Contact Energy Submission

Ensuring an Orderly Thermal Transition: Consultation Paper

25 July 2023

Introduction

1. Thank you for the opportunity to provide our views on the consultation paper: Ensuring an Orderly Thermal Transition.
2. This project is a valuable contribution to the discussion on the energy transition. It shows that there will likely be sufficient thermal generation in the electricity system out to 2032.
3. We broadly agree with the conclusions of the report, noting the finding from Concept Consulting that "the flexibility available from existing peakers plus projected battery growth plus the existing hydro system is very substantial".[1]
4. However, this analysis is incomplete without considering the role of flexible gas supply. This is likely to be very material to the role of thermal through the transition and points to the importance of over the counter (OTC) contracts that sufficiently reward the flexible supply by thermal assets.
5. We also recommend that the scope of this analysis is expanded to cover other forms of flexible supply, such as grid scale batteries and demand side flexibility. These are likely to be the main new sources of flexibility to cover any shortfall, so it is important to ensure that the settings are right to facilitate their entry into the market.
6. For example, we recently announced that we are looking into build a 100MW battery, and are currently doing the internal business case work to reach a final investment decision this financial year.[2] A change to 5-minute pricing would provide a more accurate market signal and encourage more batteries into the market.
7. While a shortfall is not current forecast, it is prudent for the Authority to take any forecast with caution. As noted by Concept, they have not modelled major plant failure, such as the current outage at Huntly Unit 5. This will become more common as the existing assets age. There is also substantial uncertainty regarding future demand, which may be different to that modelled. If in practice a shortfall emerges, batteries and demand side flexibility will be a critical part of the response.
8. In this submission we:

[1] https://www.ea.govt.nz/media/documents/Appendix_C_-_Concept_Consulting.pdf, p20

[2] https://contact.co.nz/-/media/contact/mediacentre/presentations/contact-energy-capital-markets-day-2023-presentation.ashx?la=en

a. Respond to the consultation questions
b. Highlight the risks associated with gas supply through the transition and recommend that the Authority considers this in the next phase of this project
c. Recommend implementing 5-minute pricing to provide a more accurate market signal for grid-scale batteries and some demand side flexibility
d. Respond to concerns raised by the Authority related to market-based mechanisms to reward commercial and industrial demand side flexibility. We consider that a mechanism of this sort will be essential to encourage sufficient flexibility in the market through the transition.

Response to consultation questions

Consultation question	Contact Energy Response
1. Do you agree with the desired outcome as described? If not, what do you think is the desired outcome in respect of thermal generation during the transition?	The desired outcome should be expanded to ensure that there is sufficient flexible supply in the market, rather than just focussing on thermal generation.
2. Are there any other aspects of thermal transition risks that should be considered by the Authority?	We consider that gas supply is the most critical question when considering thermal transition risks, particularly the flexible supply needed for thermal assets to play a back-up role. The hard bureaucratic boundary the Authority has applied for this paper has meant that the analysis is incomplete. We recommend that gas supply challenges are considered in the next stage of this work, potentially alongside the Gas Industry Company. This work should consider how to align gas supply with market needs on a seasonal and daily basis. How do cost structures, and incentives help deliver the best outcome for the market.

Consultation question	Contact Energy Response
3. Do you agree with the above expectation of the likely role of thermal generation throughout the transition? If not, what is your view and reasoning?	We agree that thermal generation will increasingly be confined to providing back-up services, and will play a role in system security in dry years.
4. What (if any) improvements could be made to information to aid decision makers in relation to thermal transition risk?	We consider that the work the Authority is undertaking in relation to winter 23 to be sufficient to fill information gaps for thermal decision makers.
5. Are there any aspects in current spot market arrangements that are likely to undermine incentives to make efficient decisions in relation to back-up resources? If so, what are they?	We consider that the Authority's work programme related to winter 23 will address most challenges to making good decisions on existing back-up resources. In particular we support the work to improve intermittent forecasting, and to clarify the role of ripple control. However, as covered below, we consider that further market adjustments could be made to provide a better signal for other forms of flexibility, like grid scale batteries and demand side flexibility. 5-minute pricing will be critical to reward fast start flexibility, and provide security to the market. We encourage the Authority to add this to its work programme. We also consider that a market-based mechanism is needed to reward demand side flexibility, as covered in our Wholesale Market Review submission, and expanded on below.
6. Do current arrangements provide balanced incentives to conclude forward contracts to manage thermal	Yes, we consider there will be sufficient incentives. Firming supply will become increasingly valuable, and an increasing

Consultation question	Contact Energy Response
risks of transition appropriately? If not, what are the reasons for your view?	number of contracts are being developed to meet this need. These forward contracts are essential to support contracting for flexible gas supply, and ultimately upstream investments. We agree with paras 4.32-4.33 that the threat of political intervention is the greatest risk to appropriate commercial mechanisms developing. Some assurance that this sort of intervention will not occur would provide confidence to the market. We consider that the Authority should prioritise monitoring the development of forward contracts for flexible supply. If they do not develop as expected further options should be considered.
7. Do current arrangements ensure reasonable availability of forward contracts related to back-up services – such as dry year cover? Please explain your reasoning.	Yes, we consider that current arrangements are sufficient to ensure availability of forward back-up contracts. As noted by the Authority there is likely to be sufficient back-up generation physically available across a number of different parties. We see no barriers to contracts continuing to be developed to meet back-up needs.
8. To what extent do current arrangements create potential for misaligned incentives between retailers and consumers in relation forward contracting with adverse impacts on thermal transition risk? Please explain your reasoning.	We are not aware of any evidence that these incentives are mis-aligned.
9. To what extent do current arrangements relating to use of ripple control in periods of tight	We consider that there needs to be increased clarity on when ripple control

Consultation question	Contact Energy Response
supply affect thermal transition risk? Please explain your reasoning.	is being used in the market. This will better inform expected prices for thermal commitment. We broadly support the proposal from the Authority to require distributors to bid in ripple control into the wholesale market. Ultimately, we would like to see ripple control subject to commercial incentives, and offered into the market by retailers directly.
10. Do you agree with the Authority's view above that lumpiness does not (at present) threaten to disrupt an orderly thermal transition? If so, or if not, please explain your reasoning.	In 2021 Contact Energy published the paper 'Crafting a path for New Zealand's 100% renewable electricity market', in which we proposed a Thermalco to help manage thermal assets and set a coordinated retirement plan. We consider that this is the best option to address any lumpiness in the thermal transition.
11. To what extent are there any selective support mechanisms paid outside the wholesale market that could pose a challenge to achieving an efficient thermal transition? Please explain your reasoning.	We are not aware of any selective support mechanisms paid outside the wholesale market. We broadly agree with the Authority that if such mechanisms are developed they may harm investment incentives and the ability to retain sufficient firming capacity in the market. For that reason we were tentatively supportive of the Winter Peak Product proposed by the Energy Chairs as a response to immediate risks, but agreed with the Authority it would pose risks if it were a long term solution.
12. To what extent is thermal generation providing a service that is	We consider that the capacity benefits and provision of firm and secured

Consultation question	**Contact Energy Response**
needed but not explicitly priced and rewarded? Please explain your reasoning.	upstream energy supply of thermal sites are already sufficiently rewarded by OTC hedges, such as the swaption arrangement with Meridian where a price, which is reflective of the LRMC of generation plus fuel, is baked into the agreement. Where that service is via the Spot Market there is a continued challenge to ensure that all necessary costs, including plant investment costs, fuel storage costs (like Ahuroa Gas Storage) and flexibility premia to fuel suppliers, is recovered. This may, in certain hydrological scenarios, require increased offer prices away from the plant SRMC, to recover all thermal costs, particularly in sequences where must run fuel is run at a prolonged and unhedged loss.
13. To what extent will thermal retirement/investment decisions be driven by non-financial factors? Please explain your reasoning.	For certain companies non-financial factors will be a significant factor in deciding to exit the thermal generation market. As a publicly listed company we have found investors are increasingly attracted to businesses with strong environmental social and governance (ESG) credentials. We put considerable effort into demonstrating our ESG performance to the market, including our recent public commitment to be net zero from our generation operations by 2035. However, given the critical role that back-up thermal has in a well-functioning low-carbon electricity system, we consider that continuing to operate our existing thermal assets

Consultation question	Contact Energy Response
	through the transition supports both our ESG goals and New Zealand's commitment to net zero by 2050.
14. What (if any) other factors could undermine an efficient thermal transition? Please explain your reasoning.	We are not aware of any other factors
15. Do you have any views on the options discussed above, and how useful they might be if thermal transition risks increase in future?	We agree with the set of options considered by the Authority. However, we consider that the scope of analysis should be widened to consider gas supply flexibility and other forms of flexible supply like grid scale batteries and demand response.
16. What other options (if any) could be explored to mitigate thermal transition risks, should these risks increase in future? Please explain your reasoning.	More attention should be placed on ensuring the appropriate market conditions for other forms of flexible supply, such as batteries and demand response. As we show below, moving to 5-minute pricing would provide a better market signal, encouraging more grid scale batteries into the market. Similarly, a market-based mechanism for demand response will optimise the amount of flexibility in the market.

The Authority must also consider gas supply

9. This analysis is incomplete without consideration of gas supply. While we note that the Authority considers gas supply outside of its remit, bureaucratic walls should not stand in the way of a full consideration of the risks to thermal generation.
10. 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 (eg gas exploration ban)

b. As baseload thermal exits the market, a larger portion of gas demanded by the 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, as highlighted in our submission on the Wholesale Market Review.

11. Accessing flexible gas supply creates a significant risk that is not rewarded in short run marginal costs. The 'take or pay' contracts common in the gas markets are having an increasing impact as the proportion of flexible gas increases. To ensure that thermal can play a back-up role, we are conservative in our supply contracts, creating a significant risk that we will buy more gas than needed.

12. This risk plays out most in wet years, where we will have contracted for more gas than is needed. In these years we will often be forced to run thermal assets in a loss-making position. This means there is an increasing gap between long run marginal cost and short run marginal cost.

13. We are able to partially solve this risk via gas storage, such as the Ahuroa Gas Storage (AGS) facility. However, these storage facilities themselves have considerable running costs, which are not reflected in short run marginal costs.

14. 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. As above, we expect that the market will increasingly value these contracts, but it should be a priority for the Authority to monitor this market to ensure it is developing as required.

15. Greater consolidation of thermal assets would also mitigate this risk, and was a major motivating factor behind our Thermalco proposal.[3] We continue to see value in this proposal being implemented, but consider it would be most effective if it were industry-led.

16. In the next stage of the thermal transition project we recommend that the Authority:

[3] https://contact.co.nz/aboutus/media-centre/2021/11/15/thermal-co-enabling-aotearoas-transition-to-renewable

a. Considers the impact of gas supply on thermal transition risks, including recognising the need for high thermal offers to recover long run marginal costs, and the role of thermal stockpiles.
b. Commits to monitoring the development of forward contracts, such as swaptions, and consider options to encourage the development of this part of the market.

5-minute pricing will provide a stronger market signal for fast start flexibility

17. The 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.
18. 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.
19. 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.
20. This issue was considered in depth by AEMC, and 5-minute pricing was implemented in the Australian National Electricity Market on 1 October 2021. In their final decision the 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.[4]

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

22. We appreciate that this would be a material change, and may take several years to implement. But given its importance in incentivising flexibile capacity we encourage the Authority to build this into its work programme.

Commercial and industrial demand side flexibility

23. Concept Consulting's modelling relies on up to 7.5% of total demand being available for demand side flexibility (DSF). In the modelling that Concept undertook as part of the 'Future is Electric' report, they estimated about 300-400 MWh from commercial and industrial DSF by 2040. This is roughly equivalent to the output of Contact Energy's 210 MW gas peaking plants. We consider this to be unrealistic under current settings.

24. In our submission to the Wholesale Market Review we highlighted some key barriers to commercial and industrial DSF developing at scale. In summary there are three interrelated problems, also shown in figure 1:

    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. As we discuss below, 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

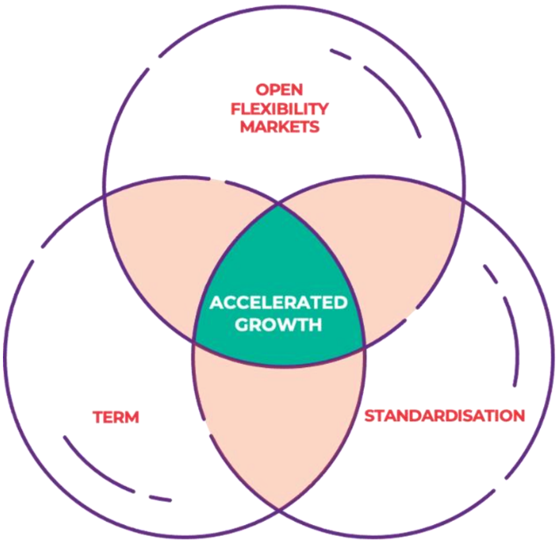
[4] https://www.aemc.gov.au/sites/default/files/content/97d09813-a07c-49c3-9c55-288baf8936af/ERC0201-Five-Minute-Settlement-Final-Determination.PDF, pii

cash-flow. A longer term allows the flex trader to take the volatility risk, and be more certain of a sufficient return.

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.

25. As per figure 1 below all three of these features needs to be present to have the optimal level of demand side flexibility.

Figure 1: Key features required for commercial and industrial demand side flexibility to emerge at scale



26. In the final Wholesale Market Review paper the Authority indicated it was open to considering options to accelerate DSF. However, two concerns were raised:

a. it may not be appropriate to develop regulatory mechanisms to address what are seemingly more commercial matters; and

b. the risks associated with establishing a baseline, including the administrative complexity, payments for reduced demand that would have happened anyway, and the risk of gaming the system.

27. We address these concerns below.

Leaving commercial and industrial DSF to bilateral contracts will lead to less flexibility available in the market

28. In general, we are supportive of avoiding regulation where commercial arrangements are available. However, as noted by the AEMC “there are commercial barriers to developing the required partnerships between retailers and demand response providers”.[2]

29. In most DSF arrangements we expect there to be three parties:

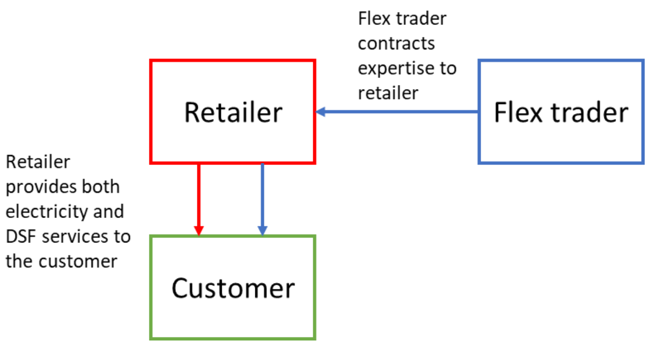
    a. The customer providing the capacity

    b. The customer’s retail electricity provider

    c. The flexibility trader. We expect that in most cases this will be a separate party to the retailer because of the term issue discussed above, and because of the different capabilities required by a flexibility trader and a retailer. However, in some cases the retailer and the flexibility trader will be the same organisation.

30. We can broadly see three different ways that these parties may organise themselves. The first two are available under current settings, but will result in a sub-optimal amount of DSF. The third option is to introduce a market-based mechanism to directly reward DSF, such as the Wholesale Demand Response Mechanism in Australia.

Flex trader as an expert consultant to the retailer

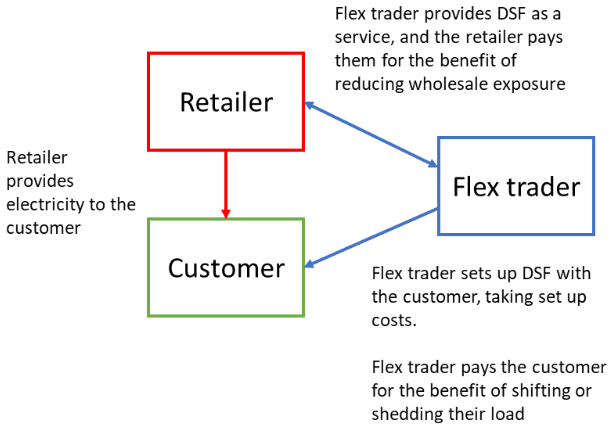


31. A flex trader could operate as an expert consultant to the retailer, helping them with the know-how and equipment needed to set up DSF.

32. This scenario is equivalent to the retailer offering flexibility services themselves. All the set-up costs fall on the retailer. This means the retailer will face the term issue described above. The retailer would be unable to recover the set-up costs of DSF within a standard retail contract term.

Flex trader providing flexibility as a service to the retailer

33. Another option is for the flex trader to sell a complete DSF capability as a service to the retailer. The flex trader works with the customer to set up flexibility capacity, and incurs the set-up costs. The flex trader then contracts with the retailer, effectively selling them a reduced wholesale cost exposure. The flex trader then uses some of the income they get from the retailer to pay the customer.



34. Under this arrangement the retailer holds all the power, and in some cases may simply choose to not work with the flex trader. As noted by the AEMC:

> 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. [5]

35. If the retailer chooses to work with the flexibility trader then the benefits of flexibility (lower exposure to wholesale peak costs) must be split three ways between the retailer, the flex trader and the customer. The proportion of this split that goes to retailers is effectively a dead weight cost, it reduces the size of the return to incentivise customers to supply DSF, and the return to justify the costs of setting up a DSF arrangement for the flex trader.

36. In theory, in a perfectly competitive market with high elasticity of demand then the share of the DSF benefit retained by retailers would be zero. This is because the lower wholesale cost granted by DSF would reduce input costs, which would ultimately result in a lower price to the consumer. If retailer A chose to work with the flex trader, but retailer B didn't then retailer A would have a lower cost offering and win the business. Because of this both retailers are incentivised to work with the flex trader, and because both will have lower input costs, they will compete away this benefit, leaving the customer better off. So even if it appears that the

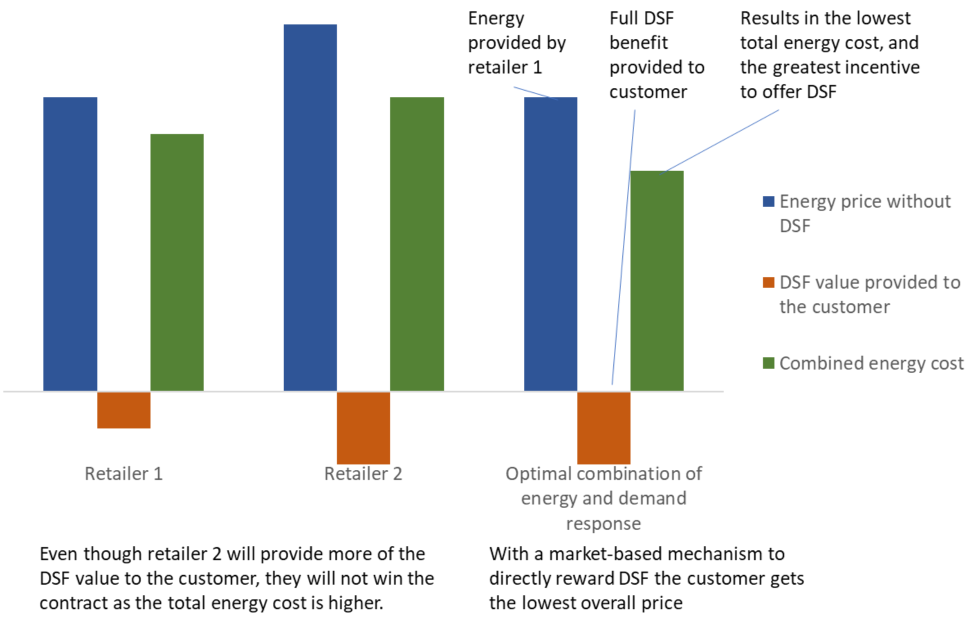
[5] https://www.aemc.gov.au/sites/default/files/2018-07/Final%20report_0.pdf, p53

retailer is retaining some of the value of DSF, competition will mean they actually pass the benefit on to consumers.

37. However, as we showed in our submission to the Market Development Advisory Group (MDAG), retailers in the commercial and industrial space do not have homogenous input costs. The value of DSF can be swamped by other factors when determining retail tariffs, such as the location of generation assets, different hedging strategies, portfolio risk mitigation strategies, etc. For example, Meridian has an incentive to grow its South Island customer base to offset the geographic imbalance of its generation portfolio.

38. Because of the different cost bases there is significant scope for retailers to retain much of the value of DSF for themselves. A stylistic representation of this is shown in figure 2 below.

Figure [2]: Stylistic example of why retailers have significant scope to retain much of the value of DSF

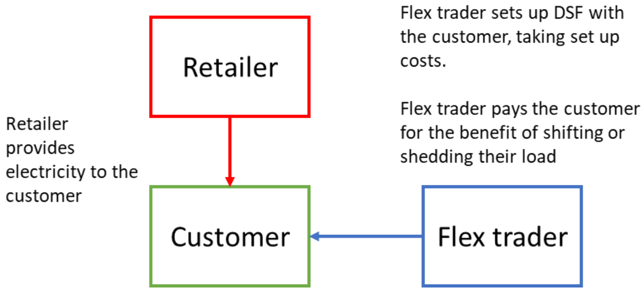


39. Because retailers can retain a significant portion of the value of DSF, it means there is less available to the customer who is actually providing the capacity. That means some marginal DSF will not come to the market because there is an insufficient return.

40. When the customer switches retailer this whole process starts again. The next retailer may be un-interested in DSF, or may want a large portion of the value, making it hard for the flex trader to recover its sunk costs. Given this potential

outcome, the initial investment decision is very risky, stopping DSF before it starts.

A market-based mechanism allows the flex trader to contract directly with the customer



41. A third option would be for retail electricity services and flexibility services to operate independently of each other. In this case the customer will get the maximum value for providing DSF, maximising the amount of capacity in the market.

42. One way of achieving this is the Wholesale Demand Response Mechanism developed in Australia. This is a market-based mechanism where flexibility traders are paid for reduced load directly from the wholesale market.

43. A market-based DSF mechanism is also better aligned to the needs of customers. Beyond the handful of largest energy users, most commercial and industrial customers have a preference for energy contracts that are standardised, remove complexity and risk, and allow for accurate cashflow forecasts. A market-based mechanism allows for energy contracts to be kept simple and standardised, while still separately capturing the value of DSF. The longer term certainty of a market-based mechanism also allows for regular payment to the customer for DSF capacity, with the flex trader taking the market volatility risk.

Are there risks in setting baselines?

44. Setting baselines is a necessary part of any DSF arrangement, whether it is enabled through a market-based mechanism or agreed in commercial contracts. Without this counterfactual it is not possible to measure the size of the response. The only way to avoid baselines is to avoid DSF.

45. A market-based mechanism like Australia's Wholesale Demand Response Mechanism can reduce the risks of baselines. For example, the AEMC did this by:

    a. Limiting the mechanism to commercial and industrial customers who typically have a more stable consumption profile, making it easier to set baselines; and

    b. Setting specific baseline methodologies. The AEMO set four baselines that flexibility traders can choose between. The flexibility trader must then demonstrate that the baseline methodology is accurate and without bias for the particular load. The AEMO then undertakes compliance assessments on the baselines.

46. Further, standardisation of baseline methodologies through a market-based mechanism will reduce information asymmetry between the various parties. This will allow more accurate valuation of flexibility services so that they can be agreed at scale with confidence.

47. In the recent annual report on the Wholesale Demand Response Mechanism AEMO found that “the four available baselines methodologies and the eligibility assessment, compliance testing and non-conformance processes are all functioning as expected”.[6]

48. This demonstrates that the risks of baseline error can be managed, and should not be a major barrier to developing a similar market-based mechanism in New Zealand.

[6] https://aemo.com.au/-/media/files/initiatives/wdr/wdrm-annual-report_2023_final.pdf?la=en