility for this to be carried out by the developer?	We are unaware of any impediments of a third party building and owning transmission infrastructure. The 'line of business' restrictions would prohibit the owner of an offshore renewable generator owning the connection assets themselves. If government wants to reconsider if the generator can own connection assets, this should be done across the entire electricity sector, not offshore renewables in isolation.
25	What are the potential benefits and opportunities for joint connection infrastructure? Do you agree	

#	Consultation question	Contact Energy Response
	with the barriers set out and how could these be addressed?	
26	Do you agree with the representation of the timeline challenge for onshore interconnection assets? What opportunities might there be to front load planning work for interconnection upgrades? What role do you see for the developer in this?	This same challenge occurs for all major capacity and load on the network. No special treatment should be given to offshore wind, this should be considered across the entire market.
27	What changes might be needed in order to deliver the types of port infrastructure upgrades needed to support offshore renewables?	Given the limited offshore wind opportunity in NZ, it may be more efficient to use a port in Australia during installation. Any port investigations/upgrades may be better to focus on port requirements for operations rather than installation works.
28	Should developers be required to submit a decommissioning plan, cost estimate and provide a financial security for the cost estimate? If not, why not?	Yes, we consider this is important to determine if an offshore developer, and a particular project is credible.
29	Should the decommissioning plan, cost estimate and financial security be based on the assumption of full removal? If not, why not?	Yes, if the foundation system is not going to be used in any repowering, then its removal should be included in the decommissioning costs.
30	What are your views on the considerations set out in relation to the calculation of the cost estimate and financial security value or suggested approach for financial security vehicle?	
31	What should the developer be required to provide in relation to decommissioning at the feasibility application stage?	
32	What ongoing monitoring approach do you think is appropriate for the decommissioning plan, cost estimate and financial security?	Given the long-time frames involved, and the lack of experience internationally of decommissioning offshore wind, it would be prudent to require updates to decommissioning plans as part of the permitting process. This may occur at say year 20 and year 30

#	Consultation question	Contact Energy Response
33	Are there any other ways in which the regulatory regime could encourage the refurbishment of infrastructure or the recycling of materials?	An assessment of the ability to recycle should be made prior to installation. For example, steel turbine towers can be more easily recycled compared to concrete towers, however this decision needs to be made early.
34	Should offshore renewable energy projects applying for a consent to decommission be required to provide a detailed decommissioning plan related to environmental effects for approval by consent authorities?	
35	How can the design of the regulatory regime encourage compliance so as to reduce instances of non-compliance?	
36	Is the compliance approach and toolbox, described above, appropriate for dealing with non-compliance within the regulatory regime?	
37	Should the decision maker within the regime be the regulator but with an option for the Minister to become the decision maker in a specific set of circumstances? If not, why not?	We support a regulator led model. These are technical matters and best removed from political influence.
38	Should there be an opportunity for public submissions on the commercial permitting decision? What would this capture that the environmental consent decision does not? If not, why not?	Yes, we consider public submissions would be beneficial. This will allow wider industry insight into the viability of a particular project.
39	Should permitting decisions be able to be appealed and if so which ones? Which body should determine such appeals?	We support the ability to appeal decisions.
40	What early information would potential participants of the regime need to know about	

#	Consultation question	Contact Energy Response
	health and safety regulations to inform decisions about whether to enter the market?	
41	What are your views on the approach to safety zones including the trade-offs between the different options presented?	
42	Do you have any views or concerns with the application of these proposals to other offshore renewable energy technologies?	

Implementing a ban on new fossil-fuel baseload electricity generation

<table>
<tr><th>#</th><th>Consultation question</th><th>Contact Energy Response</th></tr>
<tr><td>1</td><td>Do you agree that there is a low likelihood of new fossil-fuel baseload electricity generation plant being built? If not, why not?</td><td>Yes, we don’t see any plausible scenario where new fossil-fuel baseload electricity generation would be built.</td></tr>
<tr><td>2</td><td>Do you agree that its preferable for investors looking to build a new fossil-fuel non-baseload generation plant not to have to apply for an exemption?</td><td>Yes we strongly agree. As covered in our main submission there are already significant barriers to new flexible thermal generation. It would harm the future security and resilience to add more.</td></tr>
<tr><td>3</td><td>What size of new fossil-fuel baseload generation plant should be in scope of the ban?</td><td rowspan="5">We do not support a ban on baseload thermal generation. It is extremely unlikely that new baseload thermal will be built, and no matter how well designed there is a risk that this regime will have unintended consequences on market choices around new flexible thermal stations. This risk is evident in the number of exemptions that need to be considered.</td></tr>
<tr><td>4</td><td>Do you think that there should be an exemption for the replacement of existing baseload fossil-fuelled electricity generation with new fossil-fuel baseload plant of a prescribed efficiency and emissions standard?</td></tr>
<tr><td>5</td><td>Do you think that there should be an exemption for new baseload electricity generation plant that uses blended fuels (i.e., a mix of fossil-fuel and renewable fuel)?</td></tr>
<tr><td>6</td><td>Do you think that there should be an exemption for new fossil-fuelled co-generation plants?</td></tr>
<tr><td>7</td><td>Do you think there should be an exemption for new fossil-fuel baseload electricity generation plant with carbon capture, usage, and storage (CCUS)?</td></tr>
</table>

#	Consultation question	Contact Energy Response
8	Do you agree that an exemption to relax restrictions on non-baseload fossil-fuel plant in a security of supply event is necessary?	
9	Do you think there should be an exemption for the construction of new fossil-fuel baseload generation plants, based on security of supply reasons?	
10	What impact do you think a ban on new fossil-fuel baseload electricity generation will have on fossil gas field development?	
11	What other issues or problems do you see in the implementation of a legislative ban on new fossil-fuel baseload electricity generation?	