Rewarding industrial demand flexibility

Issues and options paper

28 May 2025

ELECTRICITY AUTHORITY
TE MANA HIKO

Executive summary

One of the ways to help manage our electricity supply for the long-term benefit of consumers is to lower demand for power at peak times, when it is scarce and expensive. For example, industrial plants (industrials) that use a lot of electricity can choose to use less electricity at peak times in a controllable way. We refer to this as 'industrial demand flexibility'.

The Energy Competition Task Force (Task Force) has considered measures that would enable industrials to be appropriately rewarded for the benefit their demand flexibility offers the electricity market. The Electricity Authority Te Mana Hiko (the Authority) is now seeking feedback on a proposed vision and five-year roadmap for industrial demand flexibility.

As the level of intermittent electricity generation (wind and solar) in Aotearoa New Zealand increases and thermal generation reduces, the need for flexibility (including demand-side flexibility) will become increasingly important. Efficient provision of flexibility services from a range of sources will help ensure a secure and cost-effective electricity supply, for the long-term benefit of consumers. The Authority has a number of initiatives underway that seek to achieve this outcome.

Industrial demand flexibility is one way of doing this – actively adjusting industrial electricity use to help maintain balance in the power system can reduce the need for more expensive electricity generation to manage peaks (particularly during winter when demand is highest).

Many in the sector are of the view that industrial demand flexibility is underutilised – and that New Zealand is missing out on the benefit of this flexibility, either due to barriers in the system or missing (efficient) incentives. We are seeking to further explore and respond to this view via our proposed vision and five-year roadmap for industrial demand flexibility.

We have focused on industrial demand flexibility given the characteristics of these consumers, including their existing engagement with market mechanisms and larger load profiles. We recognise that there is likely to be significant potential demand flexibility from other consumers, including aggregations of residential and smaller commercial consumers. We welcome any feedback on this point, including on the applicability of the vision and approach proposed in this initiative to other forms of flexibility.

The work under this initiative explores potential ways for industrials to be adequately rewarded for helping balance the electricity system during peak periods, ie, providing intra-day flexibility, particularly during times of higher demand and tight supply such as in winter. We are not focusing on seasonal demand response arrangements. These arrangements require more substantial and prolonged reductions in demand and can therefore come at a high cost to productive economic activity, employment and exports.

While maximising the potential benefit from existing industrial consumers is important, we think it is equally important to put foundations in place to enable additional efficient demand flexibility from a range of sources (including industrials) as demand increases and industries and technology evolves. This will give greater certainty to businesses looking to upgrade or connect to the network and increase the pool of potential future demand flexibility providers.

This work focuses on enabling 'explicit' demand flexibility. This is where consumers adjust their demand in response to an instruction from the system operator, or under a contract (and are rewarded for this). By contrast, 'implicit' demand response relies on consumers managing demand in response to electricity price signals, and has already received substantial attention from the Authority, such as through real-time pricing driven initiatives.

The current potential for industrial demand flexibility is lower than expected, but still highly valuable

To properly frame this work, the Authority has considered the technical potential for industrial demand flexibility and consumers' willingness to make their demand flexibility available.

The Authority commissioned Sense Partners to undertake a high-level desktop study of currently available demand response (Appendix C). This found that there is around 170 megawatts (MW) of 'high confidence' industrial demand response currently available to provide intra-day flexibility services – around the same scale as a medium-sized power plant. This suggests that there is currently a modest, yet meaningful, amount of industrial demand flexibility that could be made available if there is sufficient incentive to do so. Further, we expect this potential to grow as new industrials and industries (such as data centres) come online and the maturity of demand side technologies increases.

Given current industrial demand flexibility potential is relatively modest, its highest value is likely to be in periods when electricity demand is very high and supply from other sources may be limited and very high cost. Reducing demand during these relatively short periods could deliver substantial benefits, through lower spot market prices and enhanced reliability (avoiding involuntary load shedding). In these circumstances, industrial demand flexibility should also only have a minor impact on the industrial's output and the wider economy, so the opportunity cost is low compared to longer-term or 'seasonal' demand response (such as bilateral contracts between gentailers and industrials). However, we are open to views on the most efficient and effective uses of industrial demand flexibility for the electricity system and consumers.

Our proposed vision for industrial demand flexibility

We propose the following vision for industrial demand flexibility in Aotearoa New Zealand:

To enable efficient industrial demand flexibility so it achieves long-term benefit for consumers by promoting a competitive, reliable, and efficient electricity industry.

This vision is aligned with the Authority's main statutory objective and the 2024 Government Policy Statement on Electricity. It recognises that demand flexibility can be considered efficient when it creates net benefits to consumers through lower costs over the long-term. This could involve payments to industrial demand flexibility providers, additional to avoided energy costs – if there is a clear benefit for consumers. We recognise that this represents a shift in the Authority's thinking about how best to reward demand flexibility.

Our focus on providing net benefits to consumers keeps us agnostic to how industrial demand flexibility is provided, such as via a central market mechanism or commercially negotiated bilateral contract.

Our vision places industrial demand flexibility within a wider efficient, flexible system. We think that market settings should promote industrial demand flexibility where that is the most efficient flexibility option, rather than aiming to 'achieve' an arbitrary MW target of demand response from industrials.

Taking action to enable more industrial demand flexibility

Reflecting our proposed vision, we have identified 11 potential actions to enable and reward industrial demand flexibility over the next five years. These actions, which make up our proposed roadmap, have been informed by our proposed guiding principles (set out in section 7) and reflect:

- the scale of potential short-term flexibility services currently available from industrials
- identified barriers to the provision of more industrial demand flexibility
- the expectation that potential for demand flexibility will grow into the future, including as a result of the continued maturing of demand side solutions and in response to the incentives proposed as part of this and other initiatives for flexibility services.

Our draft proposed roadmap is attached in full at Appendix A. The roadmap:

- focuses on improving incentives for explicit industrial demand flexibility
- recognises that the Authority does not have full visibility of all current bilaterally contracted industrial demand response. More information about these agreements is needed to confirm whether these existing mechanisms for demand flexibility are effective, or whether there are barriers or missing incentives to be addressed
- seeks to progress beyond pilots and trials to embed use of industrial demand flexibility
- is seeking to lay the foundations for greater use of efficient industrial demand flexibility as potential grows over time.

We propose two actions to be advanced immediately

We propose to take two immediate actions. In our preliminary view, these are relatively quick and low-cost to implement, and would promote efficient industrial demand flexibility:

Action 1. An Emergency Reserve Scheme **(ERS)**

Transpower's supply outlook indicates that peak capacity risks, especially during cold snaps, will persist until there is sufficient investment in flexible resources such as batteries, demand response and peaking generation. Our preliminary findings indicate industrial demand flexibility can deliver value in these circumstances, potentially offering an efficient solution when compared to the cost of investing in additional supply for brief and infrequent use.

Enabling industrial demand flexibility to provide emergency reserves may unlock greater potential for the provision of short-term flexibility services, if the scheme is able to cover some or all of the upfront costs of enabling this flexibility. The Authority's plan is to publish a separate consultation document on an emergency reserve scheme in July 2025.

Action 2. A standardised demand flexibility hedging product

The Market Development Advisory Group, the Standardised Flexibility Product Co-design Group and the Authority's risk management review all identified a need for more hedging options to support the transition to more variable renewable generation. A standardised flexibility product for industrial demand would promote innovation in the development of demand flexibility services and improve access to flexibility for all potential buyers, especially smaller retailers, supporting prudent and efficient risk management. We propose to set up a co-design group to explore and design such a product, similar to how the 'super peak' standardised flexibility product was developed as part of an earlier Task Force initiative.

If we took forward these two options, we would need to consider how they should work together to ensure their benefits are maximised (for example, an ERS could reduce participation in bilateral arrangements). We would particularly appreciate your feedback on this and other potential issues.

Subject to further development and consultation, we plan to have these two initiatives in place ahead of winter 2026.

We propose a further nine actions over the next five years

We propose to take a range of further actions over the period 2025 to 2029, to unlock efficient industrial demand flexibility and lay the foundations for the future provision of demand flexibility services. We are open to feedback on these and welcome any thoughts on their phasing or relative priority.

We note that these actions are likely to have relevance for demand flexibility provided by industrials and other consumers, and we recognise the potential for greater benefits to be realised by enabling efficient demand flexibility from all consumer types. We welcome feedback on the applicability of our proposed actions to other demand flexibility providers, such as aggregators of residential and smaller commercial consumers.

Our draft roadmap is designed to be relatively modular and respond to market developments. If further action is required faster, or different approaches are shown to better achieve our proposed vision, then the roadmap may be refined in response to this.

We want your feedback

We have taken the opportunity as part of this Task Force initiative to consider industrial demand flexibility with fresh eyes. We also recognise that many stakeholders have a deep interest in enabling demand flexibility and will have insight and experience that will be valuable as we refine our thinking and develop a final roadmap.

We are seeking your feedback to inform our next steps with this initiative, including any further insight you can provide on potential industrial demand flexibility, how it can be incentivised to participate in Aotearoa New Zealand’s electricity market, and any other issues you think are relevant for us to consider.

Contents

1. How you can inform our thinking

What this consultation is about

1.1. The Electricity Authority Te Mana Hiko (Authority) is seeking feedback on a proposed vision and five-year roadmap to ensure that we get the right settings in place to enable greater, efficient, participation in the market from industrial demand flexibility,[1] particularly for providing short-term flexibility (such as supporting the electricity system during periods of high demand and tight supply).

1.2. The need for flexibility from a range of sources, including demand flexibility, will increase as more intermittent generation is commissioned. Consumers such as industrials and larger commercial businesses can make a meaningful contribution to the electricity system in these situations. By adjusting their demand, they can help lower spot prices and support system security, particularly during peak periods when electricity supply is tight.

1.3. The opportunity already exists for larger consumers to provide demand flexibility in the electricity market, and this will grow as new industrials and industries connect, manufacturing plants are electrified, and demand management solutions mature over time. Currently, however, the Authority is not satisfied that incentives for demand flexibility are strong enough to make the most of this opportunity. While some industrial demand flexibility has been arranged through bilateral contracts, no industrials are currently participating in existing demand response mechanisms in the market. It is likely that potential benefits to consumers are not being realised.

1.4. This consultation paper sets out:

(a) estimates of the potential industrial demand flexibility that could be available for short-term flexibility services, and the incentives that may be required for consumers to make this available

(b) a proposed vision for industrial demand flexibility, both now and in the future as the potential for demand flexibility grows

(c) a draft roadmap of actions to enable this vision over the next five years, along with principles to guide the scope and design of options. This includes two immediate measures that the Authority could put in place before winter 2026:

i. An Emergency Reserve Scheme (ERS) in which industrials could participate. Given the complexity and technical aspects of such a mechanism, the Authority plans to release a dedicated consultation paper on this scheme in July 2025.

ii. A standardised demand flexibility product, as recommended by the Standardised Flexibility Product Co-design Group (Co-design Group). The Authority proposes that this would be developed in a similar manner to the standardised 'super-peak' hedge contract introduced in January 2025.

[1] We are using the term industrials as a shorthand. For the purposes of this initiative, 'industrials' include large direct-connect consumers along with medium-sized commercial and industrial consumers who are not directly connected to the transmission system, but have large, disaggregated loads (eg, supermarkets).

1.5. Discussions about how best to activate demand flexibility in Aotearoa New Zealand have been ongoing since the market was established in the 1990s. We aim to ensure that this paper sets a clear direction for further work. We are seeking your feedback on how we have identified the opportunity, our proposed vision, and supporting draft roadmap.

1.6. We want to get the incentives for industrial demand flexibility right – international experience has shown that mechanisms need to be carefully considered in order not to distort the market. Your feedback will help us to do this.

1.7. We also recognise that there is likely to be significant potential demand flexibility from other participants (eg, aggregators of residential and smaller commercial consumers). We welcome any feedback on this point, including on the applicability of the proposed vision and approach to other forms of flexibility.

1.8. Given the technical nature of the subject matter covered in this paper, we have provided a glossary of key terms at Appendix E.

How to provide feedback

1.9. We prefer to receive feedback in electronic format (Microsoft Word) in the format shown in Appendix D. Please email your feedback to taskforce@ea.govt.nz with 'Rewarding Industrial Demand Flexibility' in the subject line.

1.10. If you cannot send your submission electronically, please contact the Authority on taskforce@ea.govt.nz or 04 460 8860 to discuss alternative arrangements.

1.11. Please note that the Authority intends to publish all submissions it receives. If you consider that the Authority should not publish any part of your submission, please:

(a) indicate which part should not be published and explain why we should not publish that part

(b) provide a version of your submission the Authority can publish (if we agree not to publish your full submission).

1.12. If you indicate part of your submission should not be published, the Authority will discuss this with you before deciding whether to not publish that part of your submission.

1.13. However, please note that all submissions received by the Authority, including any parts that the Authority does not publish, can be requested under the Official Information Act 1982. This means the Authority could be required to release material not published unless good reason existed under the Official Information Act to withhold it. The Authority would normally consult with you before releasing any material that you indicated should not be published.

When to make a submission

1.14. Please deliver your submission by 5pm, 26 June 2025.

1.15. Authority staff will acknowledge receipt of all submissions electronically. Please contact the Authority at taskforce@ea.govt.nz or 04 460 8860 if you do not receive electronic acknowledgement of your submission within two business days.

2. Context

This paper supports our work through the Task Force to provide more options for consumers, and supports our wider work on flexibility

2.1. The Authority and Commerce Commission Te Komihana Tauhokohoko (Commerce Commission) jointly established the Energy Competition Task Force (Task Force) in August 2024. This was in response to sustained high wholesale electricity prices, driven primarily by fuel shortages. The Task Force is focused on short- to medium-term actions to improve the performance of the electricity market. Its work programme aims to achieve two overarching outcomes:

(a) enabling new generators and independent retailers to enter and better compete in the market (Package One)

(b) providing more options for consumers of electricity (Package Two).

2.2. These outcomes will encourage efficient investment in new electricity generation, boost competition, enable homes, businesses and industrials to better manage their own electricity use and costs, and put downward pressure on prices.

2.3. Efficient provision of flexibility services from a range of sources will help ensure a secure and cost-effective electricity supply for New Zealand, and the Authority's work programme includes a number of initiatives that seek to achieve this outcome, including facilitating the distributor involvement in flexibility services market and on requiring more retailers to offer time-of-use pricing.

2.4. The Authority also identified the acceleration of demand response participation as a priority in our Peak Capacity Decision Paper.[2] We are continuing our work with participants to facilitate demand response from small consumers and aggregators. This includes trials and regulatory sandboxes to discover and remove technical and regulatory barriers to entry. Most of the recently announced Power Innovation Pathway initiatives focus on improving the use of demand response and flexibility services.

2.5. This Task Force initiative is considering measures that would enable industrials to be appropriately rewarded for the benefit their short-term (eg, intra-day) demand flexibility can bring to the system and consumers. In our view, these benefits are not being realised under current settings.

2.6. Focusing on short-term flexibility minimises the impacts on industrial economic activity compared to long-term responses (such as seasonal demand response arrangements). This is because it requires less substantial and briefer shifts in demand and should therefore come at a much lower cost to productive economic activity (see paragraph 3 for further discussion). Both industrials and the wider electricity market could benefit from measures to unlock this type of flexibility.

Background

2.7. Demand flexibility, also referred to as demand response, provides flexibility by adjusting electricity demand (consumption) in response to market and network

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[2] Electricity Authority, *Driving efficient solutions to promote consumer interests through Winter 2023 – decision paper*, 2023.

conditions. Generally, this involves reducing demand in response to high wholesale prices or congestion in the electricity network.[3]

2.8. Demand flexibility may offer potential benefits for those who can provide it, and to the broader electricity market. These benefits include:

(a) reducing electricity costs for the demand flexibility provider by avoiding higher prices or shifting demand to lower priced periods

(b) competing with supply (ie, generation and storage) to ensure pricing, and ultimately investment, in the wholesale electricity market is efficient. This potentially reduces energy costs for all consumers by reducing the incidence or extent of high prices[4]

(c) avoiding or deferring the need for upgrades to the transmission or distribution networks by helping alleviate constraints or manage other risks

(d) supporting overall system reliability by reducing the risk of involuntary load reductions during periods of high demand or low supply.

2.9. Historically, New Zealand's electricity market, like those around the world, has focused primarily on enabling the supply of electricity to largely passive demand (consumers). The focus has been on ensuring the supply side was adequate and cost-effective in meeting the needs of the demand side. Much less focus was on the ability or willingness of the demand side to actively manage its consumption.

2.10. Hopes for an increase in demand-side participation in the energy market were nonetheless present when the New Zealand electricity market was established and have persisted since.[5] One demand response tool that has long been used is ripple control, which electricity distribution businesses have employed to turn off consumers' hot water systems at times of peak demand since the 1950s. Since the advent of the wholesale electricity market and the split of networks from retail, the use of ripple control to respond to wholesale market price signals has been diluted, but there has been increasing focus on this as a source of flexibility in recent years.

2.11. Existing wholesale market mechanisms for demand response include the instantaneous reserves ancillary service procured by the system operator. Here demand response can be offered along with supply-side resources to manage the risk of an unexpected loss of supply in the system.

2.12. Additionally, the Dispatchable Demand (DD) mechanism (established in 2014) allows larger consumers to compete directly with generators to set the spot price of electricity and benefit from greater control over their energy costs. This is the main wholesale market mechanism for industrial consumers. In the years since, DD

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3 In theory, customers can also provide flexibility by increasing their consumption, which could provide benefits in some circumstances such as during periods of very high variable renewable electricity generation to ensure adequate demand to retain non-inverter-based generation online for system security purposes. However, this is currently a less likely driver of flexibility needs.

4 An example of efficient demand flexibility could be a situation during a peak demand period where the industrial consumer's response acts to lower demand, as an alternative to an expensive marginal generator setting the price. This means the equilibrium price in the wholesale market settles at a lower level. In this example, it's important to note that this flexibility is not 'free' as there are opportunity costs for the provider, along with other indirect costs, that need to be considered.

5 For example: Dr Stephen Batstone, *MDAG – Price Discovery with a 100% Renewables Wholesale Market: Prospects for the uptake of demand-side flexibility in the New Zealand wholesale electricity market under 100% renewables*, 2022, p2.

(along with the Dispatch Notification mechanism for smaller consumer loads) has been amended on several occasions to seek to enable greater participation by industrials. Currently, no industrials are participating in the scheme. These mechanisms rely on the avoidance of high prices to incentivise participation, rather than the industrials being paid to reduce consumption.

2.13. Outside of the wholesale electricity market, demand response is also enabled under a range of bilateral contracts between consumers, retailers and network businesses.[6]

2.14. Notwithstanding the existing opportunities for demand response, there remains a perception that, in general, demand flexibility is currently underutilised in the New Zealand electricity market. The Market Development Advisory Group's (MDAG) report set out range of reasons why demand-side engagement was potentially underutilised – one of the key drivers being that the potential 'payoff' from changing electricity consumption in response to spot pricing has been low.[7]

2.15. To date, the Authority has not favoured schemes that go beyond offering price avoidance to the demand flexibility provider. This position was informed particularly by the concern that, from an electricity market perspective, paying consumers to not consume would result in their 'over-compensation.'[8] This would result in a distortion that could increase demand response above 'efficient' levels, which would in turn hinder investment in other forms of peak demand management (ie, peakers and batteries).

Demand flexibility incentives have been considered in several recent reviews

2.16. Incentives for demand response in New Zealand have been considered in three recent reports:

(a) MDAG's *Price discovery in a renewables-based electricity system report,* published in 2023[9]

(b) the Authority's *Driving efficient solutions to promote consumer interests through Winter 2023* (Winter 2023) decision paper, published in 2023[10]

(c) the Authority's *Potential solutions for peak electricity capacity issues* (Peak Capacity) decision paper, published in 2024.[11]

MDAG recommended a market-led approach to unlock efficient demand flexibility

2.17. MDAG recommended a market-led approach to demand-side flexibility, arguing that competition would unlock the most efficient forms of demand response. However, it did make a contingent recommendation to develop a 'last resort' demand side flexibility scheme (recommendation 30). This was conceptualised as being similar to Australia's Reliability Emergency Reserve Trader (RERT) scheme.

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6 These include the 20-year bilateral long-term contracts between the New Zealand Aluminium Smelter (NZAS), Meridian, Contact and Mercury, as well as smaller scale agreements between EDBs and load centres.

7 MDAG, Price Discovery in a renewables-based electricity system, 2023, p. 116-117.

8 We note that this position does not recognise the opportunity and production costs to industrial consumers from providing this demand response.

9 MDAG, *Price discovery in a renewables-based electricity system*, 2023.

10 Electricity Authority, *Driving efficient solutions to promote consumer interests through Winter 2023 – decision paper*, 2023.

11 Electricity Authority, *Potential Solutions for Peak Electricity Capacity Issues – decision paper*, 2024.

2.18. This type of mechanism can include industrial demand flexibility. This recommendation was contingent on the Authority not being satisfied the market was procuring enough demand flexibility to adequately manage security of supply.

The Authority considered a range of options as part of our wider work on peak electricity demand

2.19. The Winter 2023 decision paper investigated whether separate payments outside of the spot market could be used to encourage providers to make more resource available. For example, the system operator could contract with providers to make additional resource available (eg, during low residual conditions when there are less than 200MW of headroom in the supply stack).

2.20. Building on this work, the Peak Capacity paper also investigated interim solutions in the form of contracts for out-of-market resource. These include contracts for emergency demand response, and residual payments for participants to commit their resource to market.

2.21. Ultimately, the Authority decided not to progress any of these options, because we considered that they would:

(a) not guarantee that only resources that were additional to the business-as-usual scenario were rewarded (additionality)

(b) be unlikely to be effective at providing additional resilience in the short term to manage peak capacity issues

(c) be a significant departure from the current market design

(d) carry several risks – including chilling investment signals and undermining confidence in the market.

2.22. In the Peak Capacity paper, the Authority set out our ambition to accelerate demand response participation. This included considering trials and regulatory sandboxes to explore barriers and opportunities. We are now working with market participants on these options through our Power Innovation Pathway. With regard to our existing demand response mechanisms, the Authority decided to investigate some incremental changes to better reflect operational requirements of industrial demand flexibility (for example, to better reflect that shutting down a processing unit means that it will not be available to respond for several hours). No changes were proposed to the main intended benefit of these mechanisms – spot price avoidance.

Both MDAG and the Authority agreed on the need for a new reserve product to cover sudden supply shortfalls

2.23. Both the Peak Capacity and MDAG papers recommended the development of a new ancillary service reserve product to cover sudden reduction in generation from intermittent sources. This product should also explicitly include options such as battery energy storage systems (BESS) and demand flexibility.

2.24. The Authority is progressing this work through:

(a) a review of the multiple frequency keeping service

(b) Task Force initiatives exploring options to enhance the contribution of distributed energy resources (DER) at times of peak demand.[12]

Why is this an important issue now?

2.25. Notwithstanding this earlier work, various instances of low residual events (periods where residual generation is below 200MW), and recent further engagement with stakeholders has encouraged us to consider whether the market is procuring an adequate level of demand flexibility.

Our electricity system is becoming more intermittent

2.26. Our electricity system is changing. As more New Zealanders switch to electricity for their energy needs, and as the uptake of digital services increases, more generation is required to meet the increase in electricity demand.

2.27. Looking ahead, we expect most of the new generation capacity to come from intermittent sources. As this new generation replaces thermal generation units, and due to the ongoing tightness in natural gas production, the share of intermittent generation (solar and wind) in the system increases.

2.28. This creates a growing need for other resources to provide the flexibility required to compensate for short-term variability in output (eg, when wind does not blow, and sun does not shine). Changing weather patterns and climate change exacerbate this risk and make it harder to predict and manage generation fluctuations.

2.29. As the system becomes more reliant on these intermittent renewable resources, volatility in wholesale electricity spot prices, which have historically been relatively stable, is expected to increase.

2.30. The Authority has several initiatives underway to ensure that we have the settings right for security of supply, including through greater use of flexibility services:

(a) Our *Keeping the lights on* page on our website aims to provide information and data about the work underway to ensure New Zealanders have a reliable and continuous power supply.

(b) Through our multi-year Future Security and Resilience programme, we are also taking a forward-looking approach by enabling new technologies, addressing security and resilience risks and supporting building a power system that is reliable, flexible and future focused.

(c) As part of the Task Force work programme we are also progressing a number of initiatives to enable effective market competition and give consumers options as the power system continues to evolve, including through the development of standardised flexibility hedging products, and through this initiative to enhance incentives for industrial demand flexibility.

The sector expects demand response to be better utilised

2.31. Ongoing peak capacity issues over recent years, and the exceptionally high prices during winter 2024, emphasise the importance of using all available tools to promote reliability. This includes considering contingent recommendations from

[12] These initiatives include proposals to require distributors to pay a rebate when consumers supply electricity at peak times and to require more retailers to offer time-of-use pricing. More information is available on the Authority's website at Energy Competition Task Force | Our projects | Electricity Authority.

MDAG, such as whether a last-resort scheme like Australia's RERT needs to be further explored.

2.32. There remains a concern, both within the sector and among the general public, that demand response is currently underutilised. There is also a view in the sector that procuring an adequate level of demand flexibility to support the efficient and reliable operation of the electricity market could improve outcomes for consumers.

2.33. We expect the potential for demand flexibility to increase. This is linked to the growth of DER, expected connection of new, large electricity consuming loads (eg, data centres), and electrification of process heat. We also expect the continued maturity of demand-side solutions and improvements to the incentives for flexibility services (including as a result of this initiative) to lead to growth in the potential for demand flexibility from industrials and other consumers.

2.34. As this scenario materialises, we need to ensure that we have a clear view on the opportunities demand flexibility presents to the market, how these could best be enabled, and how the market and the Authority can ensure that this happens.

3. Scope and approach

Industrial demand flexibility can be complex, but has potentially significant benefits for the electricity system and consumers

3.1. All types of consumers can provide demand flexibility. This initiative focuses on the incentives for large direct-connect industrial consumers, as well as medium-sized commercial and industrial consumers that are not directly connected to the transmission system, but have large, disaggregated loads (eg, supermarkets). Collectively, we refer to these customers as 'industrials', or 'industrial consumers' for the purposes of this initiative.

3.2. As large loads, industrials have a large potential for flexibility – and have shown they can provide it. This includes response to a price signal (such as to the regional co-incident peak demand charge under the old transmission pricing methodology), or through load shifting to aid local network congestion. However, this potential flexibility is not necessarily low-cost. Industrials have a range of operational characteristics that means that there are trade-offs for accessing flexibility:

(a) **Industrial processes may be slow to ramp on and off**, so the disruption for a short period of demand response is potentially large. For some industrials there is very little load that can be removed from service without reducing output for many hours.

(b) **Adjusting electricity use often directly impacts productive activity**. This means that if an industrial reduces their electricity demand, they produce less. This can have flow on effects for business revenue, and more broadly for the New Zealand economy (and particularly exports). The Authority is aware that for some industrials, the vast majority (>90%) of the consumers' load is directly involved in producing output. This leaves a small proportion available for demand flexibility without potential significant cost.

3.3. Industrial demand flexibility will not be the most efficient form of flexibility in all situations. Given the trade-offs and complexities highlighted above, industrial demand flexibility may be one of the more expensive forms of demand flexibility when considered alongside other consumer segments.

3.4. By contrast, the use of controllable load (generally hot water control) comes at very low marginal cost to consumers. Accordingly, it should generally be dispatched ahead of industrial demand flexibility.

3.5. The trade-offs outlined above mean that we need to take care to ensure the electricity system does not drive behaviours that undermine economic activity and export earnings. This would be inefficient from an economy-wide perspective.

3.6. Notwithstanding these trade-offs and challenges, industrial consumers continue to be of particular interest for several reasons:

(a) There is only a relatively small number of industrial consumers, and they account for a significant proportion of electricity demand. Targeting them can then deliver a significant contribution to demand flexibility, while also being administratively less burdensome than for other types of consumers.

(b) Several industrials have also been involved in conversations about demand flexibility for a long time. This means that they could be more ready to engage with new mechanisms and deliver benefits earlier than other consumers.

(c) It could be possible to leverage mechanisms and capabilities developed for industrial demand flexibility for other participants, including aggregators of smaller consumers and DER.

(d) While existing wholesale market mechanisms are available for industrial demand flexibility, participation has been limited.

3.7. With the prospect of new loads being connected and continued technological developments, getting the right incentives in place now for industrial demand flexibility could provide significant future benefit to the market. It could also increase the likelihood that industrial facilities are developed with demand flexibility in mind.

3.8. Together, these factors suggest that we should focus on encouraging industrial demand flexibility ahead of other forms of flexibility (eg, small-scale demand flexibility, batteries, high-cost marginal generation, etc.) only where it makes sense and provides net benefits to consumers. Industrial demand flexibility should be considered as part of a larger ‘stack’ of demand-side flexibility options.

3.9. We recognise that there is likely to be significant potential demand flexibility from other consumers as well as industrials. We welcome any feedback on this point, including on the applicability of the vision and approach proposed in this initiative to other forms of flexibility.

This workstream focuses on intra-day flexibility by industrial consumers

3.10. We have focused on short-term flexibility, particularly intra-day peaking. We consider this direction from the Task Force is appropriate because it:

(a) has relatively minor impact on economic activity (but not negligible). This is particularly the case if demand flexibility providers receive payment for their activities. On the other hand, longer-term or seasonal demand response, while possible, requires more substantial and prolonged reductions in demand

– and can therefore come at a high cost to productive economic activity, employment, and exports

(b) reflects the growing need for intra-day flexibility to manage variability in the power system. This includes during periods of short-term supply limitations that can occur outside of dry year events

(c) is most likely to coincide with high-priced periods, which could create a situation when the value of the industrial output or process is less than the cost of consumption.

3.11. Recent events have shown that prolonged and/or involuntary demand response can have substantial impact on the New Zealand economy. For instance, MBIE's recent December 2024 New Zealand Energy Quarterly[13] highlighted a 9% reduction in demand from industrial consumers compared to the same period in 2023. This is in part due to some industrial closure (such as Winstone Pulp), but also due to seasonal demand response arrangements.

3.12. This demand reduction included reduced output from the New Zealand Aluminium Smelters (NZAS) Tiwai Point smelter under its demand response agreement with Meridian. This agreement resulted in a reduction of alumina import and aluminium export cargo by about 87,000 tonnes in the six months to December 2024. Additionally, reduced output from Methanex contributed to a 17% reduction in trade through Port Taranaki in 2024.[14]

3.13. Seasonal demand response is currently provided under commercial arrangements with individual consumers. In these instances, the consumer has agreed this is appropriate in the context of their overall energy supply arrangements.

3.14. Due to the more bespoke nature of longer-term demand response arrangements, the Authority considers these should continue to be managed under bilateral arrangements determined on commercial terms between the parties, while having regard to the impacts on economic activity.

3.15. We welcome any feedback on this assessment and any thoughts on the opportunity costs associated with industrial demand flexibility and the various ways in which it could support security of supply while also minimising economic impacts.

Approach

3.16. This initiative provides an opportunity to take a fresh look at current and potential industrial demand flexibility to determine whether our market settings need to change, while considering the insights from previous work.

3.17. A key part of this is determining why the existing market arrangements are not achieving the level of demand flexibility that many have expected to occur. This includes considering the question of whether price avoidance should continue to be the key market mechanism for incentivising demand flexibility, or whether some extra payment could be efficient and ultimately provide a net benefit to consumers.

3.18. Our approach to considering industrial demand flexibility is summarised below. We have set out a draft roadmap of actions we plan to take over the next five years to

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[13] MBIE, *New Zealand Energy Quarterly (December 2024)*, 2025.

[14] Energy News, *Spring demand slump 'alarming' sign of de-industrialisation,* 7 April 2025.

deliver on our proposed vision for industrial demand flexibility. This roadmap is informed by our consideration of the potential for, and barriers impeding, industrial consumers' intra-day flexibility.

4. Existing use of, and potential for, industrial demand flexibility

4.1. Understanding the potential for industrial demand flexibility is necessary to assess the effectiveness of existing mechanisms and consider further potential action.

We see two 'types' of demand flexibility

4.2. We consider that categorising demand flexibility into two key types can offer a helpful lens through which to consider the need for further action:[15]

(a) **Type 1 'implicit' demand flexibility:** this occurs when consumers adjust their consumption in response to price signals. This may happen in response to price signals in a customer's retail contracts, or high spot or transport prices for customers with exposure to the wholesale market. Consumers are not paid for this form of flexibility – the benefit they receive is avoided energy costs.

(b) **Type 2 'explicit' demand flexibility:** this involves a consumer reducing their consumption by a defined amount in response to an instruction from a supplier or the system operator, or when a consumer chooses to on-sell electricity previously purchased for their own use, in return for an agreed payment.

4.3. These types are not necessarily binary, but they do provide a useful way to classify and consider different barriers and issues associated with each form of flexibility.

The electricity market is orientated to support type 1 demand flexibility

4.4. Type 1 flexibility is the main way through which demand flexibility has been integrated into the New Zealand market. Existing mechanisms include DD and differential pricing in retail contracts, which enable customers to respond to wholesale energy and network price signals.

4.5. Despite efforts to encourage greater participation in DD, only one industrial has participated in the mechanism to date – the Norske Skog Tasman mill, which participated from 2014 until its closure in 2022. DD is, however, used by other facilities such as grid-connected BESS.

4.6. Retail contracts for larger consumers generally feature variable pricing, such as time-of-use tariffs. However, these price signals tend to be muted because of risk management (hedging) by retailers. This means that most consumers do not see the short-term spot price signal that might incentivise 'implicit' demand flexibility. In addition, many customers prefer to pay a higher price overall, rather than actively manage their demand in response to price movements. It is difficult to assess the

[15] These two key forms of demand response are widely used, including by the International Energy Agency: https://www.iea.org/energy-system/energy-efficiency-and-demand/demand-response.

effectiveness of these arrangements in incentivising demand flexibility, given there is no way to determine what consumers might otherwise have done.

Other work programmes are considering type 1 demand flexibility

4.7. Type 1 demand flexibility relies primarily on the effective wholesale and network price signals. Recent work by the Authority has focused on these aspects through:

(a) **Reforming distribution pricing** to deliver better outcomes for consumers and help manage how much investment in network infrastructure will be required. This includes encouraging distributors to apply time-of-use pricing for all individual connection points.[16]

(b) **Increasing scarcity prices** in the spot market, with these prices now at levels similar to estimates of the value of lost load (VoLL). This ensures spot market prices are not artificially low during scarcity conditions and more effectively signal the value of additional supply (including demand flexibility).[17]

(c) **Requiring major retailers to offer time-of-use pricing** for all consumers (under a separate Task Force initiative), to encourage consumers to shift their consumption away from peak times when doing so would be efficient.[18]

Type 2 demand flexibility is often in the form of contracts

4.8. While less prevalent, there are also examples of type 2 demand flexibility in New Zealand. These include contracts with retailers and network businesses and can take the form of physical or financial (hedge) contracts. These contracts provide incentives (eg, lower contract prices) to consumers in return for the retailer or network business asking them to reduce their demand at times in accordance with the terms of the contract.

4.9. The best-known example of this is the Meridian contract with NZAS for the Tiwai Point aluminium smelter. This contract enables Meridian to call on 25MW to 185MW of demand response in specified circumstances, which provides for seasonal demand response or flexibility.

4.10. Various retailers, network businesses and third-party aggregators have also sought to better understand the potential for and value of type 2 demand flexibility through pilots and trials. These have tended to focus on managing aggregations of smaller consumer demand but have learnings for consumers of different types and sizes.

4.11. The Energy Efficiency and Conservation Authority (EECA) with the Electricity Engineers' Association (EEA) recently published their Flextalk flexibility scan, which includes 98 projects completed or underway in New Zealand and internationally.

16 See https://www.ea.govt.nz/industry/distribution/distribution-pricing/.

17 See https://www.ea.govt.nz/projects/all/pricing-in-a-renewables-based-electricity-system/consultation/update-to-scarcity-pricing-settings/.

18 A consultation paper was released in February 2025 in relation to this and a related Task Force initiative, see https://www.ea.govt.nz/projects/all/energy-competition-task-force/consultation/new-ways-to-power-electricity-consumers/.

We consider there to be greater value in focusing on type 2 demand flexibility in this work

4.12. This industrial demand flexibility initiative focuses on unlocking type 2 demand flexibility, specifically in the context of intra-day flexibility services. This is a shift in approach from the Authority's previous focus on type 1 demand flexibility.

4.13. We consider type 2 demand flexibility to offer the most significant opportunities to improve incentives for industrials, particularly as it has been relatively unexplored, in terms of regulatory settings and incentives, in New Zealand to date.

4.14. This assessment is based on anecdotal evidence, stakeholder views, and the limited participation by industrial demand response in DD and instantaneous reserves services. It also acknowledges the progress already made and underway to encourage type 1 demand flexibility.

4.15. Given the work already progressing on type 1 demand flexibility, and the benefits that price-insensitive loads could provide to the market during peak demand periods, this initiative primarily focuses on type-2 demand flexibility (ie, where consumers receive additional payments).

4.16. Specifically, our focus is on identifying mechanisms to incentivise industrial consumers to reduce demand when the value of their industrial output is less than the cost of producing electricity. This is expected to be when spot prices are at more extreme levels, reflecting very high demand and low supply. We have generally referred to this as 'short-term flexibility'.

4.17. Separately, the Authority is undertaking other work to enhance hedging behaviour and markets, including through package one of the Task Force. This is because hedging by retailers can promote the long-term interests of consumers by enabling efficient decisions and fostering competition and transparency.

4.18. However, hedging can also mute price signals for consumers and reduce incentives for demand flexibility. We recognise that this could be seen as an inconsistency. Package two of the Task Force is ultimately about providing consumers with more choices about how they manage their electricity supply. We do not consider that enabling more industrial demand flexibility should occur at the expense of industrials' willingness and ability to hedge.

What is the existing potential for industrial demand flexibility?

4.19. Before considering whether and how to incentivise more short-term flexibility by industrials, we have sought to identify the potential demand flexibility that may be currently available.

4.20. A large proportion of consumers could technically provide demand flexibility. For example, Williams and Bishop (2024) identified that up to 69% of all New Zealand demand may be technically capable of providing demand response.[19] This included resources available with high, medium and low confidence, and consumers of all types (including industrials).

[19] Williams B and Bishop D, *Flexible futures: the potential for electricity demand response in New Zealand*, Energy Policy, Vol 195, 2024

4.21. However, not all technical capability will translate into potential demand flexibility. This requires consideration of consumers' willingness to make this capability available, which involves considering the incentives, trade-offs, and other complexities.

4.22. Willingness considers the consumer's actual and perceived costs and benefits:

(a) **Costs and risks** including foregone production; costs of equipment and technology; development and learning of processes, training personnel to enable demand flexibility; opportunity costs of being available to provide flexibility; and transaction costs.

(b) **Benefits** including avoided energy costs; any payments for providing flexibility; reduced climate emissions; and reputational benefits associated with social and corporate responsibilities.

4.23. Unlike electricity generators, most consumers do not focus on the electricity market. Instead, they focus on the specific market into which they supply goods and services. As a result, even if demand flexibility could increase profits, on its own, it may not be a sufficient incentive. This is particularly true for those whose electricity costs make up a relatively small portion of their overall business' costs.

Estimated currently available industrial demand response represents around 6% of typical peak demand, and 2% of winter peak demand

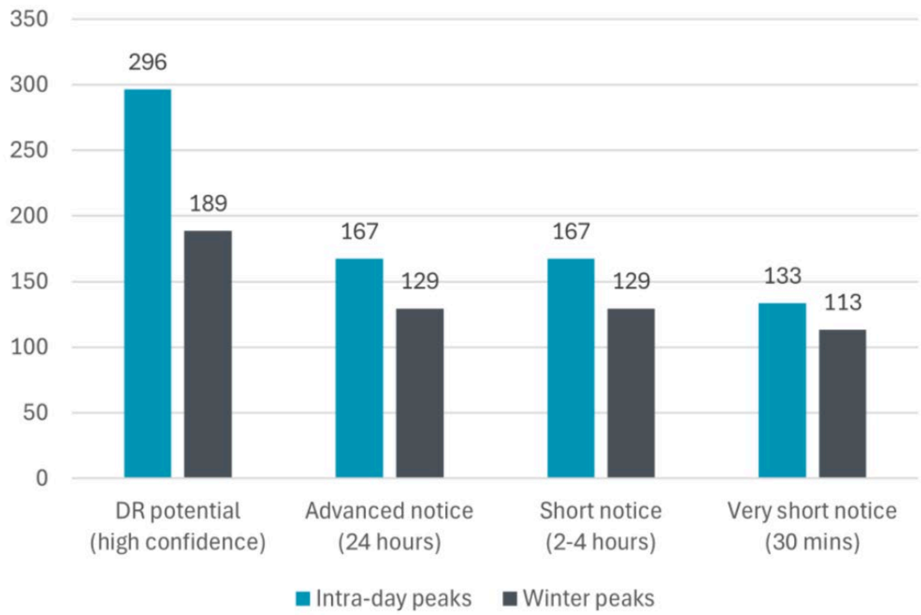
4.24. The Authority engaged Sense Partners to undertake an assessment of the current short-term demand response that industrials may be both technically capable of and willing to make available (Appendix C). The report estimated that existing industrials could provide up to 189MW of technical demand response in winter (when primary sector production is lower) and up to 296MW at other times of year.[20]

4.25. More specifically, Sense Partners estimated that industrial consumers could be willing to provide up to 130MW of demand response for intra-day flexibility in winter and up to 168MW at other times of year (Figure 1 below). These figures were determined using a high incentive level, of approximately 20-30% of the industrial's electricity costs. These numbers considered several proxies to estimate consumers' willingness to offer this kind of demand response.

4.26. This level of flexibility would be less than what is typically seen as the size of the opportunity within the sector, only accounting for about 2% of typical winter peak demand and 6% at other times of year.

[20] Please note that this quantity excludes Tiwai's demand response arrangement with Meridian as this is not a short-term response, and it also does not include confirmed but not operating loads (such as NZ steel arc furnace).

Figure 1: Assessed levels of current potential demand response, MW of demand response (Sense Partners)



Note: *Response by notice period is potential adjusted for survey evidence on actual willingness to response (share of peak MW) given a 20-30% reduction in electricity bills.*

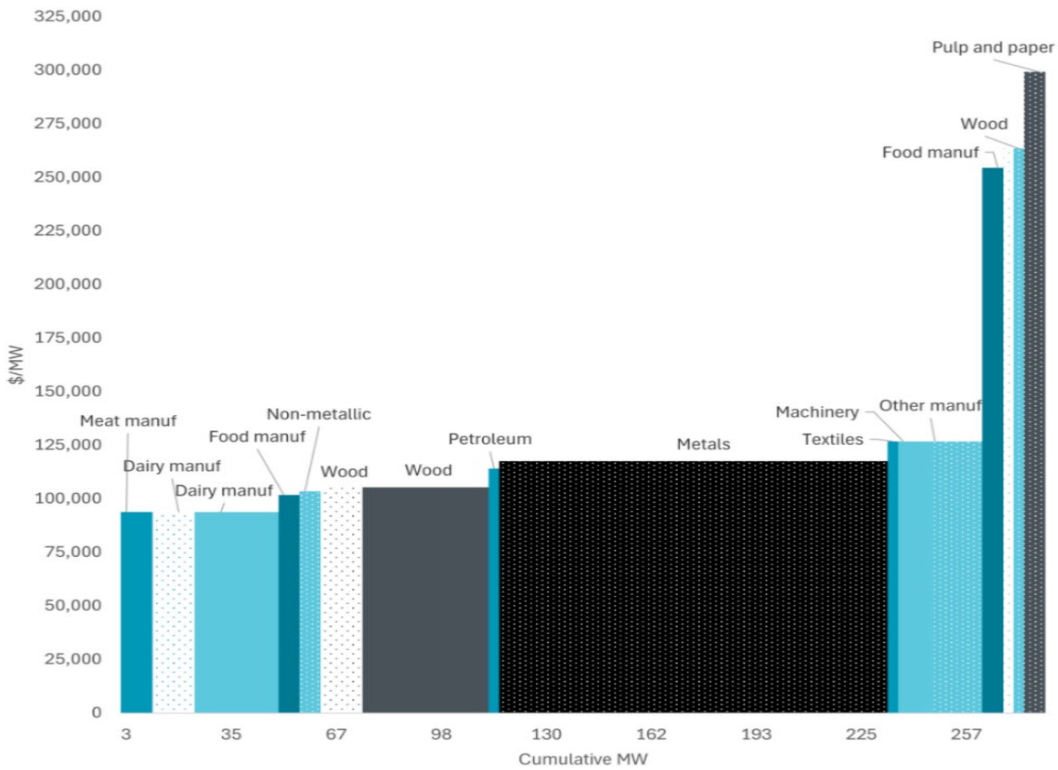
4.27. Sense Partners also considered the level of industrial demand response that may be currently available in response to sufficient financial incentives. These calculations did not exclude any potential demand response due to the degree of confidence about its technical potential. This analysis indicates that:

(a) industrial demand flexibility may require relatively high incentive payments, but

(b) incentives to induce demand flexibility could be much lower than the incremental cost of additional peak (supply-side) capacity.

4.28. This analysis indicates that the volume of current potential industrial demand flexibility may be modest (Figure 2 below). However, it also highlights an opportunity for industrial demand flexibility to help manage short, infrequent periods of acute system stress. At these times, even relatively small volumes can make a material difference to the cost and reliability of supply.

Figure 2: Industrial demand flexibility conditional on incentive payments (Sense Partners)



Note: *Demand flexibility potential shown here is for intra-day peak MW (not winter intra-day peak). Block patterns indicate confidence levels assessed in Williams and Bishop (2024). Solid blocks are high confidence; patterned blocks with solid background are medium confidence; and blocks with white backgrounds and dots are low confidence. These figures are a high-level estimate of how much demand response might be achievable for a given level of incentive (in capacity terms) and do not reflect the value of demand response.*

4.29. The Authority acknowledges that these estimates will be lower than many stakeholders expect, and that different analysis may indicate different volumes of potentially available demand response. However, we consider that Sense Partners has set out a robust framework for a credible order-of-magnitude assessment of the current scale of industrial demand flexibility potentially ‘on the table’.

4.30. We do not have visibility of the full extent to which industrial demand flexibility is already currently activated via bilateral arrangements in New Zealand. We also do not have a comprehensive picture of the willingness of each individual consumer to provide intra-day flexibility. Individual consumers will be influenced by unique factors, such as those that led to the agreement between NZAS and Meridian referred to previously in this paper.

4.31. Notwithstanding this, we believe a ‘better’ estimate of potential demand flexibility is unlikely to be an order-of-magnitude different from Sense Partners’ estimates. Therefore, we consider these estimates to be useful when considering initiatives to enable more demand flexibility from industrial consumers in the near-term.

4.32. The Authority welcomes feedback from stakeholders on the level of existing potential demand flexibility, including evidence where possible. In particular, we welcome any details on demand response arrangements that have already been contracted. We also welcome feedback on potential demand flexibility that may be available from other consumer types.

What is the potential for industrial demand flexibility in future?

4.33. The current potential for industrial demand flexibility appears to be modest, but this is likely to increase over time. The Ministry of Business, Innovation and Employment (MBIE) provides forecasts of electricity demand and generation for the period to 2050 under a range of scenarios. Its July 2024 forecasts indicate total electricity demand in New Zealand is likely to grow by between 35.3% and 82.0% by 2050.[21] It will reach 62.1 terawatt hours (TWh) in the reference scenario – around 50% higher than current levels. Demand growth is expected across all consumer types, including commercial and industrial.

4.34. MBIE also forecasts between 5.4 and 15.1 gigawatts (GW) of new supply capacity will be required by 2050. The majority of this expected to be wind and solar generation due to the relatively lower costs of these technologies.

4.35. Along with forecast demand growth, we expect that continued technological developments and effective incentives, including through the actions set out in our roadmap under this work, to increase the potential for demand flexibility in future.

4.36. Growth in demand by industrials is expected to include both new consumers and existing consumers electrifying their loads. For example, Datagrid NZ plans to open the first phase of its new data centre at Makarewa by 2028 and Fonterra has announced plans to invest in electric boilers as part of upgrades to its existing facilities by 2027.

4.37. Data centres are often cited as a growing type of large energy consuming load type that 'should' be capable of providing a degree of flexibility. However, the Authority is aware that among data centre operators there is likely a wide range of potential willingness to provide demand flexibility, reflecting considerations such as the needs of the data centre's customers and the portfolio in which the data centre operates.

We intend to take an active approach to unlocking industrial demand flexibility and developing the market, given this uncertainty

4.38. The Authority has not sought to explicitly forecast future industrial demand flexibility potential. However, we considered the likely scale of potential demand flexibility into the future, based on MBIE's forecasts and Sense Partners' findings. If demand growth reflects more optimistic scenarios and/or if technological developments make providing demand flexibility cheaper, then there could be a possible step change in the scale of potential industrial demand flexibility.

4.39. Establishing effective incentives will also increase this potential, as consumers and aggregators are better able to identify the benefits of enabling this capability. Even a more conservative outlook suggests potential demand flexibility could increase, although remain relatively modest compared to future overall demand levels.

4.40. This uncertainty suggests that a 'set and forget' approach to activating demand flexibility is not appropriate. We want to ensure that market settings are scalable

[21] MBIE, *Electricity Demand and Generation Scenarios: Results summary*, July 2024.

and remain fit-for-purpose over time. This will help ensure that the electricity market maximises the benefits received from this flexibility.

4.41. Settings need to be in place early, to enable consumers to make choices about how they engage with the electricity market – including ensuring that industrials have the necessary transparency and certainty about potential reward for providing demand flexibility to be able to take informed investment decisions over the coming years.

5. What are the barriers to more industrial demand flexibility?

5.1. Previous reports, including MDAG's *Price discovery in a renewables-based electricity system*[22] have discussed the conditions that need to be in place (or barriers overcome) to enable greater demand flexibility.

5.2. Potential barriers to greater use of demand flexibility generally relate to:

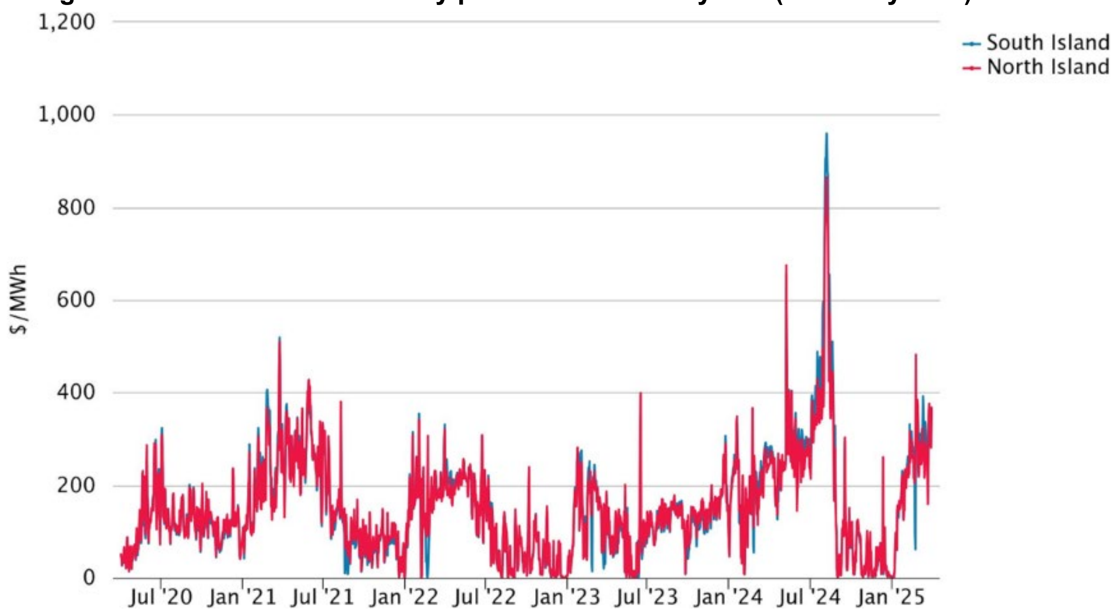
(a) insufficient incentives for its provision, or purchase

(b) impediments to its transaction such as the absence of trading platforms, limitations on participation, insufficient information, and the need to overcome technical participation challenges such as measurement.

Current pricing arrangements do not provide sufficient incentives.

5.3. New Zealand has experienced periods of high wholesale electricity prices, such as during July and August 2024. Historically, however, electricity prices have been relatively stable in real terms (as shown in Figure 3) and represented a low proportion of costs for many commercial consumers.

Figure 3: New Zealand electricity prices in the last 5 years (Authority data)



[22] MDAG, Price Discovery in a renewables-based electricity system, 2023, Appendix A.

5.4. As a result, the potential savings from demand response have been modest and may not be enough to incentivise significant volumes of industrial demand flexibility.

5.5. As noted above, many industrials (and other consumers) are supplied under arrangements in which they are partially or fully hedged against volatility in the spot market. The Authority encourages prudent risk management by market participants.[23] However, this inevitably mutes the incentives they have to provide demand flexibility under existing settings and is likely to reduce its potential.[24]

5.6. Potential demand flexibility providers also note that they face upfront costs (eg, control systems, operational process enhancements, telemetry) to ensure they can manage their demand in accordance with a flexibility contract or mechanism. However, under existing demand response mechanisms they may not be able to recover these costs.

5.7. Industrials exposed to wholesale price signals indicate that uncertainty in spot price outcomes disincentivises demand response under current settings. This is because enacting demand response, or other changing system conditions, can reduce the spot price to below the level at which the activated demand was efficient and of value to the provider – creating a 'first mover' problem.

5.8. To illustrate this problem in a simplified way: an industrial (Firm X) that participates in a type 1 demand response mechanism (price avoidance) chooses to suspend production to avoid a high-spot price. If, for example, this happens during a situation of low residual event, where even a few MW can make a difference in the supply stack and prices, this lowers the spot price for all consumers. Firm X avoids paying the energy cost for the period in which it has responded but had to suspend production. Other consumers maintain production, paying the lower energy price.

5.9. In this case, Firm X is not the primary beneficiary of the activity. Instead, the primary beneficiaries are other consumers who choose to continue production and receive the lower energy price. Firm X's actions have a material benefit to other participants, but firm X is not in any way rewarded for providing that benefit. Firm X will likely undersupply its demand flexibility because in a type 1 only scenario there is a missing money problem.

5.10. There are also limits to the flexibility that demand can provide, which makes the impact of these price signals more acute. Demand flexibility is more akin to energy storage than generation, in the sense that it is energy limited. If the consumer chooses the 'wrong' time to activate the demand flexibility, it can miss out on a more valuable opportunity. This also means that the market may not achieve the full benefit of this flexibility.

5.11. We note that submissions (mainly from generator-retailers ('gentailers') to MBIE's *Measures for transition to an expanded and highly renewable electricity system*

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[23] For example, the Authority has facilitated the development of standardised flexibility products through the Co-Design Group as part of Task Force initiative, and in 2024 improved hedge disclosure obligations to support participants' ability to assess prices and negotiate contracts. For more information, refer to https://www.ea.govt.nz/about-us/our-people/our-advisory-and-technical-groups/standardised-flexibility-product-co-design-group/.

[24] We note that risk avoidance mechanisms (such as contract for difference) can still operate in a way still create an inventive for consumers to reduce demand. However, by removing the exposure to spot prices, they do reduce the strength of the price signal to the consumer. They also may reduce the willingness of the consumer to engage with the electricity market.

paper[25] proposed that the market is working. Those submitters stated that existing market or contractual arrangements between suppliers and consumers were sufficient to enable significant demand response, and no further incentives are needed. However, given the barriers to and levels of demand flexibility set out above, we are not satisfied that the market has sufficiently harnessed the benefits that demand flexibility can provide.

5.12. For instance, we have heard from industrials that gentailers are often not offering sufficient value in contracts to make the demand response worthwhile. Therefore, they have expressed a preference to be paid for demand flexibility through the wholesale market or, at least, in a manner different to the way in which retailers currently pass through these price signals.

5.13. Our view is that there is probably a balance between these perspectives. We see that bilateral contracts between large consumers and retailers will be suitable for some consumers and types of demand flexibility, including seasonal demand response. This is because these agreements can be better tailored to the industrial's bespoke requirements.

5.14. Market mechanisms may be required to enable demand flexibility from other consumers. However, any market interventions need to be proportionate to the scale of potential demand flexibility that could be activated, and the benefit it provides.

Buyers of flexibility may not have sufficient incentives or face other barriers

5.15. The key buyers of flexibility services are retailers seeking to mitigate exposure to high prices, electricity distribution businesses (EDBs) and the grid operator seeking to manage congestion in their networks, and the system operator to support system security and reliability.

5.16. The Authority is aware that some retailers are facing challenges sourcing adequate 'shaped' hedging products.[26] This indicates that there may be an opportunity for demand-side flexibility to be enabled via hedging products. This opportunity is likely to increase in future as variable renewable generation makes up an increasing share of supply and drives greater volatility in intra-day electricity prices.

5.17. As noted by MDAG, in some situations, gentailers do not face adequate incentives to buy or offer flexibility services, as doing so may reduce the overall profitability of their portfolio. [27] For example, reducing demand at a time when a gentailer is a net seller in the market can result in overall lower profits for the gentailer. This can contribute to the limited availability of shaped hedging products for other retailers, if larger participants in the market are not incentivised to offer them.

5.18. In February 2025, the Authority released a consultation paper outlining its proposal, under a separate Task Force initiative, to introduce mandatory non-discrimination obligations which the large gentailers would have to follow. While this proposal seeks to create a level playing field in the trade of hedge contracts, it does not

25 MBIE, Measures for transition to an expanded and highly renewable electricity system – summary of submissions, 2024.

26 The Authority's risk management review found that the market for shaped cover is neither deep nor liquid. For more information, refer to https://www.ea.govt.nz/projects/all/risk-management-review/.

27 MDAG, Price Discovery in a renewables-based electricity system, 2023, Appendix A, p117.

specifically address the situation where a gentailer does not have any incentive to offer a product – to its own retail arm or a competitor.

5.19. Separately, under settings imposed via price quality regulation, regulated networks theoretically face equivalent financial incentives to use solutions that primarily require operational expenditure (typically referred to as 'non-network solutions') and capital expenditure ('network solutions'). Exempt networks are also able to adopt the most efficient solution to manage network demand.

5.20. Several EDBs and Transpower have trialled, over several years, the use of demand flexibility as a form of non-network solution to manage congestion or address other network needs. However, network business' consideration of non-network solutions has not yet matured on par with more traditional network solutions.[28] The actual number of flexibility solutions implemented by EDBs over the last decade remains small, and Transpower has never entered into a grid support contract.

Other barriers

5.21. For demand flexibility to be worthwhile to a consumer or flexibility provider, it may require 'value stacking' across multiple potential buyers of flexibility. For example, the same demand flexibility activity may provide a non-network solution for an EDB, reduce wholesale spot prices, and reduce a consumer's exposure to high energy prices. However, to realise this opportunity the consumer or flexibility provider needs to engage with multiple parties and comply with the requirements of multiple arrangements, the cost of which may negate the benefit of providing the service.

5.22. In the case of a flexibility provider looking to aggregate demand flexibility across multiple consumers, there is also the added cost and effort of reaching agreements with those customers and developing any platforms or tools to manage the service.

5.23. Similarly, it can be difficult for parties seeking to purchase flexibility services if there is not an existing market. If there are no existing demand flexibility providers, a commercial purchaser would have to put significant effort into developing requirements, procedures and payment structures before it could access any service.

5.24. Existing market structures do not readily enable demand flexibility in all cases. This is because the existing system and market arrangements were developed with a focus on supply-side resources competing to provide energy to a largely passive demand side.

5.25. Existing demand response mechanisms were not initially designed to enable participation by third-party flexibility service providers. For example, while third-party flexibility providers are permitted to participate in the DD mechanism, the market settlement and clearing arrangements have been established on the premise of one retailer responsible for managing each customer connection point. This means it can be difficult for non-retailer flexibility providers to realise the full value of the demand response.

[28] As part of the 2025 reset of the default price-quality path for regulated networks, the Commerce Commission has approved an innovation and non-traditional solutions allowance for EDBs. More information is available on the Commerce Commission website at https://comcom.govt.nz/regulated-industries/electricity-lines/projects/2025-reset-of-the-electricity-default-price-quality-path.

5.26. The technical and compliance requirements associated with existing mechanisms were also designed with traditional supply-side resources in mind and may not readily support participation by consumers who have designed their plant to produce goods or services, not to participate in electricity market mechanisms. More fit-for-purpose requirements have the potential to reduce the cost of providing industrial demand flexibility.

5.27. However, we also recognise that from the perspective of networks or the system operator seeking to use demand flexibility, there needs to be sufficient technical and performance requirements to ensure the services can be delivered when needed, and do not have any unintended impacts on the operation of the network or system more broadly.

Questions

Q1. Do you agree with our approach of focusing on industrial demand flexibility as an early initiative to enable demand flexibility more broadly? Why/Why not? Do you have any information to indicate that demand flexibility from other consumer types may be more readily accessed?

Q2. Do you agree with our estimates of the potential industrial demand flexibility capacity available in New Zealand currently and into the future? Why/why not? Do you have any evidence to support a materially different estimate?

Q3. Do you agree with our focus on intra-day demand flexibility for this initiative? Why/why not? What other approach would you suggest?

Q4. Are there any other ways that currently enable industrial demand flexibility in New Zealand?

Q5. Do you agree with our description of the barriers affecting the provision of industrial demand flexibility? Why/why not? Are any other barriers relevant to the provision of demand flexibility from other consumer types?

Q6. Do you agree that existing incentives and contracts for demand flexibility are resulting in inefficiently low levels of demand flexibility?

Q7. Are you aware of any additional barriers to enabling more industrial demand flexibility?

6. Vision for industrial demand flexibility

6.1. We have developed a vision to help us identify the purpose of any work to stimulate further demand flexibility, and to ensure that this is focused on actions that will result in net benefits to consumers. We propose the following vision for industrial demand flexibility, aligned with the Authority's main statutory objective:

Vision	***To enable efficient flexibility through industrial demand flexibility so it achieves long-term benefit for consumers by promoting a competitive, reliable, and efficient electricity industry.***

6.2. Our vision also places industrial demand flexibility within a wider efficient system of flexibility: we should be promoting proportional demand flexibility where that is the most efficient flexibility option, rather than aiming to 'achieve' an arbitrary MW target of response from industrials. Under current settings, it is arguable that demand flexibility is under-incentivised and that more should be done. However, we also want to avoid a future state where demand flexibility is overly incentivised to participate in the electricity market and potentially displaces more efficient investment in other assets (such as grid-scale BESS).[29]

6.3. When ‘efficient’ demand flexibility is activated, there can be a net benefit to all consumers, even where the demand flexibility provider receives a payment in addition to the value of avoided energy consumption. However, to be regarded as ‘efficient’ there would need to be limits to the additional payment that providers would receive. Our view is that efficient demand flexibility occurs when:

(a) the value of the demand flexibility to consumers (in aggregate) **is greater than** the cost of the demand flexibility; and

(b) the cost of the demand flexibility **is less than** the cost of alternatives (eg, additional supply or network investment).

6.4. Where the provision of the demand flexibility is efficient, providers should therefore be able to receive some of the value to the overall market of the services they provide. However, this should be less than the total value to ensure benefits are realised by consumers broadly.

6.5. We recognise that this vision is a change in the Authority’s position on demand flexibility from industrials to date. The focus on long-term benefits for consumers enables consideration of different payment structures for demand flexibility – a short-term incentive may be considered where this is considered necessary to encourage participation, to deliver long-term benefit.

6.6. The Authority's view on what it means in practice to give effect to this vision is set out below:

(a) We recognise that where there are **net benefits to consumers** through lower costs (in the long-term), demand flexibility can be considered efficient.

(b) This could involve **payments to demand flexibility providers in addition to avoided energy costs** – if consumers overall pay less in the long-term.

(c) Demand flexibility should provide services **to the extent that it is efficient** and provides benefit – this vision does not include using demand flexibility to target a certain price outcome, nor a certain level of demand flexibility.

(d) **Barriers to the efficient use of flexibility services should be removed,** where the value to consumers of the demand flexibility over the long-term is likely to outweigh to implementation costs.

(e) So long as it provides net benefits to consumers, **we are agnostic as to how demand flexibility is provided**, including whether via centrally coordinated mechanisms or decentralised; whether the system operator runs a scheme, or it is market-led; and whether a consumer elects to reduce their load or use an alternative energy source to reduce demand from the grid.

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[29] We recognise that investment in BESS and other technologies may also be efficient and appropriate to *enable* demand flexibility. As noted in section 6.6, we are agnostic as to how consumers enable its demand flexibility.

6.7. Our proposed vision allows for the consideration of options that feature any potentially efficient incentive options (eg, 1, 2a and 2b in Figure 4 below). The Authority is agnostic as to how intra-day flexibility services from industrials are enabled to achieve the vision. Options for the future enablement of demand flexibility could include any, or a combination, of the following:

(a) standard and bespoke bilateral contracts

(b) standard and bespoke hedges

(c) enhancements to existing market mechanisms

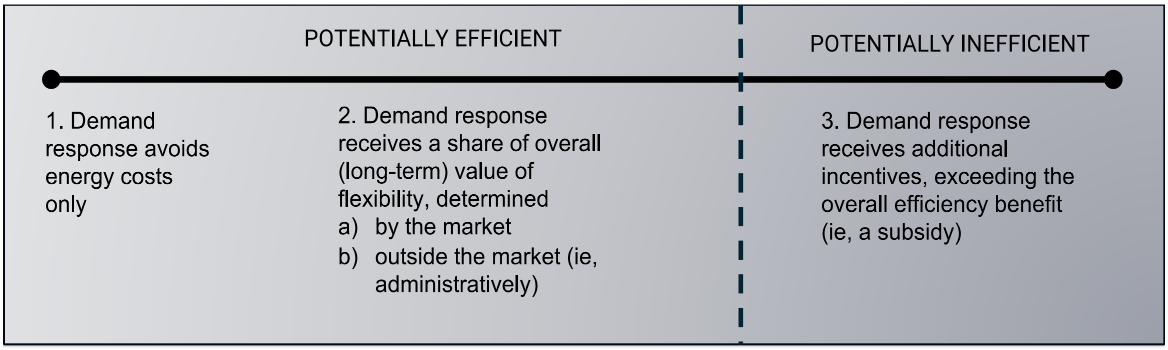
(d) new market mechanisms in addition to or replacing existing mechanisms

(e) new platforms to facilitate trading in flexibility services.

Spectrum of options for demand flexibility incentives

6.8. Different levels of incentive for demand flexibility can be set, reflecting the purpose of the demand flexibility mechanism. These are summarised in Figure 4.

Figure 4: Spectrum of options for demand flexibility incentives



6.9. Examples of demand flexibility mechanisms exist across this spectrum:

(a) Mechanisms that only provide for avoided energy costs (1 in the figure above) include type 1 mechanisms such as DD and retail contracts with variable (eg, time-of-use) prices.

(b) Mechanisms that provide additional efficient incentives set by the market (2a in the figure above) include the NZAS seasonal response contract and instantaneous reserves ancillary service.

(c) Mechanisms that provide additional incentives that are administratively determined (2b in the figure above) but are less than the total benefit to the market (ie, can be considered efficient) include the Singapore Demand Response Programme, which allocates one third of the overall market benefit as an incentive for the demand response provider.

(d) Mechanisms that provide potentially inefficient subsidies (3 in the figure above) typically have a purpose of maximising demand flexibility or achieving a certain level of demand response and include the Californian Demand Response Auction Mechanism, which requires three investor-owned utilities to allocate a certain budget to procure demand response to meet their capacity obligations, regardless of whether they are cost competitive with other supply options.

6.10. Robinson Bowmaker Paul (RBP) has provided an overview of the Singapore and Californian mechanisms as part of their *Demand Response Programmes International Scan* prepared for the Authority.

Applicability of the approach in this paper to other forms of demand flexibility

6.11. We note that while this paper focuses on industrial demand flexibility, the vision and principles it sets out apply to demand flexibility more generally. This initiative has focused on industrial demand flexibility in the first instance, given potential for 'low hanging fruit' from these consumers as set out in section 3 of this paper.

6.12. While we consider that a particular focus on industrial demand flexibility is warranted, we welcome any feedback on this point, including on the applicability of the vision and approach to other forms of flexibility.

Questions

Q8. Do you agree with our vision for industrial demand flexibility? Why/why not?

Q9. Do you believe that this vision is applicable to other forms of demand flexibility, or to flexibility more generally?

Q10. Do you agree with our view that demand flexibility providers should be able to receive payment for providing flexibility services that exceeds avoided energy costs, provided the demand flexibility is efficient (as defined)? Why/why not?

Q11. Do you believe that a different level of payment would be appropriate than what we have defined as efficient? Why/why not?

7. Proposed roadmap for industrial demand flexibility

Overview

7.1. The Authority proposes a range of actions to enable and reward short-term flexibility from industrials. These actions, which form part of our proposed roadmap, focus on:

(a) the scale of potential short-term flexibility services from industrials, and the potential for this to grow over time; and

(b) the identified barriers to the provision of more industrial demand flexibility.

7.2. The proposed roadmap focuses on actions we will take over the next five years to help realise our vision for industrial demand flexibility. It includes short-term actions to be taken immediately and over the period 2025 to 2027, and longer-term actions for 2028 to 2029 and beyond.

Guiding principles

7.3. We have developed a set of principles to guide our proposed actions, which will also inform further development and detailed design (where applicable) of these measures over time.

7.4. These principles have been developed with reference to the Authority's statutory objectives, our proposed vision for industrial demand flexibility, and the Government Policy Statement on Electricity. The principles also include practical considerations (ie, costs) and the broader strategic context in which the roadmap is being developed. The proposed guiding principles are outlined in Table 1, below.

Table 1: Proposed guiding principles for industrial demand flexibility roadmap actions

Principle	Outcomes sought
Enable diversity of parties competing to bring solutions that meet customer demand	• Providers have access to information that enables them to develop business models to provide intra-day flexibility services using industrial demand flexibility. • Competition in the provision of flexibility services is maximised with diversity of parties offering and seeking to purchase flexibility services. • Network business processes enable non-network solutions to compete on a level playing field with traditional network solutions. • Market concentration does not unduly limit liquidity in the trade of flexibility products. • Large consumers, retailers and third-party service providers can all offer services (either themselves, or on behalf of consumers). • Wider competition in the New Zealand electricity market is not distorted. • Efficient incentives are available to all providers of flexibility services.
Ensure the secure and reliable supply of electricity	• Demand response is activated to ensure we limit the amount of unserved energy to economic levels. • Providers have effective incentives to be available and/or disincentives for non-performance. • Network businesses are adequately incentivised to consider demand flexibility as an alternative to network investment. • Service delivery and performance can be forecast and measured with sufficient accuracy. • Providers are given sufficient notice for resources to be available.

Enable efficient operation of the electricity industry and minimise costs for consumers in the long run	• Use of industrial demand flexibility provides long-term value to consumers in aggregate (eg, by deferral of generation and/or network investments, which reduces up front impacts on consumer bills).
	• Pricing is efficient and incentivises entry and consistent provision of demand flexibility over time (ie, pricing covers both operating and capital costs and can provide a reasonable return that, together, do not exceed the value of the demand response to consumers in aggregate).
	• Providers have access to information and services to accurately identify and manage their risks.
	• Triggers for the activation of demand flexibility are set to minimise any efficiency loss.
	• Use of demand flexibility should not:
	  ○ distort wholesale market pricing by incentivising providers to withdraw capacity
	  ○ distort scarcity pricing signals in the wholesale market
	  ○ displace lower-cost energy resources.
	• Incentives for providers should be predictable and ‘first movers’ should not be disadvantaged.

Principle	Outcomes sought
Minimise cost, complexity and effort of participation for demand response providers	• Actions taken to activate demand flexibility are proportionate to the value of any additional demand flexibility likely to be made available – currently and into the future. • Costs and effort of providing or purchasing demand flexibility are minimised and do not exceed benefits. (Costs include regulatory, market systems, participant systems, telemetry, system operations, settlement and reconciliation, etc.) • Where possible, replicable, standardised processes and systems are developed to reduce cost (eg, standard processes for notifying the market of demand flexibility opportunities across all 29 distributors). • Compliance requirements for demand flexibility providers are minimised but sufficient to ensure that competition, reliability and efficiency of the electricity system are not compromised.
Maximise strategic alignment with the broader Task Force and Authority work programme	• Actions to enable industrial demand flexibility are aligned with broader changes in the electricity system, including: ○ alignment (and not duplication) with other reform initiatives ○ the potential for more efficient supply of flexibility by other providers of flexibility services (including aggregations of small consumers' resources) immediately and in the future ○ the potential for demand flexibility providers to value stack across compatible demand response services ○ the evolving needs of the power system and capability of demand response. • We prioritise enduring solutions but remain open to 'learning by doing' where necessary.

Proposed near-term actions

7.5. As previously noted, the estimated scale of potential industrial demand flexibility currently available is relatively modest, and some is already managed under bilateral agreements. However, the potential scale is meaningful, and could contribute to an efficient and reliable market, particularly during peak demand periods.

7.6. In the short term, the Authority has sought to identify relatively low cost, quick to implement measures to activate more existing industrial demand flexibility, where it is of highest value.

7.7. We have identified two actions that we could take immediately and that, if progressed, could be implemented for Winter 2026:

(a) **Immediate action 1: Emergency Reserve Scheme (ERS)**, primarily focused on using demand flexibility.

(b) **Immediate action 2: A standardised demand flexibility product** for intra-day demand response.

7.8. In addition to these, we recognise the latent and growing potential of flexibility services and propose several other short-to medium-term actions (set out in paragraph 7.39 below) to lay the foundations for greater use of industrial and other forms of demand flexibility into the future.

Immediate Action 1: Development of an Emergency Reserve Scheme

7.9. This paper sets out an overview of the reasons why we currently consider that implementing an ERS a prudent and efficient immediate action. Given the importance of such a scheme, and its technical complexity, we plan to release a dedicated consultation paper on proposals to develop an ERS in July 2025.

We expect that low residual events are likely to be an ongoing issue for the next few years at least

7.10. As we have observed in recent years, greater generation intermittency is creating challenges for security of supply, especially during cold, still mornings and evenings. The ongoing challenge is to balance coordination of a wide range of available resources as efficiently as possible for security of supply, while maximising benefits for consumers.

7.11. Transpower's outlook for the 2025 winter period indicates that peak capacity risks, especially during cold snaps, will persist until there is sufficient investment in flexible resources such as batteries, demand response, and peaking generation. The 2024 Security of Supply Assessment indicates that this issue is not likely to resolve quickly, with potential winter peak capacity shortfalls identified in the reference scenario from 2027 onwards.[30]

7.12. There are opportunities for consumers to support the system during these types of events, including by lowering consumption during periods of peak demand and low residual generation, reducing the likelihood of involuntary load shedding.

7.13. MDAG recognised the potential for industrial demand flexibility to contribute to system security and made a recommendation to establish a 'last resort' scheme along the lines of Australia's RERT (recommendation 30). This recommendation was contingent on the Authority being satisfied that the market was not providing, or was unlikely to provide, sufficient demand response to support security of supply.[31]

7.14. The Authority has considered similar ideas before, such as Option K in our Winter 2023 workstream,[32] the CEO Forum proposal for a standby ancillary service,[33] and the interim options in the Peak Capacity workstream.[34]

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30 Transpower, *Security of Supply Annual Assessment*, 2024.

31 MDAG, *Price Discovery in a Renewables-Based Electricity System: Final Recommendations Paper*, 2023, p114.

32 Option K was a proposed mechanism where separate payments outside the spot market could be used to encourage providers to make resource available. For more information refer to our winter 2023 work programme.

33 The CEO Forum (a working group of the CEOs of the six larger generators, four largest distributors, and Transpower), put forward a proposed out-of-market mechanism payment for resources that would be ring-fenced form other market mechanisms. More information is available in this submission to the Authority.

34 More information is available here: Potential solutions for peak electricity capacity issues | Our consultations | Our projects | Electricity Authority

There may be price insensitive, or otherwise non-responsive, load that could be accessed to provide last resort demand flexibility

7.15. The Authority has revisited this issue and recognises that, with adequate incentives, such a scheme could enable access to demand flexibility that would otherwise be inaccessible to the market during periods of tight supply, particularly to help manage the risk of inefficient involuntary load management (ie, disconnection of consumers).

7.16. If designed effectively, industrial demand flexibility has the potential to be an efficient source of last resort 'supply', without materially distorting signals for investment in additional supply. To be efficient, the cost of such a scheme would need to be lower than the value of lost load (VoLL). It should be noted that the current value of VoLL in the Code ($20,000/MWh) has remained unchanged since 2004. The Authority plans to review VoLL to ensure it remains fit-for-purpose.

7.17. The Authority also notes that central programmes can kickstart broader activity in a sector. Enabling industrial demand flexibility to provide emergency reserves may unlock greater potential for the provision of short-term flexibility services, if the scheme is able to cover some or all the upfront costs of enabling the flexibility.

Design features of an Emergency Reserve Scheme

7.18. The Authority is focused on ensuring the design of any such scheme promotes reliability and efficiency in line with our main statutory objective, without distorting signals for investment or impeding competition in the wider market.

7.19. The Authority is currently considering potential design options for an ERS. To provide a clearer picture of our current thinking to stakeholders, we have included a summary of the key features we are contemplating for the scheme (Table 2, below).

Table 2: Overview of Emergency Reserve Scheme

Proposed Emergency Reserve Scheme	
Objectives	We have identified two main objectives: • minimise the likelihood and extent of uneconomic load shedding during periods of peak electricity demand. • build consumer capability to participate in demand flexibility more generally, through organisational capability and investments in equipment.
Key features	• The primary purpose of the scheme would be to provide a block of load that the system operator can manage, ahead of using the existing (involuntary) load management tools. • The scheme would be a last resort mechanism, to be used infrequently. • Industrial demand flexibility would be eligible to participate in the scheme. Demand flexibility from other consumers may also be eligible. • The scheme should reflect the scarcity conditions that the system is under when activated. • Payments to providers under the scheme would not be limited to avoided energy costs but should be efficient.

The Authority's preferred solution to access price insensitive load is a last resort scheme over a centralised 'negawatt' scheme

7.20. We are aware some stakeholders have indicated their interest in a broader paid demand flexibility scheme, such as a 'negawatt'[35] scheme to provide incentives for demand flexibility.

7.21. MDAG was *'of the firm view that is better to solve a niche problem procured as (effectively) an ancillary service, than to force a regulated wholesale 'overlay' which would see regular payments to be made to customers based on the wholesale price behaviour.'*[36] MDAG explicitly favoured this type of targeted scheme to address security of supply, rather than a broader 'negawatt'[37] scheme.

7.22. MDAG recommended against implementing an initiative where industrial consumers are paid regularly to reduce demand. It argued that these schemes:

(a) could result in significant regulatory cost, complexity and risk to integrate with New Zealand's electricity market

(b) create risks associated with inefficient deployment of demand side flexibility, (ie, they may over-incentivise, beyond an efficient level)

(c) would provide all the benefit of a contract for difference arrangement to an industrial, but not the downside – industrials wouldn't have to pay when the spot price was low

(d) can be distortionary, complex and difficult to remove in future.[38]

7.23. Overall, MDAG considered that there were other, lower cost, mechanisms to encourage the development and update of market-based demand response that should be pursued first.

7.24. We commissioned RBP to investigate international mechanisms for demand response, to ensure that we started with a broad perspective on potential mechanisms. RBP analysed centrally administered mechanisms for demand response in other markets including Australia's National Electricity Market, Texas, Pennsylvania, New Jersey, Maryland (PJM), California, Alberta and Singapore, as well as a proposal from the New Zealand CEO Forum, and considered implications for such arrangements in New Zealand.

7.25. RBP's findings broadly echo MDAG's concerns. Their review of international schemes developed to incentivise demand response found that:

(a) potential market distortions are likely to increase as participation by demand response increases

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[35] Broadly speaking, negawatt schemes treat a megawatt of demand reduction as equivalent to a megawatt of extra generation. This is true from a physical market-balancing perspective, but they are not equivalent from an economic perspective. Generators use resources and incur costs to produce a megawatt. Consumers save their resources for another use when they do not use a megawatt. The other key flaw is the difficulty in having an objective, verifiable measure of demand response, that is how much a consumer would have consumed in absence of the payment.

[36] MDAG, *Price Discovery in a Renewables-Based Electricity System: Final Recommendations Paper*, 2023, p114.

[37] Generally, a scheme where payments based on the wholesale price (aligned with what generators would be paid for wholesale generation) are paid to qualifying consumers who reduce consumption.

[38] MDAG, *Price Discovery in a Renewables-Based Electricity System: Final Recommendations Paper*, 2023, p75-76.

(b) there has been limited participation in these types of schemes in many jurisdictions. PJM is probably the most successful, and the scheme only represents about 2% of peak load – equating to around 140MW in the New Zealand context.

7.26. There are different views about whether negawatt schemes are truly distortionary, (ie, inefficient). For example, if consumers still pay a lower price (including the payment to the industrial) than in the counterfactual without industrial demand response, that remains to the benefit of consumers. We acknowledge different perspectives on the distortionary nature of paid demand response schemes.

7.27. We also consider that mechanism design strongly influences the level of impact on the market. For example, in a last-resort scheme as an ancillary service, a provider is paid on the same basis as other suppliers that provide the same service. This provides a level playing field, where potential payments are limited by the size of the ancillary service requirement. This is likely to be a less distortionary, lower risk and more targeted option than a negawatt scheme.

Immediate action 2: Develop standardised demand flexibility hedging product

7.28. MDAG recommended the development of standardised flexibility products to improve price discovery for flexibility and support efficient operation of the electricity system, particularly as it transitions to greater levels of intermittent generation.[39] The Authority's risk management review similarly identified that the market for shaped hedge cover, a key flexibility product, was not very deep or liquid.

7.29. In response to MDAG's recommendations, the Authority established the industry Co-design Group to work with us to develop a flexibility product for the wholesale electricity market. The Group decided to develop a new standardised super-peak hedge contract, which started voluntary trading from January 2025.

7.30. The Co-design Group also identified a demand response product as a high priority for consideration. It recommended that the Authority consider creating '*appropriate industry led workstreams to consider bringing new demand response products into the market, which could better unlock the potential of flexible industrial plant*.'[40]

7.31. The Authority supports the Co-design Group's recommendation. A standardised product for industrial demand flexibility could facilitate trading by better connecting potential flexibility buyers with sellers and by reducing transaction costs through standardised terms and conditions. This will be particularly beneficial for smaller retailers and will support prudent and efficient risk management.

7.32. We consider that development of a standardised product is also likely to foster innovation and increase the pool of potential demand flexibility available over time.

7.33. The Authority proposes to take a similar approach to developing a standardised industrial demand flexibility product to that of the super-peak flexibility product. This would entail an industry-led co-design group developing the product with support from the Authority.

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[39] MDAG, *Price Discovery in a Renewables-Based Electricity System: Final Recommendations Paper*, 2023, recommendation 8, p87.

[40] The Standardised Flexibility Product Co-design Group recommendations are available here: Standardised_Flexibility_Product_Co-design_Group_recommendation_to_EA_-_December_2024.pdf.

7.34. Our intention at this stage would be to have this product in place ahead of winter 2026, if it goes ahead. This is dependent on the exact nature of the product, and on any code changes that may be required to enable it.

Short- to medium-term actions: Foundations for future industrial demand flexibility

7.35. Except for the two actions outlined above, our current view is that more evidence is required before we should decide to establish additional market mechanisms or platforms, significantly increase regulatory incentives, or make further incremental modifications to existing market arrangements for industrial demand flexibility.

7.36. Given that the current scale of potential industrial demand flexibility appears limited, we would want to further assess the net benefits of additional mechanisms before proceeding with early design and testing with stakeholders. Other initiatives are also underway which will help identify how to overcome some of the barriers to industrial demand flexibility discussed above:

(a) Various pilots and trials are underway that may inform changes to existing mechanisms, and possible future markets and platforms, including projects supported by the Authority's Power Innovation Pathway and Ara Ake.[41]

(b) As part the 2025 reset of the default price-quality path for regulated networks, the Commerce Commission has approved an innovation and non-traditional solutions allowance (INTSA) for EDBs.[42]

7.37. While these activities progress, the need and potential for flexibility services is growing. It is important that the learnings from existing mechanisms, pilots and trials are captured and used by the sector to transition from this current 'learning' phase, to one where demand flexibility is a mature and embedded provider of flexibility services in the market and to networks.

7.38. The Authority's view is that substantial progress should be made over the next two to three years to enable this transition. Our roadmap sets out several further actions we propose to take from 2025 to 2028 to lay the foundations for the future provision of flexibility services to the market. These actions are likely to be relevant for demand response from industrials and other consumers.

7.39. These proposed actions include:

- **Action 3: Developing a new clause 2.16 notice for demand response** contracted by EDBs and Transpower. This, in conjunction with information collected under existing requirements, will provide the Authority with a comprehensive picture of the use of type 2 demand response under bilateral contracts.

- **Action 4: Leveraging the EECA-EEA flexibility scan**, develop and publish guidance to assist further pilots and trials to prioritise remaining knowledge gaps, avoid duplication and move to embed flexibility services in 'business as usual' operations.

[41] Information about flexibility projects supported by Ara Ake, including Transpower's Flex Visibility Project, is available at https://www.araake.co.nz/projects

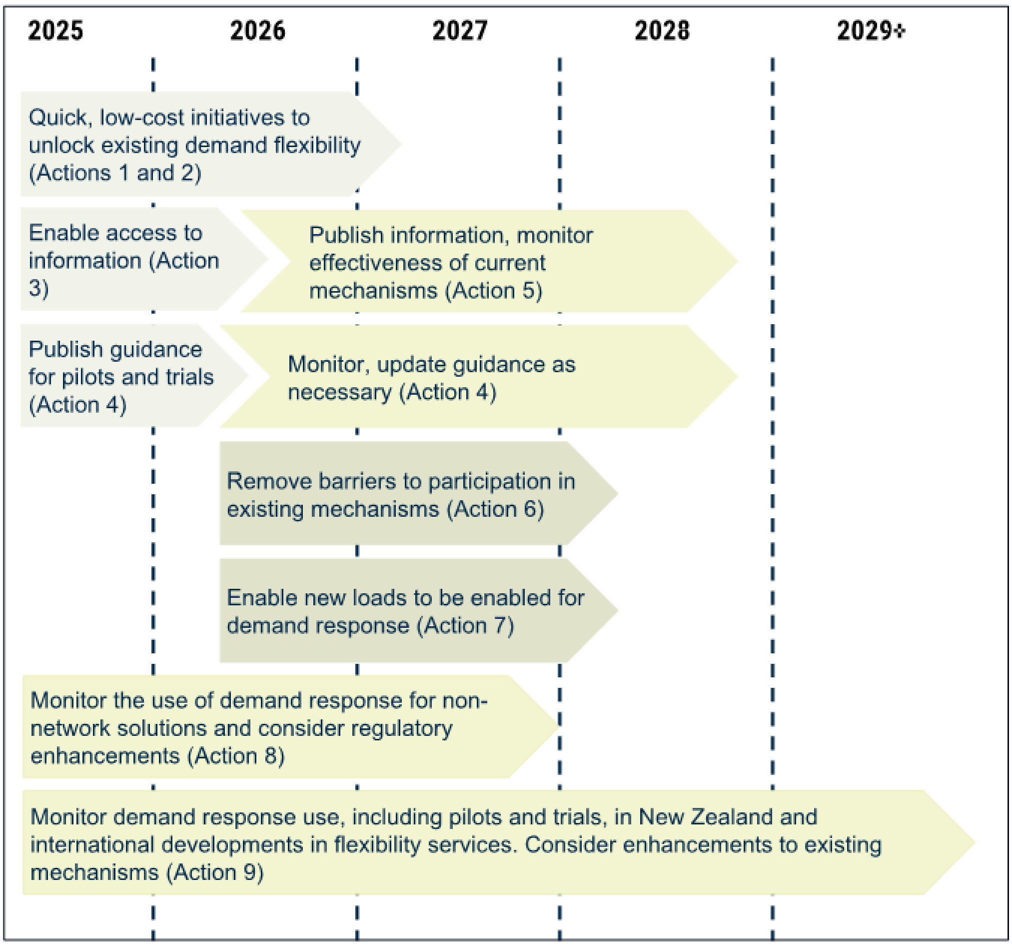
[42] More information is available on the Commerce Commission website at https://comcom.govt.nz/regulated-industries/electricity-lines/projects/2025-reset-of-the-electricity-default-price-quality-path

- **Action 5: Publishing information** collected under clause 2.16 notices, hedge disclosure requirements and network business asset management plans to provide transparency to the market on the use of demand response.
- **Action 6**: **Exploring Code or other changes to enable third-party providers** to participate in the provision of industrial demand flexibility across all market and contractual mechanisms (including hedging).
- **Action 7**: **Exploring Code or other changes to enable new or upgraded connections** to be 'demand flexibility ready'.
- **Action 8: Monitoring the use of demand flexibility for non-network solutions** and evaluating if there is a need for enhanced regulatory requirements.
- **Action 9: Monitoring the use of demand flexibility, including in pilots and trials** in New Zealand, and international developments in flexibility services, to identify and consider opportunities (if any) to enhance existing mechanisms.

7.40. We note that many of these proposed actions align with other Task Force and Authority work programmes. For example, the Authority's distributor involvement in flexibility services markets workstream is working to support a competitive flexibility services market for more efficient and cost-effective use of the distribution network.

7.41. The following Figure 5 summarises the proposed short-to medium- term actions. (A summary of all roadmap actions is provided in Appendix A).

Figure 5: Roadmap actions and indicative timing – short- to medium-term actions



Longer-term actions

7.42. As the need for flexibility services and industrial demand flexibility potential grows over time, it is likely that further new or modified market mechanisms will be identified to more effectively realise our proposed vision. The Authority's work programme will need to be responsive to these changes over time.

7.43. The proposed near-term actions outlined above are intended to lay the foundations for a future. We think that they will do this by:

(a) enabling greater use of industrial demand flexibility when it offers the most value to the system

(b) encouraging innovation to enable flexibility services

(c) reducing barriers to the provision or purchase of demand flexibility via existing mechanisms

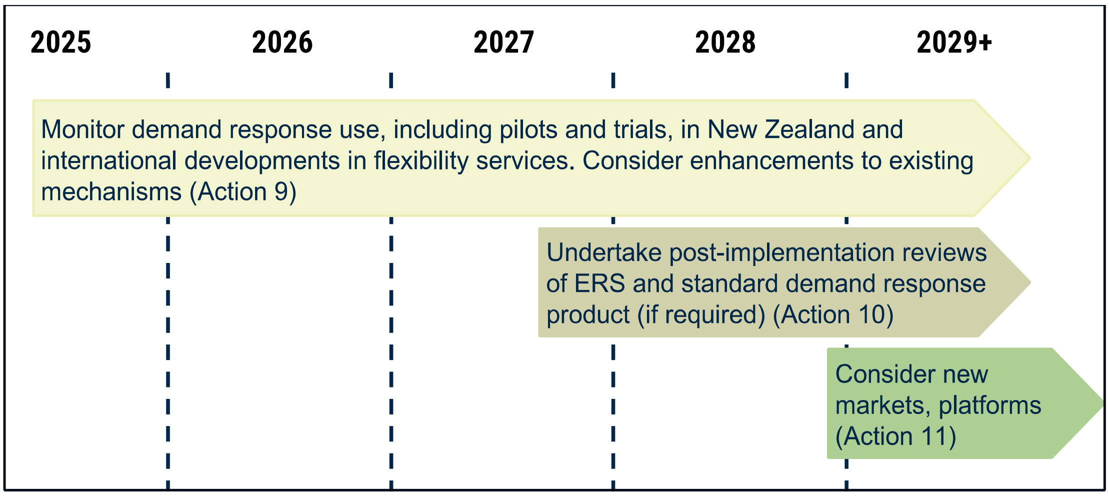
(d) providing information to evaluate the effectiveness of mechanisms for demand flexibility to enable assessment of future options.

7.44. We propose to undertake two longer-term actions from 2028 onwards to evaluate the need and effectiveness of demand flexibility mechanisms. Action 9 will also play a supporting role for these two actions.

- **Action 10: Undertake post-implementation reviews** of the ERS and standardised demand flexibility product (subject to the implementation of these two actions).
- **Action 11: Consider options for flexibility services from demand in the future**, including whether new market mechanisms or platforms should be developed to enable greater levels of efficient demand flexibility.

7.45. Figure 6 (below) summarises these actions and their indicative timing, noting that the detailed design and implementation of any future new or amended mechanisms are to be determined, including in response to further feedback. The scope and timing of initiatives will also need to be revisited periodically in response to the changing needs and conditions of the electricity sector.

Figure 6 Roadmap actions and indicative timing – longer-term actions



8. Next steps

8.1. The Authority welcomes your feedback on this consultation paper by 26 June 2025. Your views will help inform our roadmap and the actions we take over the next five years to enable intra-day industrial demand flexibility services. We propose to publish a final roadmap in August 2025.

8.2. We are intending to launch a separate consultation on an ERS in July 2025 for feedback on potential design options. This timing is necessary to enable an ERS, if ultimately supported and implemented, to be in place for winter 2026. Our preliminary view is that an ERS is well aligned with our vision, and that it would reward willing demand-side market participants for making their resources available during periods of very high electricity demand and insufficient supply. It will also support the sector to build demand flexibility capability.

8.3. The Authority also proposes to establish an industry Co-design group to develop the standardised industrial demand flexibility product, in line with the approach taken for the development of the standardised super-peak hedge contract, which started trading from January 2025.

Appendix A Proposed roadmap of actions to enable future intra-day flexibility from demand response

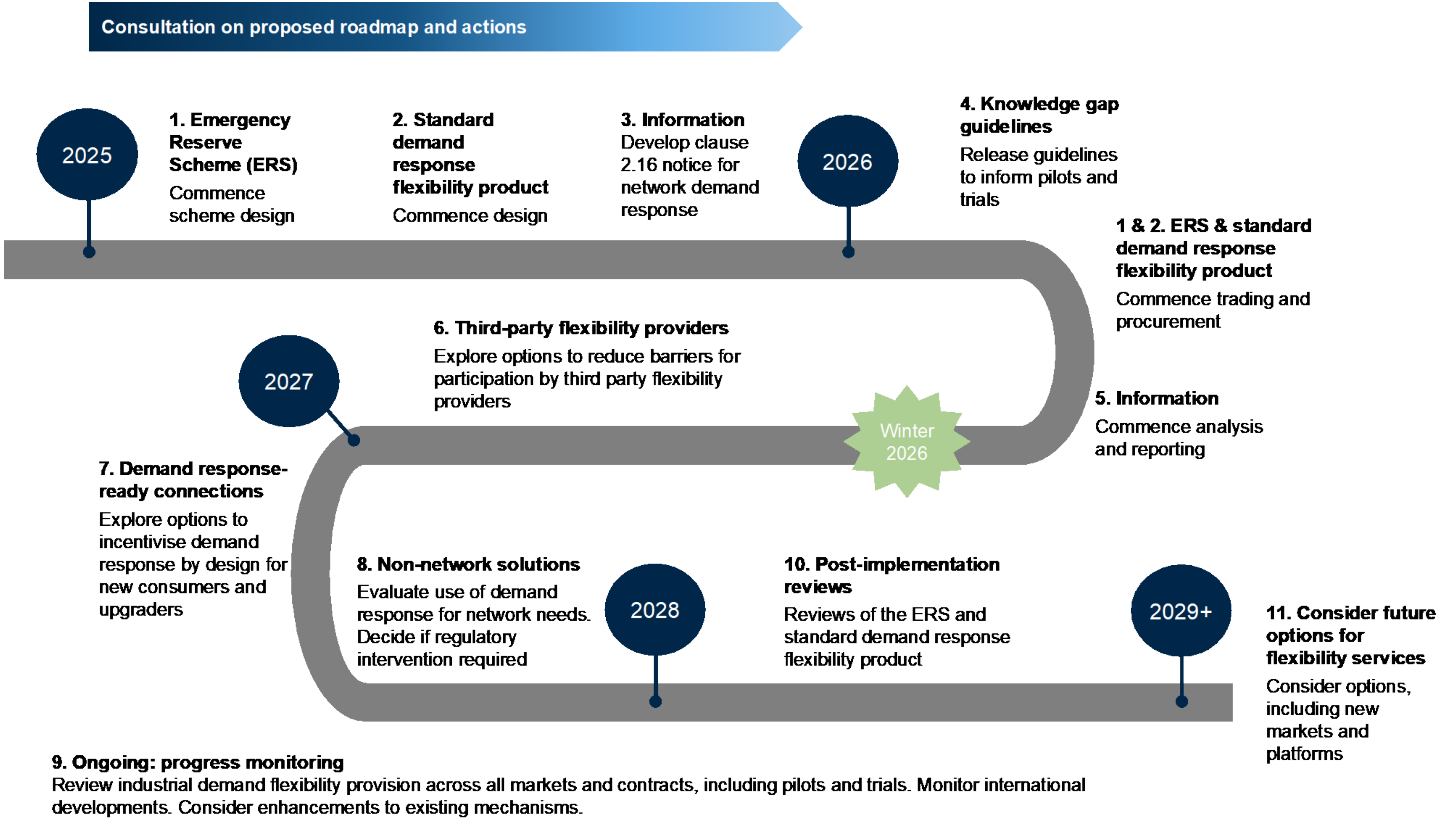
Action	Proposed Timing	Rational for action
Action 1: Consider potential options for an Emergency Reserve Scheme	Winter 2026 (subject to consultation and further decision making)	Greater generation intermittency is creating challenges for security of supply, especially during cold, still mornings and evenings. Transpower's outlook for the 2025 winter indicates that peak capacity risks, especially during cold snaps, will persist until there is sufficient investment in flexible resources such as batteries, demand response and peaking generation. This issue is not likely to resolve quickly, with potential winter peak capacity shortfalls also identified from 2027 onwards. There are opportunities for industrial consumers to support the system during these types of events, including by lowering consumption at times of peak demand and low residual generation, freeing up more supply and reducing the likelihood of involuntary load shedding. Sense Partners' analysis indicates that this may offer a more efficient solution compared to the cost of investing in additional supply for brief and infrequent use.
Action 2: Develop a standardised demand flexibility hedging product	Winter 2026 (subject to consultation and further decision making)	Both MDAG and the Authority's risk management review identified a need for more hedging options to support the transition to more variable renewable generation. The Co-design Group, which was established develop a new standardised super-peak hedge contract, also recommended that the Authority consider bringing new demand flexibility products into the market. A standardised flexibility product for demand response will improve access to flexibility for all potential buyers, especially smaller retailers, supporting prudent and efficient risk management. The recently developed super-peak product indicates industry capability to develop new over-the-counter standard products quickly.
Action 3: Develop a new clause 2.16 notice for demand response contracted by EDBs	As soon as possible	The Authority requires information to assess the effectiveness of existing bilateral contracting mechanisms for flexibility services. Recent 2.16 notices, hedge disclosure requirements and enhancements to network asset management plans will provide much of this transparency, however the Authority is not aware of a current requirement to ensure contracts between networks and demand flexibility providers are shared with the Authority.

Action	Proposed Timing	Rational for action
and Transpower for consultation		Any clause 2.16 notice and applicable timeframes for providing information would be developed in consultation with stakeholders.
Action 4: Develop and publish guidance for pilots and trials. Monitor and update guidance as necessary.	2026	Many pilots and trials have been undertaken which are relevant to enabling demand flexibility. It is important that further trials are targeted to remaining knowledge gaps in order to progress to enduring solutions, where appropriate. The volume of pilots and trials undertaken and underway, and complexity of issues considered, can present significant challenges in determining whether sufficient information is available to move away from trials and embed new arrangements into ongoing market or business practices. Summary information from the EEA-EECA scan shows customer engagement to be an area that has had little focus to date from pilots and trials. Anecdotal information from other stakeholders indicates that commercialisation has not had adequate focus. Leveraging the EEA-EECA, the Authority proposes to develop guidance to assist further pilots and trials, including as part of the Authority's Power Innovation Pathway programme, to prioritise remaining knowledge gaps, avoid duplication and move to embedding flexibility services in 'business as usual' operations.
Action 5: Publish information about the use of demand response	Commencing early 2026	Publish information collected under clause 2.16 notices, hedge disclosure requirements and network business asset management plans to provide transparency to the market on the use of demand flexibility. Information could be aggregated where required to address confidentiality concerns.
Action 6: Explore Code or other changes to enable third-party providers to participate in the provision of flexibility services by industrial	2026	Enabling third-party providers (for example, through multi-trader relationships, or through another mechanism) to participate in the provision of flexibility services is expected to provide benefits for consumers by: • enabling more choice for consumers in the management of their energy use and costs • increasing the scale of services likely to be offered, improving liquidity in the market • increasing competition in the provision of flexibility services, helping to overcome some of the barriers faced by the existing practices and processes of incumbents, and incentives faced by gentailers • supporting 'value-stacking' across compatible uses of demand flexibility.

Action	Proposed Timing	Rational for action
demand flexibility across all market and contractual mechanisms (including hedging)		The Authority proposes to engage with stakeholders as it explores options to more effectively enable participation by third-party flexibility providers.
Action 7: Explore Code or other changes to enable new or upgraded connections to be 'demand response ready'	2026 – 2027	Electricity demand growth will occur because of the connection of new consumers' loads and upgrades to existing loads, including to enable electrification of plant and equipment. The best time to ensure this plant and equipment is enabled for demand response is likely to be at the time it is being connected or a connection upgraded. Electricity networks and wholesale market participants such as retailers have key roles to play in ensuring consumers are aware of incentives to provide flexibility. The Authority proposes to engage with stakeholders on options to promote 'demand response ready' loads as part of the consumers' new or expanded connections and preparations for purchasing energy services.
Action 8: Monitor the use of demand response for non-network solutions and evaluate need for enhanced regulatory requirements	Late 2027	Several electricity networks have trialled demand flexibility as a form of non-network solution over many years. Despite equivalent regulatory incentives for operational expenditure for non-network solutions and capital expenditure for traditional network solutions, the use of non-network solutions has not matured to the extent the Authority would expect. The Commerce Commission will commence the process for the next price-quantity paths for regulated EDBs and Transpower in early 2028. Prior to this, progress in the use of non-network solutions, including the use of the INTSA, should be evaluated. If the use of non-network solutions has not matured sufficiently over this period, the Authority proposes to consider further regulatory measures to enable greater uptake. Consideration of options would be undertaken in consultation with the Commerce Commission, regulated networks, and other stakeholders. This would be aligned with other ongoing work on distributor involvement in flexibility markets.
Action 9: Monitor the use of demand response, including in pilots and trials,	Ongoing	The information collected and published on the use of demand flexibility will enable ongoing monitoring of existing mechanisms, including bilateral contracting, hedging, and market mechanisms.

Action	Proposed Timing	Rational for action
in New Zealand and internationally, and explore opportunities to enhance existing mechanisms		Internationally, flexibility markets and platforms are being trialled and implemented in many liberalised electricity markets. These should also be monitored to identify best practice and consider learnings and their application (if any) in New Zealand. This would include mechanisms in other energy-only electricity markets (eg, Australia's National Electricity Market, Singapore), as well as relevant examples in markets with different structures (eg, United Kingdom, Europe, North America). Where this information identifies an opportunity to enhance existing mechanisms, the Authority will explore and implement relevant enhancements in consultation with stakeholders.
Action 10: Undertake post-implementation reviews of Emergency Reserve Scheme and standardised demand flexibility product (if implemented)	2028	Consistent with good practice, post-implementation reviews should be undertaken of new initiatives to confirm if expected outcomes were realised and consider whether to continue or evolve these mechanisms. This will form part of a broader assessment of the effectiveness of mechanisms to enable and reward industrials for providing flexibility services.
Action 11: Consider options for flexibility services from demand response in the future, including new markets or platforms	2029+	Drawing on the insights from existing mechanisms, post-implementation reviews, pilots and trials and international experience, the Authority proposes to consider options for future markets, platforms or other mechanisms to achieve the proposed vision for industrial demand flexibility over the longer-term. This could include Authority support for development of a market platform to facilitate price discovery of demand flexibility products. This will also have regard to updates in future electricity demand and supply forecasts. Options and implementation (if required) will be considered in consultation with stakeholders.

Appendix B Proposed industrial demand flexibility roadmap



Appendix C Industrial demand flexibility: Sizing the potential of useful demand response

Industrial demand flexibility

Sizing the potential of useful demand response

March 2025

SENSE PARTNERS
DATA LOGIC ACTION

Executive Summary

This report sets out high level estimates of industrial demand response and its cost

This report sets out a framework for classifying and thinking about different forms of demand response (DR) and provides high-level estimates of the potential availability and costs of industrial DR.

The focus is on the extent that industrial consumers of electricity may be willing to use less electricity when it is scarce and expensive, such as at peak demand times or when supply is relatively low because of fuel shortages.

The focus on industrial electricity demand flexibility reflects that industrial consumers account for a relatively large share of electricity consumed (32%) yet are relatively few in number (2% of ICPs). See Table 1.[1] According to the Authority's recent survey data, large- and small-scale commercial and industrial consumers account for over half of the potential DR.

This suggests that in principle industrial consumers offer potential for targeted interventions to unlock additional DR that, on the whole, could benefit consumers by promoting more efficient operation of the electricity industry. The questions remaining are how much additional DR can be unlocked and what interventions would help do so in a way that would be for the long-term benefit of consumers?

TABLE 1: ELECTRICITY CUSTOMERS AND ANNUAL CONSUMPTION BY SECTOR MARCH 2024[2]

Sector	# of ICPs	GWh	Expenditure $m	Share of ICPs	Share of GWh
Primary	86,000	2,700	600	4%	7%
Industrial	47,000	12,900	2,200	2%	32%
Commercial	192,000	9,500	2,000	9%	24%
Residential	1,853,000	13,800	4,600	85%	35%
Transport	4,600	300	100	<1%	1%
Unallocated	7,800	700	200	<1%	2%
Total	2,177,000	40,000	9,500		

The high-level results set out in this report are the result of a top-down desk-top analysis based on limited data and undertaken over a brief period of time. The report sets out the main limitations of the data used and findings, though the results should assist the Authority

1 Sense Partners estimates using MBIE data.
2 Totals and column sums may not align due to rounding.

to understand whether and where it could focus its attention to unlock any additional DR as part of the Energy Competition Taskforce's work.

Industrial DR potential is limited by commercial considerations

Overall, we find that the potential for industrial DR:

- is substantially smaller than technological assessments suggest, due to costs of engaging in DR and higher returns to effort for actions outside of managing electricity costs
- is up to 6% of typical daily peak demand and 2% of typical winter peak demand if relied upon at short notice
- can be expensive, with substantial incentives required to procure more than small amounts of DR and significant income losses, in the range of $1,000 to $5,000 per MWh, if load reductions are sustained.

Estimates of technical DR potential are large

A recent technical assessment of DR potential in New Zealand finds that the potential is very large and should be available subject to retrofitting controllers and price incentives.

However *technical* potential is not the same as *economic* potential – DR that would be offered if incentives are right, the pay-off meaningful, and there is a reasonably low-cost way to trade DR with a counterparty or via some trading platform.

Results from interviews with Australian industry and market experts in 2013 indicate DR of around 20-40% of industrial demand at peak (or 5-10% of total load at peak) would be commercially viable for relatively short interruptions 5-10 times a year.

There are various limiting factors to consider

Those Australian results relied on very high incentive levels – the higher estimate reflecting the cost of additional network and generation capacity to meet an additional MW of peak demand, and the lower estimate being around half that amount. Consumers may not be better off if DR is procured at the same price as incremental system capacity costs.

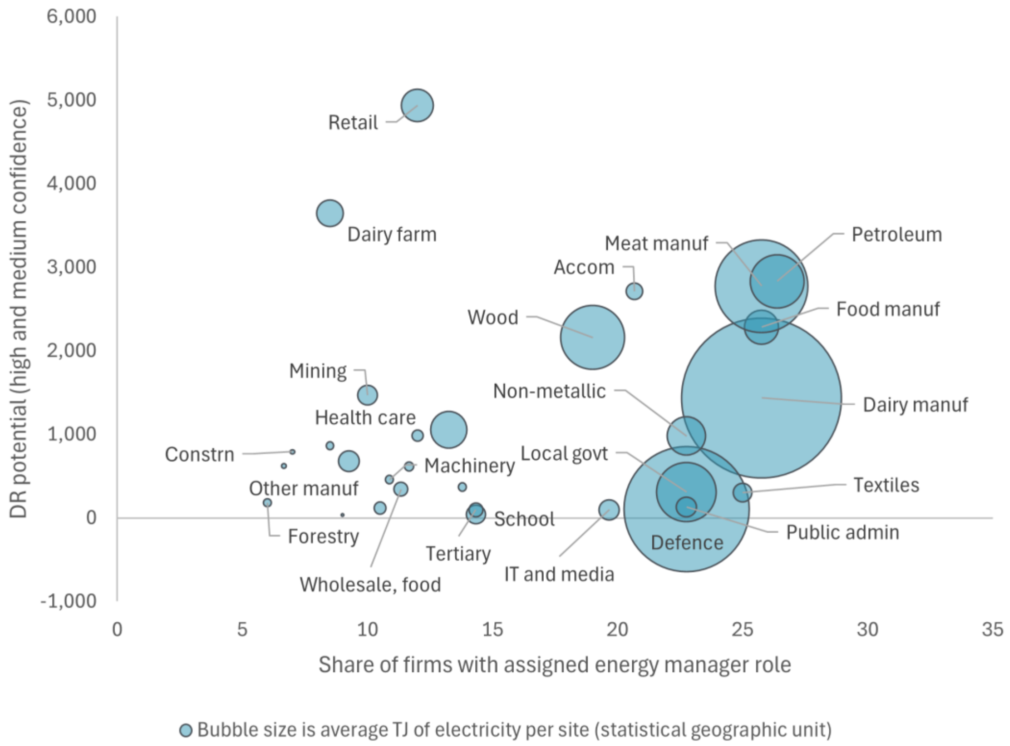
Also, at a firm level electricity is (with some exceptions) not an important input cost. In New Zealand median electricity cost is only 1.3% of total input costs (excluding labour and capital cost). In other words, most firms in most industries do not have strong incentives to invest in closely managing electricity costs.

Stats NZ surveys indicate only 11% of firms have a dedicated budget for energy management, and the presence of energy management capability is more likely the greater the energy use or intensity per site. Conversely, the more dispersed an industry's energy use is over multiple sites, the higher the transaction costs relative to potential benefit to firms from offering DR.

These (imperfect) indicators point to organisational capacity and potential incentives to engage in DR being concentrated in a handful of manufacturing industries with large plants e.g. primary metals, forest products, and dairy processing (see e.g. Figure 1)

FIGURE 1: INDICATOR OF DEMAND RESPONSE CAPABILITY VS POTENTIAL

Industries in Williams and Bishop 2024, pulp and paper and primary metals industries removed as outlying exceptions. DR potential is the sum of high and medium confidence DR potential in Williams and Bishop.



Seasonality of industrial demand also limits the potential for DR mid-winter. Primary sector activity tends to be low in winter, and electricity demand for milk production, meat production and irrigation declines significantly mid-winter. We estimate that winter *industrial* intraday peak demand is 15% lower than the rest of the year.

Strong incentives may deliver higher rates of demand response

Our analysis indicates that the scale of potential industrial DR ranges from 190 MW to 300 MW, accounting for technical feasibility and organisational capabilities of industries. This is a conservative estimate, restricted to industries where we have high confidence in DR potential. However, it is roughly in line with what was observed by the Authority in its 2024 survey of DR potential (250 MW).

The Australian survey indicates that, even with very high incentive levels, only one-half to two-thirds of that DR potential would participate in DR programmes in practice.

The Australian study does, however, indicate that sizeable incentive payments could induce DR from unexpected sources (industries and processes).

Our analysis shows that the high end of such incentives, in the New Zealand context, is around $250,000-$300,000 per MW. This is roughly in line with estimates of the incremental cost of 1

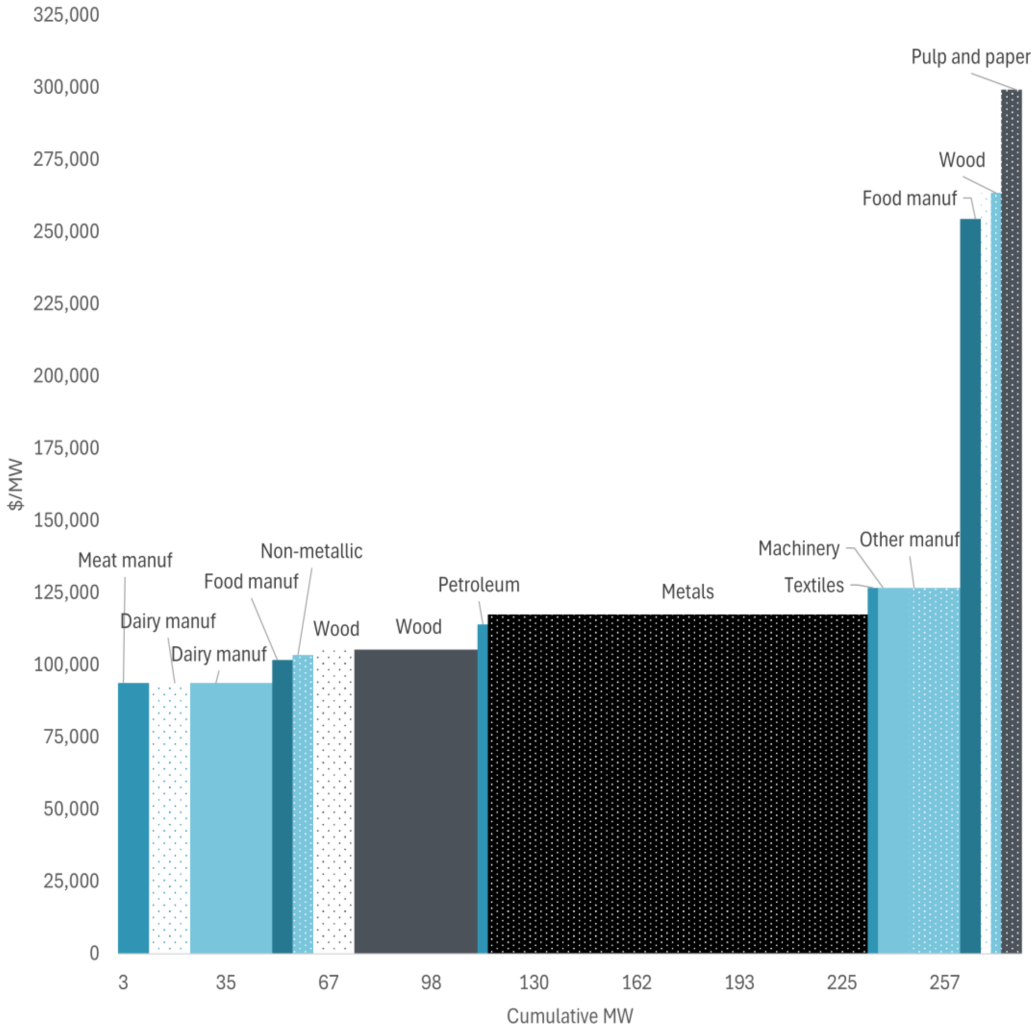
MW of peak demand, though incentives needed to induce DR could in principle be much lower (see Figure 2).

Our estimates do not represent the cost required to induce DR nor the value of DR. Instead, they are a very high-level estimate of how much DR might be achievable for a given level of incentive.

Whether such incentives (costs) would be justified depends on the details and those are beyond the scope of this piece of work. A better appreciation of the costs and benefits of incentives for DR requires in-depth analysis of concrete options for implementing them.

FIGURE 2: INDUSTRIAL DEMAND RESPONSE CONDITIONAL ON INCENTIVE PAYMENTS

DR potential shown here is for Intraday Peak MW (not Winter Intraday Peak). Block patterns indicate confidence levels assessed in Williams and Bishop: solid blocks are high confidence, patterned blocks with solid backgrounds are medium confidence, and blocks with white backgrounds and dots are low confidence.



Sustained demand response is costly

Our estimates concern infrequent DR available for reasonably short duration to balance intra-day demand. In dry years in particular there may be demand for more sustained DR. This is possible, but implies substantial shedding of production, which is costly.

The shadow cost of DR includes the potential loss of value added (capital and labour income). This is a multiple of electricity costs. By way of illustration, this report presents measures of income loss from reduced production by sector. These are typically in the range of $1,000 to $5,000 per MWh, for those industries and processes considered most capable of providing DR.

Those are of course only high-level estimates. More accurate estimates of the shadow cost of DR (and potential gains from trade) will require in-depth market analysis using detailed data on the actual operations or real participants.

Similarly, we have not analysed the potential for permanent changes in load profiles in some industries. That too would carry a shadow cost – to implement such a change.

We consider structural changes in industry operation to be distinct from typically shorter-lived DR measures.

SENSE PARTNERS
UNCOMMON KNOWLEDGE

1. Purpose

1.1. Demand side flexibility

This report presents:

- a framework for classifying and thinking about different forms of DR
- high-level estimates of the potential availability and costs of different forms of DR, with a particular focus on industrial DR.

Such estimates (subject to data limitations) reveal a supply curve of DR, that ranks potential DR capacities by their cost, taking account of key characteristics such as notice periods and the duration and frequency of availability.[3]

These estimates help the Electricity Authority to better understand whether and where it could focus its attention to unlock any additional DR, specifically with respect to industrial DR to support the Energy Competition Taskforce.

1.2. Focus on industrial consumers' flexibility

Demand side flexibility (or the capacity to provide DR) is useful alongside intermittent generation and has other potential benefits that explain the focus on improving its integration into in the electricity market.

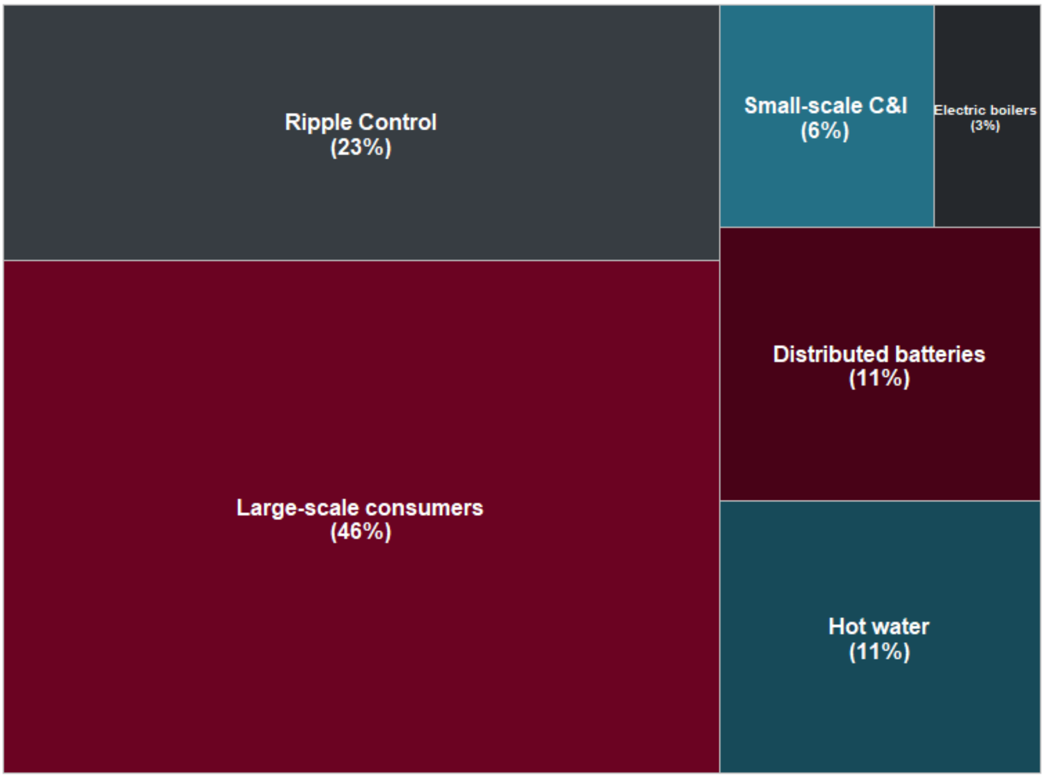
Responses to a recent survey conducted by the Authority (2024) found that large scale consumers account for around 46% of 450MW demand side flexibility that is in theory available. As the Authority noted, these responses do not capture all the demand side flexibility, and its availability at any point in time will vary. See Figure 3.

A particular interest for the Authority is to what extent industrial consumers of electricity can use less electricity when it is scarce and expensive, such as at peak demand times or in case of relatively low supply because of fuel shortages. [4]

[3] A consumer may be able and willing to offer 'tranches' of DR in different markets (e.g. network, wholesale, ancillary services) and durations (e.g. short interruptions of heating/cooling vs rescheduling or shutting down production for hours or days), at different prices.

[4] See workstream 2D of the Energy Competition Taskforce at https://www.ea.govt.nz/projects/all/energy-competition-task-force/ .

FIGURE 3: 450MW OF POTENTIAL DEMAND SIDE FLEXIBILITY BY SOURCE



Source: Electricity Authority 2024

2. Framing

This section sets out a framework for classifying and estimating different forms or applications of demand response (DR).

It discusses what is DR for the purposes of this report, when DR is beneficial and when it is not. It then sets out an approach to classify DR, estimate the potential DR, and to value DR.

This draws on existing publications and data to sketch an 'offer curve' of DR that is economically viable under plausible market conditions.

2.1. Two generic types of demand response

Consumers act on information in line with their incentives

Our starting point is that consumers[5] will only pay for electricity to the extent that they benefit from its use, and that producers will only supply electricity to the extent that prices at least cover marginal costs (and over time are expected to recover the full costs).

Further, the wholesale electricity market supports the process of discovering efficient quantities and prices for electricity – with the market process of matching offers to demand revealing how much, 'on the margin', consumers value electricity and the least cost to supply them – at specific times and locations.

This is the setting for DR[6], of which there are, broadly speaking, two types:

- **Type 1**: consumers reducing how much electricity they choose to buy in response to an increase in electricity prices (including time-of-use tariffs). This is sometimes referred to as an 'implicit' DR. The size of DR will be uncertain as it will depend on how much each consumer would otherwise have consumed, which may not be able to be observed at reasonable cost.
- **Type 2:** consumers reducing their use of electricity by a defined quantity in return for an agreed payment. This is sometimes referred to as an 'explicit' DR. DR may be in response to an instruction from a supplier or system operator, or a decision by consumers to on-sell electricity they had previously purchased for their own use.

[5] As per the Electricity Industry Act, consumer means 'any person who is supplied, or applies to be supplied, with electricity other than for resupply'.

[6] We follow MDAG's approach (Batstone 2022) by putting aside energy efficiency investments and fuel switching choices that shape load profiles in the longer run, or discussion of the use of flexible demand for network management purposes such as to manage occasional network congestion, or as an alternative to investment in a network.

Type 1: Consumers respond to market prices

In stark terms, consumers with variable volume contracts reduce their demand for electricity when market prices rise above the value to them of using that electricity at that time.

End consumers then forego benefits they get from heating, lighting and appliances. Commercial and industrial consumers may also forego profits from any reduced production. Or they may buy and use electricity at another time at a lower unit price (or use other energy sources that are cheaper at the time).

The foregone benefits or profits can be taken to be less than the cost of electricity they saved, otherwise consumers would be unlikely to have reduced their electricity use.

Consumers would not be paid for this DR. They benefit by saving money to use for something they value more.

Larger consumers can participate directly in the wholesale market by bidding in DR quantities at specific spot prices.[7] This is one way for those consumers to manage price risk, with the protection of constrained-on and -off payments.[8]

In practice the DR process is likely somewhat less deliberate, calculative, and instantaneous than may be portrayed:

- consumers cannot watch prices constantly without dedicated resources to participate in real time
- production processes may lack the flexibility to turn off and on in the timeframes of wholesale market dispatch[9]
- consumers may not be willing to risk the issues (damage to plant, output and supply chain interruptions) that can arise when complex production processes are interrupted.

Changing habits or production processes to be able to create demand-side flexibility takes time and effort. Further, consumers' budget constraints rather than a reassessment of relative value may drive economising behaviour.

Retail time-of-use tariffs and the like provide incentives to form demand patterns that shift some use to off-peak times (e.g. automated, set-and-forget responses). But time-of-use tariffs reflect market conditions and prices on average. They are not a perfect signal to guide and incentivise DR at a specific point in time.

7 Aggregators can provide this as a service to mass market consumers.

8 These pay the difference between bid and final spot price, when consumers provide a DR on an expectation of high prices but the final price is low, or when consumers do not reduce load on an expectation that prices will not be high, but the final price is high.

9 In 2024 the Authority identified options to enhance dispatchable demand for further development, including providing for the ability for dispatchable demand participants to signal how long an industrial process must remain off before they can be restarted, and ramp-down and -up rates.

Because of these factors, Type 1 DR may be slow to evolve.

Most consumers are not directly exposed to spot prices but pay a set retail price per unit of electricity or have some other protection against price volatility (e.g. fixed price contracts with generators, financial hedges, or their own generation).

Consumers may prefer fixed prices if they have limited ability to change demand materially, at least in the short term, or if the transactions cost of engaging with the market are too high relative to the expected benefits to them.

While it is true that many consumers are hedged against price risk, this just means someone else (e.g. a retailer or others) will be exposed to wholesale market prices. The exposed parties have an incentive to find and induce consumers to reduce demand when wholesale market prices are higher than the fixed price tariffs (whether a basic flat rate or time-of-use).[10]

In its 2024 Decision Paper on *Potential solutions for peak electricity capacity issues*, the Electricity Authority lists at paragraph 3.58 contemporary examples of retailers and others rewarding customers to reduce consumption during peak demand times (such as Octopus Energy's savings sessions, or Simply Energy's retail energy services).[11]

The size of a Type 1 response is uncertain. It depends on how much consumers would otherwise have consumed.

For the mass market (residential and small business customers) this 'baseline' cannot usually be observed, or at least not at reasonable cost given the volume of customers. This is because it depends on their specific preferences and circumstances, which only they can know.

The information problems about the availability and actual size of DR increase the transaction costs of trading this type of DR and decrease its value. This can be addressed to some extent by technologies that give retailers/aggregators control over load (e.g. hot water, EVs, appliances, batteries). Retailers/aggregators can also manage quantity risk by averaging over large numbers and offering prices that reflect such risks.

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10 The incentive would likely be a share of the difference between the spot price and the customer's tariff.

11 See https://octopusenergy.nz/saving-sessions and https://simplyenergy.co.nz/demand-flexibility/, referenced on pp 29-30 of: https://www.ea.govt.nz/documents/5263/Decision_paper_Potential_solutions_for_peak_electricity_capacity_issues.pdf

Type 2: Contracts for deliberate and controllable demand response

Type 2 DR involves consumers who have purchased electricity to:

- make available defined volumes as interruptible load (e.g. instantaneous reserves)
- sell back defined volumes to their supplier or into the wholesale market when market prices exceed the marginal value to them of using electricity
- reduce load by a defined amount on the supplier's request, for example, under specific conditions set out in a supply contract.

Instantaneous reserves

Consumers can make defined volumes of load available to be interrupted at short notice, for example as instantaneous reserve in case of an unexpected, sudden outage that puts continued system supply at risk.

This can provide a revenue stream for load that has a low opportunity cost when disrupted for short periods of time (such as refrigeration, air conditioning, lighting, hot water heating, or charging a battery). Consumers need to have installed the correct equipment to make this possible as the DR needs to occur automatically in response to sudden changes in system frequency due to generation or transmission outages, and the system operator needs to be able to rely on the offered DR.

Over time, income from participation would need to at least cover the expected cost (including from foregone production) from any interruptions. In terms of instantaneous reserves, prices paid are usually low[12]. However the probability that load would be interrupted is also low, the duration of interruptions is relatively short, and providers can limit the interruptions to demand that is of relatively low value to them.

Selling- or buying-back rights to volumes

Consumers may also find that it is worthwhile to trade some volumes they had previously contracted to take at specific times and locations at some agreed purchase price.

This may be when electricity market conditions turn out to be materially different than was expected at the time of the contract, and greater scarcity of supply has driven up electricity prices.[13]

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12 https://www.ea.govt.nz/news/eye-on-electricity/keeping-the-lights-on-with-reserves/

13 Another use case outside the scope of this report is when contracted electricity volumes may turn out to be more than what the consumer requires for its production processes, for example, because orders or commodity prices are running below a producer's prior expectations.

When this occurs, both the consumer and the supplier of the electricity may now have incentives to depart from their prior agreement, if they can settle on a mutually beneficial price:[14]

- consumers may now wish to sell back (or on-sell to third parties) those volumes for which market prices now exceed the marginal value to them in use or in production
- retailers or generators may now want to buy back rights to volumes from their customer, so that suppliers can sell these on the spot market to take advantage of higher prices, or as a less costly way to cover any unhedged portion of the volumes they are contracted to supply.

These trades may occur on an ad-hoc basis, or the original purchase agreement may have provided for the option in detail, or at least a process and formulae to confirm the details.[15]

In essence, DR contracts are one way for parties to the contract to manage price risk over the term of the contract.

The presence of mutually beneficial trades does not mean they will be realised. The gains may not be sufficiently material or frequent for a firm to be prepared to interrupt its production processes, particularly if the firm has a fixed price contract or otherwise hedged its price risk in a way that involves fewer transaction costs and production issues.

Costs of providing demand response

Being DR capable and then providing DR creates costs that will inform consumers' willingness to provide DR at different price points.

Costs include:

- foregone production for business consumers. This means a loss of profit, with any loss of revenue partially offset by any variable production costs such as wages and materials that may be avoided in addition to electricity costs.
- foregone services for end-consumers, such as light, heating/cooling, appliance use. One way to assess this cost is to observe how demand changes in response to an increase in price (or variable tariff plus any incentive offered by an aggregator)
- costs of equipment and enabling technology to offer DR (both capital and operational expenses).

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14 The value of the option on electricity is the difference between the market price M and original contract price C (ignoring transaction costs, uncertainty, shut down and start-up costs, and assuming C reflects the consumer's marginal value from using electricity). The value of the option (M-C) will be shared between the buyer and the seller

15 A prominent example is the Meridian, Contact, and Mercury supply agreement with NZAS, which includes DR options of up to 185MW (covering different notice and ramping periods, durations, and limits on the times the options can be called.)

- costs of developing and learning new work processes and training personnel
- opportunity costs of keeping flexibility available
- risk premiums for uncertainty of being called upon
- transaction costs, including searching for and matching suitable counterparties, developing agreements, monitoring electricity market conditions and responding to price signals or instructions, confirming performance and payments, and managing disputes.

Features of contractable demand response

While both types of DR can be beneficial (in terms of promoting the Authority's statutory objective), and industrial consumers participate in both, the focus of this report is on Type 2 DR.

In essence this type of DR is a (potentially) tradeable option on a volume of electricity which the consumer could consume or sell back, where:

- DR is deliberate, controllable, and verifiable (at reasonable cost)
- quantities, prices and any other details of DR are determined through a process of mutually beneficial trades between willing buyers and sellers (bilaterally or through some market platform)
- the exercise of the option is voluntary (subject to any agreed pre-conditions).

Contracts for this type of DR observed in NZ are bespoke, bilateral and long-term agreements. These arrangements seek to manage risk of hold-up (where one of the parties can take advantage of the other), due to the following features (see Williamson 1979):

- asset specificity – significant investments in bespoke capability may need to be made required for commercial and industrial consumers to be ready to provide DR. This is an issue if these are relationship-specific investments that have little or no value outside the contract
- uncertainty – for example about when and for how long price conditions arise where a DR would be beneficial. This can make it very difficult to specify upfront what is needed, when and what good performance is, or very difficult to verify performance after the fact.

2.2. Potential system benefits from demand response

Demand side flexibility promotes competition, reliability and the efficient operation of the electricity market.

Allocating electricity to highest value uses

Demand flexibility supports the efficient operation of the market. Abstracting from real-world frictions as described above, it allows users to optimise their consumption to achieve the greatest benefit:

- increasing consumption when the value they get from using more electricity is greater than its price
- decreasing consumption of electricity when its market price is greater than the value consumers may forego by not using electricity, plus any cost of operating DR.

In aggregate, these individual decisions to flex demand help to allocate available electricity to its highest value use. When supply is short relative to demand and prices rise, lower valued uses stop, making supply available to higher valued uses (as indicated by consumers who are willing to pay the higher prices).

This observation holds when traders, rather than consumers, are directly exposed to price risk in the wholesale market. Traders can offer to pay consumers on fixed price contracts to (induce them to) reduce demand – i.e. either Type 1 or Type 2 DR. In that case, consumers will compare the gains they get from reducing demand (the direct reduction in electricity expenditure plus any inducement[16]) to the value foregone by not using electricity.

Lowering the cost of ensuring security of supply

Similarly, demand flexibility also supports the efficient resolution of demand and supply imbalances that risk the security of supply (compared to involuntary or administrative load shedding).

When available electricity generation or grid capacity is insufficient to meet local demand, scarcity prices apply at the relevant nodes. This provides an incentive for DR, discouraging lower value consumption (while equally encouraging offers of supply from generation with higher costs).[17]

As lower value consumption self-selects out and allows available supply to go to higher valued uses, voluntary consumer-driven DR 'solves' (even if imperfectly in reality) the information

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[16] An inducement might include future reductions in prices for electricity outside peak demand periods.

[17] As noted earlier, while consumers may have hedges that protect them from price risk, this leaves those offering the hedges exposed to price risk and they have incentives to minimise the downsides, including by offering incentives for DR. The exposed parties searching for DR have an incentive to get DR at the lowest cost to them, which will be offered by parties with the lowest opportunity cost.

problem of how to 'ration' demand efficiently at least cost (efficiently and to the long term benefit of consumers overall).

Administrative approaches to load control do not have the information (nor the incentives) to sort demand by social value to any way near the same extent – hence why administrative load control is best used as a last resort intervention.

Wider benefits

If DR is at sufficient scale in the context of the wholesale market, it has potential to reduce wholesale market prices, price volatility, and generation and network investment costs (by reducing peak capacity that networks need to accommodate).

Increased demand flexibility is useful alongside intermittent generation, such as wind and solar generation, and a potential substitute for peaking generation.

Demand flexibility puts a check on generators' offers and, through battery storage and other technologies that allow consumers to time-shift their load, has the potential to extend the number of participants in the market improving productive efficiency (e.g. pushing down prices).

These potential benefits of lower electricity prices and network costs (compared to a world with less effective DR) provide a potential rationale to facilitate the participation of additional flexible demand in the wholesale market.

When demand response is not beneficial

DR is not a free resource. Crucially, DR means that consumers forego the value they get from using electricity.

DR is not beneficial if it is not avoiding a cost, and if the avoided cost of electricity is less than the cost of providing the DR – the value consumers forego by not using the electricity (including from lost production).[18]

Any arrangements to facilitate DR therefore need to be designed to better elicit a beneficial, efficient amount of DR.

DR may have the effect of reducing electricity prices (or the cost of network investments). But it should not have the *aim* of reducing prices to some 'acceptable' level.

Prices are the outcome of a market process that balances demand and supply. Wholesale market prices provide important signals about the cost of providing electricity, and the value that consumers attach to using electricity (willingness to pay). Prices inform use, supply and investment plans.

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[18] The issues extend to network pricing. For example, time-of-use prices and injection rebates that are not aligned to, and targeted at avoiding, network costs are likely to provide incentives for consumers to invest in DR to avoid these inefficient price signals and shifting the costs to other consumers.

A DR intervention with the aim of suppressing prices to some ‘acceptable’ level will interfere with this price discovery process. It will likely result in demand and supply imbalances and allocative and dynamic efficiency losses. Lowering prices in this way risks:

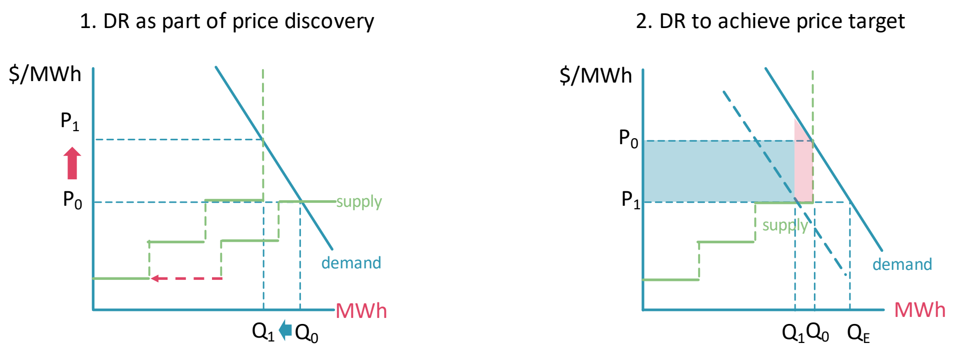
- discouraging offers from higher cost supply that consumers may have been willing to pay, and distorting signals to invest
- choking demand by consumers with high valued uses who would have been willing to pay the higher prices
- encouraging growth in underlying demand given suppressed prices
- paying for DR by lower-valued demand that would have self-selected out at higher prices.

See Figure 4.

There are also transaction costs and deadweight losses associated with raising funds and paying for DR incentives.

Nor should DR be used to correct for, or address, market or policy imperfections that might, for example, impede investment in generation, or supply of fuel, or cause environmental externalities. Such imperfections are better tackled with responses targeted directly at the specific problem. (See Hogan 2009.)

FIGURE 4: USING DR TO MANAGE PRICES CAUSES EFFICIENCY LOSSES



Scenario 1 starts with supply offers that would satisfy Q_0 demand at price P_0. But in the event some supply is not available lack of wind means supply is less than expected (reduction indicated by red arrow).

In the absence of other generation, prices rise to scarcity price P_1 to ration demand to available supply at Q_1. The demand that self-selects out is not willing to pay P_1 because the value to the consumer of using that electricity is less than P_1. This DR is beneficial and provides efficient price signals to inform consumers and generators about future use, supply and investment.

In Scenario 2, a DR initiative is put in place to suppress the market clearing price P_0 to P_1, considered ‘more appropriate’ as it is in keeping with recent history. The DR settles quantity at Q_1. The initiative results in a deadweight (efficiency) loss, as indicated by the red shaded area: there is some unused supply that consumers would have been willing to pay for. The main effect is a transfer of surplus from producers to consumers (indicated by the blue shaded area). At P_1 there is also unmet demand Q_E-Q_1. The price does not adjust to reflect the scarcity, and does not provide an efficient signal to consumers or generation It leaves the question how the DR is paid for in the first place.

3. Estimating potential DR

3.1. Approach

Classification

The discussion above set out high level economic and behavioural considerations for industrial consumers:

- the main trade-offs, namely between the value of providing DR and the costs of doing so
- whether the size of potential returns from offering DR are worth a consumer's attention (vs core business) or risk.

The aim of this section is to draw out relevant indicators of these economic considerations and match them to indicators of technical feasibility as a practical framework for high-level estimates of economic DR potential by consumer segment.

It draws out a way to classify demand response in terms of:

- low vs high opportunity cost
- short vs long notice processes (e.g. to facilitate scheduling or ramping down and up)
- short vs long duration availability
- low vs high transaction cost sources (as discussed above, e.g. the cost of searching, contracting, monitoring performance, enforcing).

Some classes of DR will be suited better for some DR applications than others: e.g. interruptible load, intraday response, seasonal.

Technical demand response capacity

Williams & Bishop 2024 have estimated the existing and emerging *technical* DR potential in New Zealand, finding this potential is 69% of national electricity use. Residential, commercial, industrial and agricultural sectors all offer potential.

These estimates are based on an investigation of the type of technology used and the suitability of its application for demand response. The study draws on EECA's Energy End Use Database and assigns levels of confidence to DR potential for each sector in the economy with controllable load[19], based on the presence of one or more of the following:

- energy storage, allowing outcomes for which electricity is used to be maintained without continuous supply from the grid

[19] That is, whether load can be interrupted or scheduled (e.g. delayed).

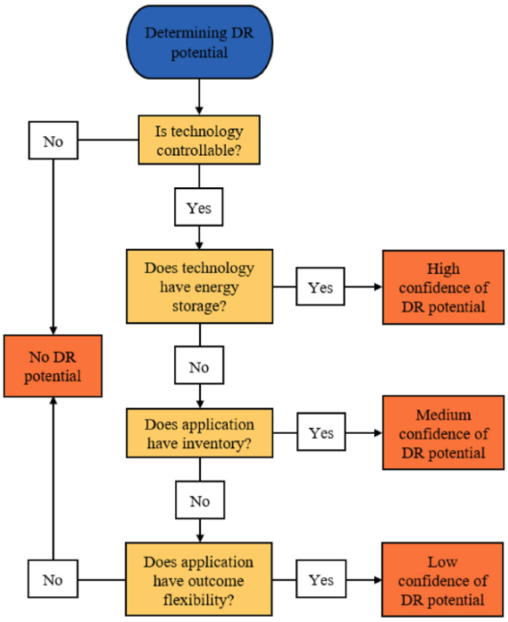
- inventories, allowing other workflows and outcomes to be maintained when electricity-intensive processes are slowed or stopped (while stocks last)[20]
- outcome flexibility, where there is tolerance for some fluctuation in an outcome (e.g. temperature) or timing (e.g. charging batteries).

These attributes may coincide in many cases, such as for cool stores where thermal inertia acts as storage and temperatures can be lowered to increase that storage without material negative effects on stored products.

This is a very broad approximation, as the assessment assumes a subsector's total energy use for a production process is counted as *potentially* available for DR.

See Figure 5.

FIGURE 5: LOGIC TREE TO RATE DR POTENTIAL



Source: Williams & Bishop 2024, Fig. 4.

20 Continuous processes such as chemical processes or those with tightly integrated supply chains (and so limited outcome flexibility) are more difficult to interrupt and are more likely to have high stop and restart costs compared to say batch-based processes. Having said that, firms that face higher cost of supply interruptions may have an incentive to invest in their own back-up supply, which may facilitate participation in DR.

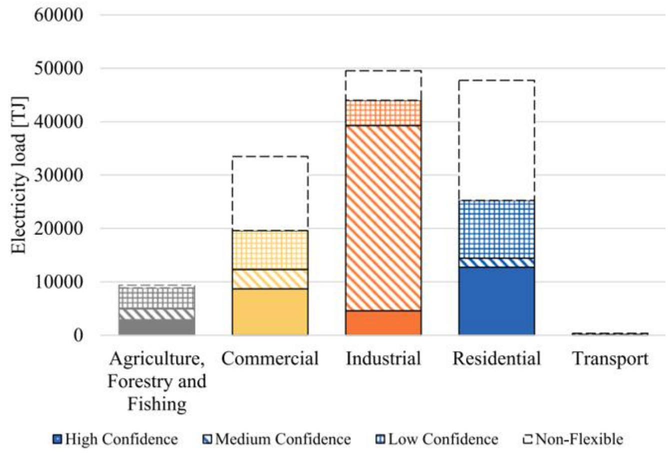
Williams & Bishop 2024 note:

> "A review of heavy industries shows DR potential is highest in cement and metal manufacturing, due to the flexibility of electricity demand for crushers, mills and smelting pots, and the large inventories typically present in those industries" [21]

> "Commercial electricity demand is typically less flexible than industrial demand due to technical and economic constraints … But inherent thermal storage and occupants' thermal comfort preferences mean space heating and cooling of commercial buildings is considered a good candidate."

Figure 6, also taken from Williams & Bishop 2024, summarises the results by sector. The estimate for the industrial sector includes an allowance for the future potential of 40% of process heat, and more than half of the 'medium confidence' estimate related to the smelter at Tiwai Point.

FIGURE 6: ESTIMATED DR POTENTIAL BY SECTOR 2021



Source: Williams & Bishop 2024, Fig. 5.

The authors concluded (p9) that "large demand response potential already exists … which can be accessed by retrofitting controllers and providing price incentives", particularly for residential and commercial hot water and heat pumps, commercial and industrial refrigeration, and electric motors in industrial processes with inventories.

As the authors note, theirs is a high-level assessment that does not account for specific process constraints or demand profiles. Nor does it consider the economic and behavioural factors that determine when such capacity would be valuable in the electricity market, whether it would be offered, and at what amounts, duration, and price.

[21] While the build-up of inventories offers parallels with energy storage, holding inventories is not costless and thus often an item that management will seek to minimise.

Economic viability

Technical potential is not the same as economic potential – DR that would be offered if incentives are right and there is a (reasonably low cost) way to trade DR with a counterparty or via some trading platform.

Economic viability requires a consideration of the potential private benefits of having demand side flexibility and providing DR, net of its costs.

There are different ways to test economic potential. One way would be to observe what demand response has been provided in the past, though that does not reveal DR that may have been available, subject to price and possibly investment in technology and know-how but was not offered.

ClimateWorks 2013 sought to address this information challenge through interviews with industry and market experts to provide an approximation of the "level of [industrial DR] potential … in response to a commercial offer" expressed as a discount on the full year electricity bill (p3).

One benefit of their approach is that these estimates of economic or commercially-viable levels of DR 'reveal', broadly speaking, consumers' and sector experts' own assessment of the costs and risks of offering DR – as an alternative to detailed and costly bottom-up modelling.

DR was defined as "the ability to shift or shed load for a period of about 2-4 hours, 5-10 times a year during a network or electricity system peak", under commercial incentives equivalent to a 5-15% discount on a consumer's total electricity bill (reflecting commercial incentives observed in some markets), and for a 20-30% discount (an upper end reflecting estimates of costs of peak capacity, which may be moderated by DR), and under different notice periods:

- 24 hours (100% of estimated DR potential)
- 2-4 hours (95% of estimated DR potential)
- 30 minutes (41%).

It identified "a significant commercially viable demand side response potential beyond what is observed as currently active in the market" (p4). At the high incentives levels this was estimated to be 42% of industrial demand at peak (or ~10% of total load at peak), and half that at the 5-15% incentive level (see p10).

The characteristics of firms or sectors with DR potential mirrored those in Williams & Bishop 2024: manufacturing with disruptable processes and inventories (such as metal fabrication, mining, electric motors).

The ClimateWorks results thus provide some datapoints by subsector and type of process to inform 'commercial viability' adjustments to make to the technical capacity identified by Williams & Bishop, at least for the industrial sector.

However, it has several limitations.

First, the definition of DR limits responses to those suited to relatively short interruptions 5-10 times a year, meaning there is an information gap with respect to longer duration interruptions as may be valued in dry years.

Second, ClimateWorks noted that "Importantly, incentives levels tested in this study are *generally higher* than those currently easily accessible in the National Electricity Market, *reflecting total aggregated economic benefits* rather than existing offers factors." (p4, emphasis added).

We therefore contemplated alternative ways to derive indicators of economic DR capacity, e.g.

- investment in managing electricity costs, as an indicator of sensitivity to changes in electricity prices and willingness to offer DR for plausible incentives
- high energy intensity and relatively slim margins (as an indicator of opportunity cost) that may increase willingness to offer DR for plausible incentives.

Attention and capacity to engage in demand response

DR technical potential may look large in absolute terms when considered at the level of entire industries or of system demand – 69% of demand according to Williams and Bishop. However, at a firm level electricity is not necessarily an important input cost. Median electricity costs as a share of total input costs – which excludes labour and capital costs – is 1.3%. There are industries where electricity is a significant share of input costs (Figure 7), but these are not typical.

This means most firms in most industries do not have strong incentives to invest in managing electricity costs. Savings from small reductions in a 1% input cost are simply not large and likely do not justify devoting resources to managing those costs.

Statistics New Zealand's surveys of energy use and management provide indictors of industries' differences in capability, attention or importance of engaging in energy management.[22] The surveys show that, on average[23], only 13% of firms have a defined energy management role – a person who takes responsibility for energy management – and only 11% have a dedicated budget for energy management.[24]

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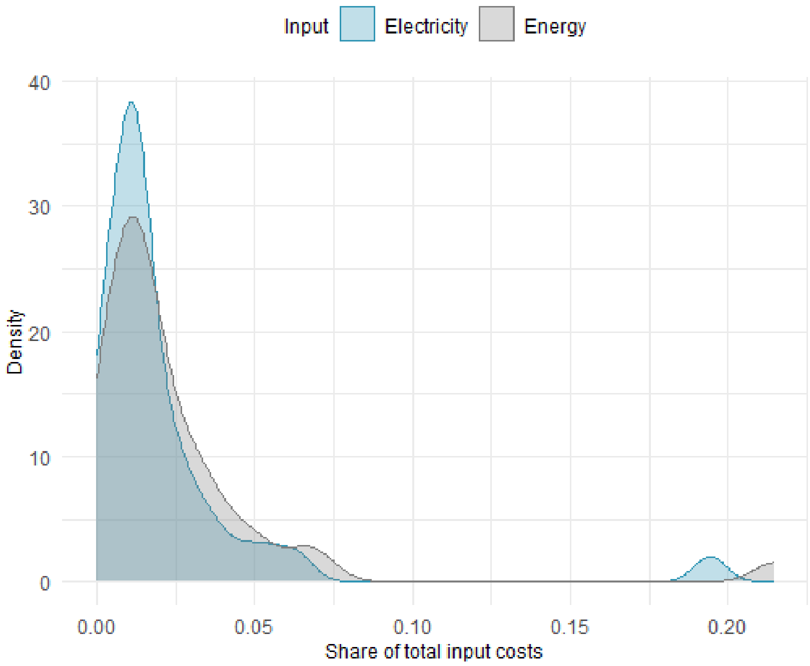
[22] These surveys took place between 2008 and 2018 and have now been discontinued. Though the findings are not current, we have no reason to believe that differences across industries would have changed noticeably since 2018.

[23] This is illustrative only as it is the average over industries' shares of firms reporting an energy management initiative rather than an appropriately weighted firm level average.

[24] These indicators of capacity are preferred relative to other measures captured in the surveys, such as installing energy saving technologies or undertaking energy audits, because those initiatives are more likely to speak to passive energy efficiency measures (e.g. changing lighting systems) rather than capacity to engage in DR.

FIGURE 7: ELECTRICITY AND ENERGY COSTS AS SHARES OF INDUSTRY INPUT COSTS
Industries captured in Williams and Bishop (2024), cost data from Stats NZ 2019 input-output tables. Excludes utilities industries.



The pulp and paper industry had the highest reported share of firms with defined energy management roles. Firms in the pulp and paper industry are twice as likely as the next highest ranked industry to report having a dedicated energy management role. This is to be expected given the energy intensity of the industry relative to earnings.[25]

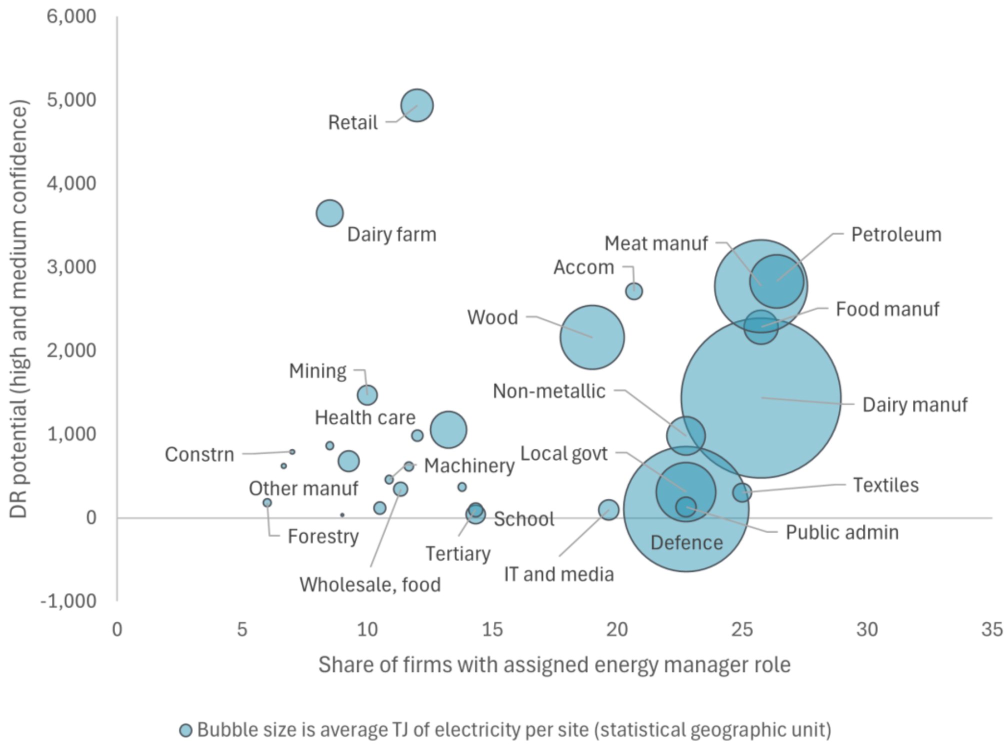
Other notable industries with higher-than-average rates of defined energy management roles include: primary metals production, dairy and meat manufacturing, petroleum and basic chemicals manufacturing, as shown in Figure 8.

The industries with higher-than-average rates of defined energy management roles are equally those that are more concentrated than other industries, in terms of electricity use. This can be seen in the bubble sizes in Figure 8 which show average industry electricity use per site.

[25] It also accords with the fact that, to date, the only dispatchable bids from industrial load came from Norske Skogg's pulp and paper operation at Kawerau.

FIGURE 8: INDICATOR OF DEMAND RESPONSE CAPABILITY VS POTENTIAL

Industries in Williams and Bishop 2024, pulp and paper and primary metals industries removed as outlying exceptions. DR potential is the sum of high and medium confidence DR potential in Williams and Bishop.



Dairy manufacturing has high electricity use per site[26] – reflecting that much of the electricity consumption is at comparatively few large central processing sites – while electricity use in retail food trade (labelled Retail) is 24 times smaller, on a per site basis.

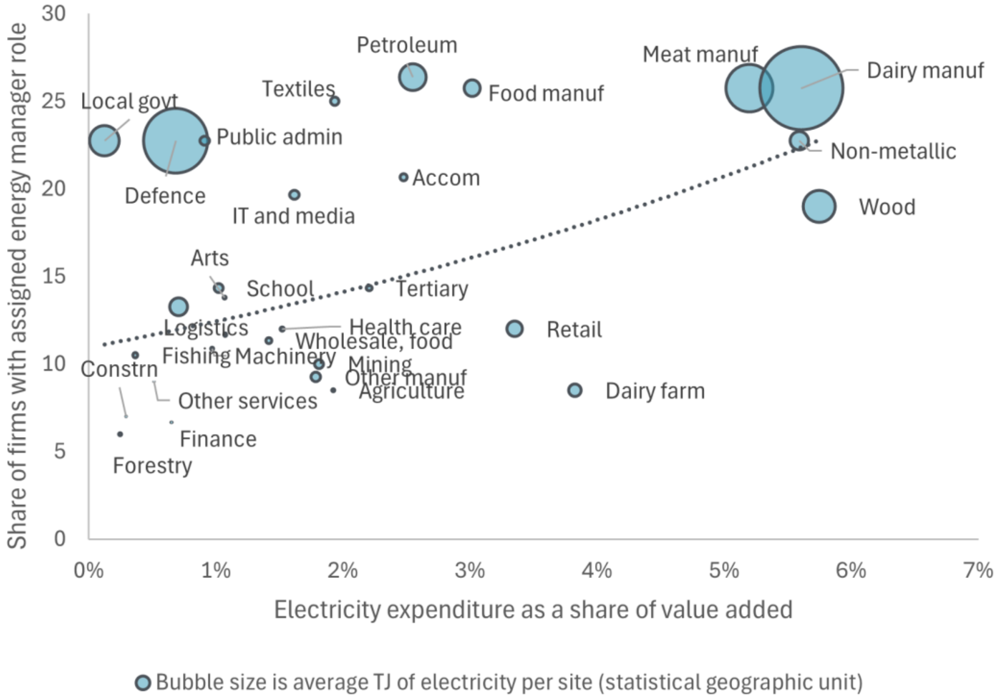
This point to coordination or transaction costs (how diffuse an industry is) as another factor that affects DR potential, and investment in capability.

The correlations imply that, even where there may be high technical DR potential, incentives to engage in DR will vary considerably across firms, to account for variations in the overall importance of electricity to firms' financial performance, and in coordination costs.

For example, industry-level measures of technical DR potential will overlook the fact that while retail trade has large aggregate DR potential, that DR is dispersed across a wide range of sites and firms with highly variable capacity or incentive to engage in DR.

[26] Albeit smaller than pulp and paper and primary metals which are outliers and have been removed from the chart, to improve visibility of less intensive electricity users.

FIGURE 9: ELECTRICITY COSTS CORRELATION WITH FIRMS HAVING DEFINED ENERGY MANAGEMENT ROLES



These indicators are not perfect. Industries with a lot of small firms and working proprietors won't have budgets or roles specifically applied to energy management but they may still have an eye on managing energy costs and in some cases this could extend to DR. Dairy farmers are an example of this. A farmer or sharemilker who can shift milking back an hour might happily do so to take advantage of time-of-use pricing. But there won't be an assigned role or budget for making that decision.[27]

Nonetheless, these are a useful guide as indicators of capacity to realise DR potential. And they point to organisational capacity to engage in DR being concentrated in a handful of industries.

The effect of electrification on these indicators is ambiguous. There are reasons for and against expecting firms to manage electricity demand more actively in an electrified future.

Higher use of electricity could certainly increase returns to effort from managing electricity costs and so increase attention. In some cases, newly electrified loads will have increased technical flexibility that makes energy cost management easier or easier to automate. And electrification could drive up prices for a while and that would sharpen firms' attention to electricity costs.

27 Anecdotally, we are told that there are dairy farmers who do precisely this.

But, for most firms, the effects are not likely to be large as a share of expenditure or income. Electrification will not, in and of itself, alter overall energy use as a factor of production. Any increase in incentives to actively manage electricity demand could easily be offset by increasing costs of (or returns to) other factors of production, such as wages or major input materials.

At a macro level, if services industries continue to increase their share of the economy there could be a relative decline in the number of energy intensive industries with a strong focus on managing electricity costs.

Alignment with system peaks

The value of DR, and incentives to respond, will be highest during periods of system demand peaks. That being so, some adjustments need to be made to aggregate industry-consumption (MWh) measures to arrive at measures of industry demands on system capacity (MW).

This is an imprecise exercise because data on industry load profiles is sparse.

We have reviewed data on hourly, weekday, and seasonal demand profiles by energy trader by point of connection in order to analyse the load profiles of large (typically non-conforming) industrial load, isolate demand that has distinctly residential peaking patterns, and analyse other load that we assume is commercial or industrial. This analysis has been used to form assumptions to convert consumption to estimates of MW load.[28]

By default, we assume that large industrial load is flat and that contributions to system peaks (in MW) are equal to energy consumption divided by the number of hours in a year. Though demand may fluctuate, we find evidence for fairly consistent levels of load throughout the day for many large industries. This accords with the presumption that large capital- and energy-intensive plants are run close to capacity if they can i.e. close to full capacity 24-7.

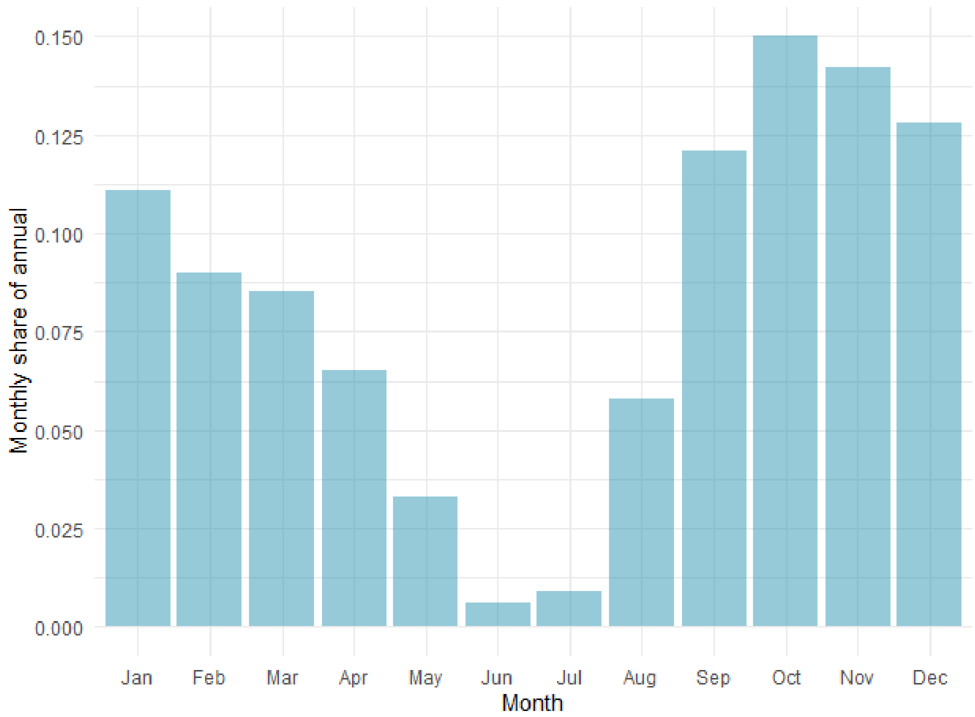
We are also aware that smaller (but not necessarily small) energy intensive firms and industries do not have flat load profiles. These industries are more likely to have load that ramps up in the typical morning peak in the system (around 7am) and declines late afternoon or early evening, unless the plant is running overtime shifts. These industries are also more likely to have lower consumption during summer holiday months.

Furthermore, primary sector activity tends to be low during peak winter energy demand months. For example, milk production (see Figure 10) and meat production and irrigation demand are highest in warmer months and low during peak winter demand months.

[28] The points of connection we analysed were ASB0661, EDG0331, GLN0331, GLN0332, KAW0111, KAW0112, KAW1101, KIN0111, KIN0112, KIN0113, KIN0331, MNG0331, MNI1101, TNG0111, TNG0551, TWI2201, WHI0111, WHI2201. We analysed reconciliation data for calendar years 2022, 2023 and 2024.

FIGURE 10: PRIMARY PRODUCTION DECLINES SIGNIFICANTLY MID-WINTER

Monthly milk output. Meat follows a similar profile.



To improve on our default assumption, our approach has been to adjust estimates of MW of demand by making assumptions (informed by data, see Appendix 2) about shares of demand that occur during intraday peak periods (7 am to 11pm) and winter (June to August) intraday peak periods.[29] The results of these assumptions for estimates of industrial load (MW) are shown in Table 2.

29 These definitions for intraday peak periods and winter peak periods are deliberately broad because (a) our data on demand by industry is not very precise (b) DR may be valuable, for system cost minimisation, outside of periods of maximum peak load; albeit it is much less likely to be valuable during very low periods of demand overnight and at weekends.

TABLE 2: ESTIMATES OF HOURLY INDUSTRIAL LOAD

Sector	TJ	MWh	Default, MW	Intraday MW	Winter peak MW
Dairy Products	4,107	1,140,907	130	165	39
Electricity, Gas, Water and Waste	1,871	519,604	59	61	61
Fabricated Metals and machinery	500	138,792	16	18	16
Food processing (ex Dairy and Meat)	3,058	849,520	97	113	101
Furniture and Other Manufacturing	758	210,624	24	28	25
Meat Manufacturing	2,941	817,060	93	118	28
Mining	1,620	449,960	51	60	53
Non-Metallic Mineral Products	995	276,270	32	36	32
Petroleum and Basic Chemicals	2,882	800,511	91	94	94
Primary Metal and Metal Products	23,651	6,569,636	750	747	747
Pulp, Paper and Converted Paper	2,397	665,970	76	76	76
Textiles and clothing	347	96,429	11	13	11
Wood Products	4,946	1,374,013	157	177	158
Total	50,073	13,909,295	1,588	1,706	1,441

Estimation Framework

Our final assessment draws together the considerations outlined above, accounting for:

- Electricity volumes: size of (sub)sectors as indicator of significance and raw potential, adjusted for contributions to broadly defined peak demand periods
- Technical potential (from Williams and Bishop), covering controllability of the process, storage/inventory, and outcome flexibility
- Capacity and incentives to engage in energy management and DR, proxied by percentage of industry that reports having dedicated management roles
- Coordination and transaction costs, proxied by average electricity use by site
- Subjective assessments of commercial viability of DR (from ClimateWorks)
- Notice period and duration. ClimateWorks provides an indication of the availability of DR over different timeframes, which is important as there are different markets / requirements for DR, from short periods of instantaneous response to DR for a period of weeks or months at longer notice.

The quantitative assessment proceeds as follows.

We start with volumes of energy demand by industry, technology and end use from the EECA energy end use data base.[30]

We then replicate the assessment of technical potentials from Williams and Bishop (2024) to get a first order estimate of technical DR potential.

We adjust those technical potentials for organisational capacity to engage in DR. We treat capacity to engage as a qualitative indicator. We adjust the method used in Williams and Bishop (2024) by asking whether the industry in question has below-average intensity of electricity use per site and below-average shares of firms with a dedicated energy manager role. If the answer is "yes" we assume low capability or incentive to engage in DR and we downgrade the confidence level assigned by Williams and Bishop by one ranking e.g. high confidence downgraded to medium confidence.

This yields an adjusted set of achievable DR potentials, based on judgement. This set of potentials spans all commercial and industrial sectors.

For industrial sectors we further refine our estimates of DR potential using the ClimateWorks survey data to assess the scale of potential DR taking account of rates of participation conditional on incentives that could be paid to procure DR. The rates are measured in fractions of peak demand by industry and process.[31]

Two levels of incentive payments were used in the ClimateWorks survey to gauge potential DR. One reflected the cost of additional resources (network and generation) to meet an additional MW of peak demand ($350,000 in Australia in 2013). The other was around half that amount.

To help assess the scale of DR potential adjusted for commercial viability, we use the estimated rate of participation induced by the high-end payment.

Adding the ClimateWorks estimates to our data has the advantage that it tends to shed light on the extent to which DR potential differs when measured in terms of subjective assessments of commercial viability versus in-principle and technical assessments potential – sometimes lower and sometimes higher.

We are cognisant of the fact that the ClimateWorks data comes from a survey of commercial intentions some time ago (2013) and in Australia. There are several reasons why this is a problem, including differences in industries' profits, degree of competition and availability of alternative fuel sources.

But, in our view, the ClimateWorks numbers can be taken to capture operational and commercial differences across industries that are persistent across time – for example, the

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30 Energy End Use Database | EECA.

31 We match the ClimateWorks industry and process estimates to industries and processes in the EECA database. This includes clear one-to-one matches and approximate matches, given differences in sector/firm and process definitions.

extent to which a metals manufacturer might in fact be willing to shed some proportion of load for the right price, despite effects on output, while a paper manufacturer may not.

Absent other data assessing commercial viability of DR, we think the data holds sufficient insights that it could be used to gauge demand potential in New Zealand, subject to the caveat that it is a high level assessment that could be improved upon considerably.

3.2. Results

We find the scale of technical potential industrial DR (see Figure 11) ranges from 190 to 300 MW, roughly in line with what was observed by the Authority in its 2024 survey (250 MW from large industry, small commercial and industrial and electric boilers).

DR potential starts at around 300 MW, based on the assessment of technical potential with high confidence and our adjustment for expected industry capacity to engage in DR. These are shown in the bars labelled “DR potential” in Figure 11.

Our analysis suggest that winter peak DR potential is lower than in other seasons, due to reductions in primary sector load.

Further, our analysis suggests – based on the Australian survey evidence – that commercially achievable DR levels are likely a fraction (one half to two-thirds) of DR potential. Even with very high incentive rates (20% to 30% of bills) consumers are not willing to reduce load as far as technical potential suggests. This is depicted in Figure 11 in the bars showing DR given advanced notice of 24 hours and short notice of 2-4 hours.[32]

Potential for rapid (30 minute) or automated response – such as may be required for system balancing or reserves – is smaller again with DR ranging from 113 MW in the winter to 133 MW in other months.

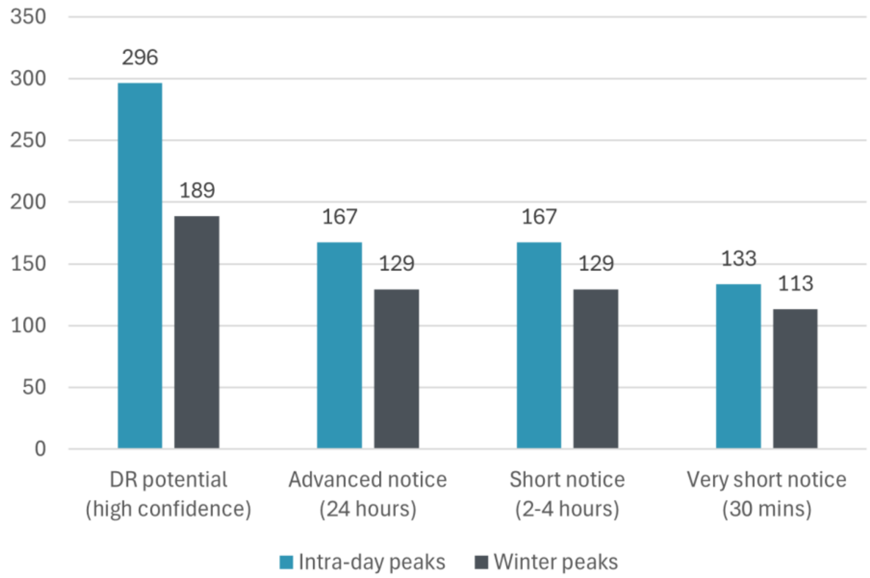
These numbers depart significantly from assessed technical potentials. However, they align perfectly well with observed DR behaviour including that no industrial load is offered as dispatchable demand and no industrial load is offered as interruptible load in the reserves market.

Most of the DR potential comes from outside the usual industries expected to provide DR – i.e. not large industrial users except in the case of meat and dairy (see Figure 12). This is down to assessments of limited production shifting in the large industrials – that these plants tend to run near capacity if they can.

[32] As the figure shows, ClimateWorks found no material difference in potential DR with 24 hours’ notice or 2-4 hours’ notice. They reasoned that it takes more than 24 hours to make changes to production plans, so extending notification time to 24 hours, from 2-4 hours, did not make any difference and that, implicitly, 2-4 hours was sufficient notice for non-automated DR, conditional on the firm having agreed to be part of a DR programme.

FIGURE 11: ASSESSED LEVELS OF POTENTIAL DEMAND RESPONSE

MW of DR. Response by notice period is potential adjusted for survey evidence on actual willingness to respond (share of peak MW) given a 20%-30% reduction in electricity bills.



This observation clashes with the fact that at least one large industrial user, NZAS, has undertaken substantial sustained DR (with limits on total amount of DR). This can, perhaps, be explained by the fact that this is an exception and one that was part of an agreement to secure a lot of electricity supply over a long period. Also, if averaged over a long period the potential DR in that agreement would be rather smaller than at face value.[33]

On the other hand, this assessment, which includes commercial as well industrial demand, is deliberately conservative – including only those sources of DR that were assessed as technically and organisationally feasible with high confidence.

Taking a conservative approach, one that results in lower-than-typical assessments of DR potential, is important because it helps avoid the problem that in-principle assessments of technical potentials tend to over-predict what can be achieved.[34] Furthermore, when it comes to smaller energy users and commercial demand, we have no data to assess the commercial feasibility of technically feasible responses.

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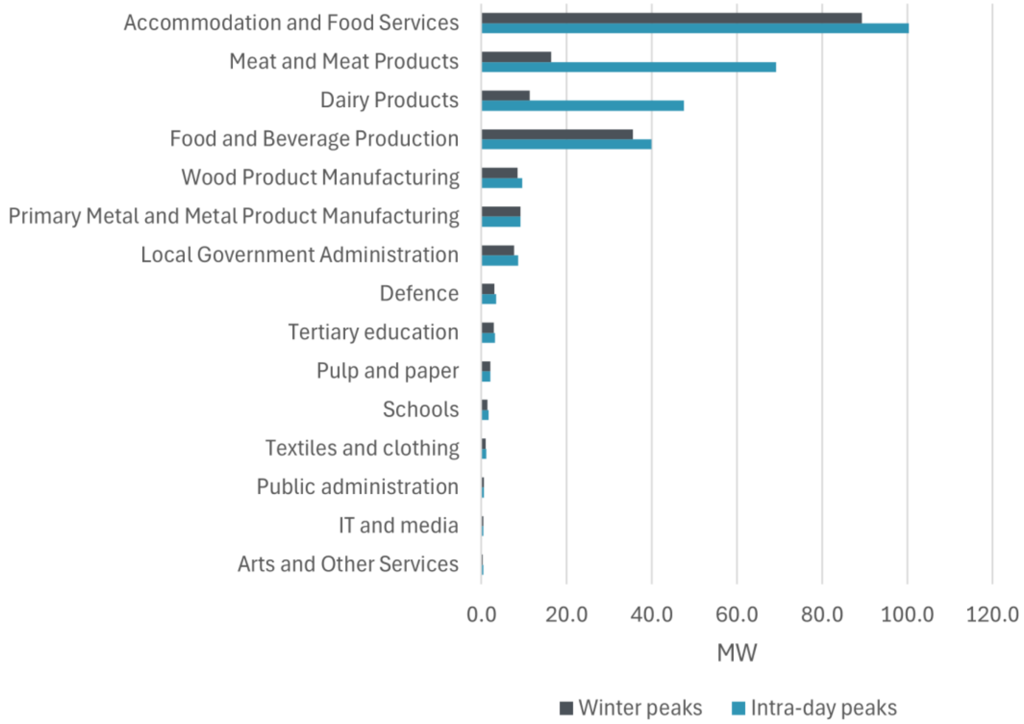
33 It remains to be seen if similar things can be said of Contact Energy's supply arrangement for NZ Steel's planned electric arc furnace, due in 2026. Reporting suggests that this is a long-term contract that includes DR, but how this will work in practice is unclear.

34 See e.g. Allcott and Greenstone (2012) and Appendix A of Cabot (2024).

FIGURE 12: DEMAND RESPONSE POTENTIAL BY INDUSTRY[35]

MW of potential, high confidence



Incentives might be able to deliver higher rates of demand response

That said, some sources of DR that are assessed as being technically quite uncertain (medium or low confidence in the Williams and Bishop analysis) are, in the ClimateWorks survey, made available **conditional on sizable incentive payments**.

Figure 13 shows the size of potential DR conditional on size of incentive payments, without excluding any potential DR due to degree of confidence about technical potential.

One key point arising from Figure 13 is that incentives to induce DR could, in principle, be much lower than the sorts of levels suggested by assessments of the incremental costs of peak capacity.

The high end of incentives in Figure 13, of around $250,000 to $300,000 per MW, are roughly in line with estimates of incremental cost of peak system capacity.[36] For example, Sapere estimated an incremental cost of 1 MW of peak demand of $240,000, in work for IPAG in 2021.

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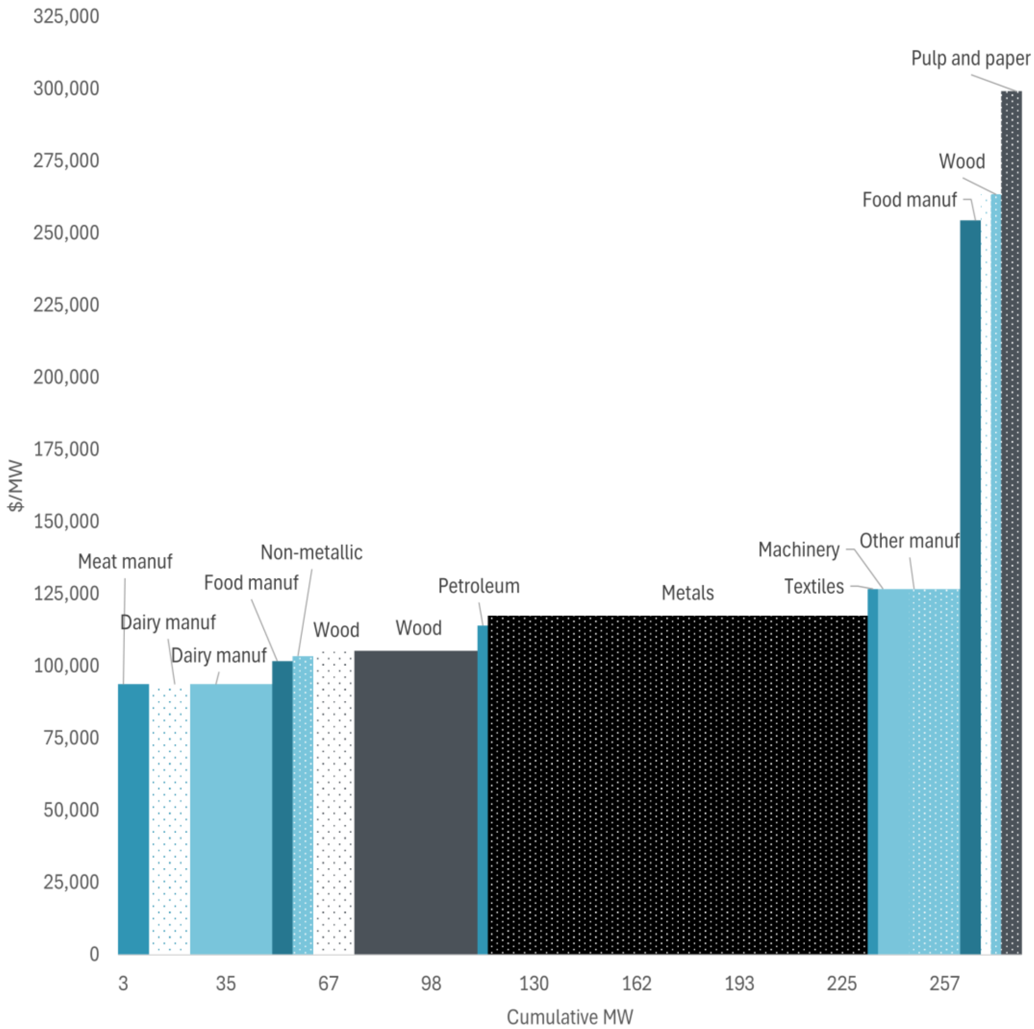
35 This chart includes all industries. Later we refine this scope to include only those more energy intensive industries for which we have estimates of DR potential given incentives, from the ClimateWorks research.

36 This gives us some comfort as to the usability of the ClimateWorks survey data for our purposes. The ClimateWorks high-end incentive level was calibrated to estimates of peak system capacity costs,

In general, the highest incentive rates induce relatively little additional DR.

FIGURE 13: INDUSTRIAL DEMAND RESPONSE CONDITIONAL ON INCENTIVE PAYMENTS

DR potential shown here is for Intraday Peak MW (not Winter Intraday Peak). Block patterns indicate confidence levels assessed in Williams and Bishop: solid blocks are high confidence, patterned blocks with solid backgrounds are medium confidence, and blocks with white backgrounds and dots are low confidence.



converted into fixed percentage reductions in load customers' bills. The incentive values in Figure 13 are based on the percentage bill reductions cited in the ClimateWorks study while the dollar values are those produced by applying the percentage reductions to estimates of industry average bills based on consumption and representative New Zealand prices per MWh from [Energy prices | Ministry of Business, Innovation & Employment](#).

Though incentives need to balance potential with value

These numbers do not represent the cost required to induce DR nor the "value" of DR. They are a very high-level estimate of how much DR might be achievable for a given level of incentive.

If an incentive was used to "secure" DR, the value of that response – to the market or to consumers - depends on e.g.:

- system capacity utilisation at the time of supply and thus avoided costs, relative to some counterfactual
- the amount of response, in aggregate, given that the value will decline as the size of the response increases because the size of avoided costs gets smaller
- the amount of incentive paid, if any (it is a cost that needs recovering[37])
- whether alternative sources of DR, e.g. from distributed residential battery storage, could be procured at a lower cost
- minimisation of perverse incentives to increase demand to procure incentive payments.

Ultimately, the value of DR will be the sum of benefits to the supplier of DR (price paid less incremental cost of supplying DR) and benefits to consumers (avoided costs less price paid to procure DR).

We do not have sufficient information to form a view on what the balance of benefits could be, overall.

We can say, however, that the value of incremental DR is potentially large. Assuming that incremental costs of system capacity are as large as $250,000 to $300,000 per MW and 1 MW of DR could be secured for around a third of that, then an incremental unit of DR could easily be worth more than $200,000.

Sustained demand response: costly and hard to do?

The above assessment is for infrequent DR of reasonably short duration to balance intra-day demand and peaks. More sustained demand reductions are of course possible, but they would carry potentially significant costs as they would imply substantial shedding of production.

Production shedding from sustained DR would be almost entirely unavoidable for large users that run their plants at high utilisation rates if they can.

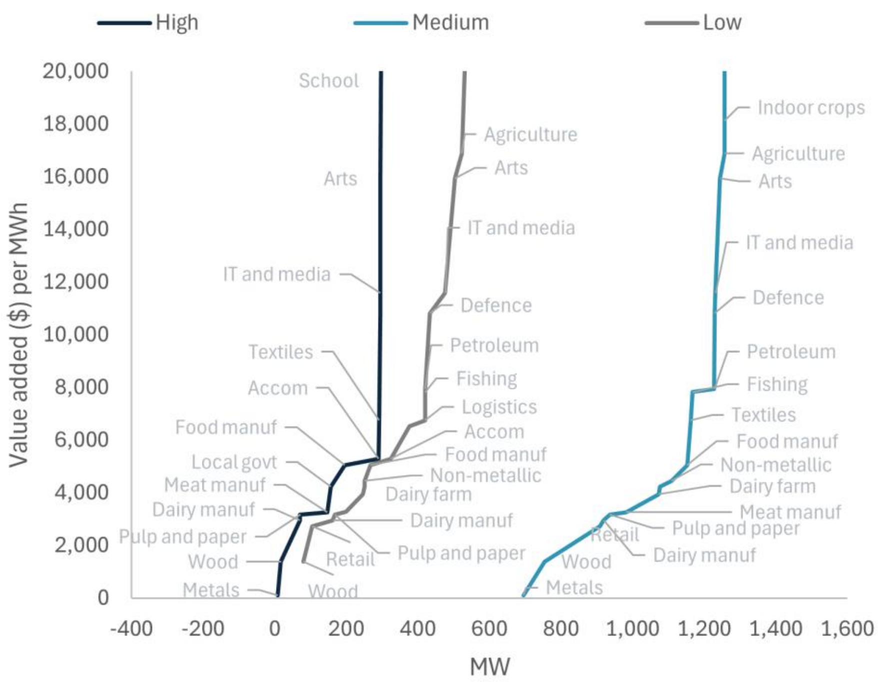
[37] This cost may simply be a transfer, in idealised circumstances, in which case it is not a net cost. But the existence of such a transfer does need to borne in mind to avoid assuming that this is a free lunch. Crucially, if DR is procured at the same price as incremental system capacity costs then consumers are neither better nor worse off if the DR is paid that price.

The shadow cost of DR includes the potential loss of value added (capital and labour income) which is many multiples of electricity costs. And while energy intensive production has low value-added per GJ of energy, the fact they use a lot of energy means the value at risk is very large.

For example, Figure 14 charts value added per MWh alongside MW of potential DR, grouped by level of confidence around technical feasibility of DR. Notice that disruption to services industries carries high per unit costs, but the area under the curve (the total cost) is small because the volumes are small.

FIGURE 14: SHADOW COSTS OF DEMAND RESPONSE, VALUE ADDED VS DR POTENTIAL

Illustrative measures of income loss from reduced production. All sectors, grouped by technical feasibility of DR: high, medium and low confidence (Williams and Bishop, 2024). Y axis truncated. Outlying (highest value) maximum value is $153,000 per MWh



Smaller users, in contrast, are more likely to have load profiles where demand can be shifted on a semi-permanent basis without, in theory, affecting overall production and potentially reducing costs. In practice, however, coordinating this at scale, for system-wide benefit, would be more costly than coordinating DR of large users.

Furthermore, for small industrial users that shifted load on a semi-permanent basis there might need to be a rearrangement of operating hours – e.g. extending shifts into the nighttime or into weekends. In some cases that could mean higher labour costs to compensate. So, there are no easy win-wins.

The one exception to this would be relatively passive loads that can be automated, like coolstores. Perhaps there is scope for sustained changes in load profiles in some industries –

though that would be more accurately described as structural changes in load profiles than DR.

That said, if such changes are thought to reduce energy costs then this raises a question about whether there are equipment-related costs or capability constraints that prevent such changes from occurring at scale.

3.3. Caveats

Our assessment is high level. Ideally it would have included finer grained analysis of industrial and commercial load. However this was not feasible for this assessment.[38]

The assessment also involved some high-level judgements, based on limited data. Notably, our adjustment for industry incentives and capability has a material effect on the amount of DR that is assessed as being available, with high confidence in Williams and Bishop. So too do our adjustments for seasonality of demand and our use of ClimateWorks survey results for proportions of peak demand offered, subject to incentives.

The effects of our adjustments are summarised in Table 3. The baseline shows average MW during peaks as we have defined them (weekdays 7am to 11pm). The technical DR potential, assessed with high confidence, is the assessed potential in Williams and Bishop for industries excluding residential demand. The capability adjusted figures are the measures after we adjusted for incentives and coordination costs.

The capability adjustment drops 8 sectors from those assessed as having some DR potential with high confidence.[39]

Seasonal adjustment further reduces DR potential, for winter peaks, by approximately one-third, reflecting reduced demand for electricity from the primary sector in winter.

TABLE 3: INDUSTRIAL DEMAND RESPONSE CAPACITY, EFFECTS OF ADJUSTMENTS

	Intra-day peaks		Winter peaks	
	Technical (MW)	Capability adjusted (MW)	Technical (MW)	Capability adjusted (MW)
Baseline system MW (averages)	5,149	5,149	6,600	6,600
DR potential (high confidence)	619	297	413	189
Advanced notice (24 hours)	489	168	353	130
Short notice (2-4 hours)	489	168	353	130
Very short notice (30 mins)	455	134	337	114

38 It is not infeasible, just not possible in the time available.

39 Dairy Cattle Farming; Financing, Insurance, Real Estate and Business Services; Fishing, Hunting and Trapping; Health Care and Social Assistance; Non-Dairy Agriculture; Retail Trade - Food; Wholesale and Retail Trade - Non Food; Wholesale Trade - Food.

4. Conclusions

4.1. Key findings

Overall, we find that industrial DR:

- is substantially smaller than often thought, due to commercial constraints
- is probably not higher than 6% of typical daily peak demand and 2% of typical winter peak demand, if relied upon at short notice
- can be expensive, with substantial incentives required to procure DR and significant income losses if load reductions are sustained.

From participants' perspective, industrial DR is but one way of managing price risk.

From industrial consumers' perspective, costs of DR relate not only to interrupted or lost production, but also to attention (e.g. energy managers) and capability (specialist technology and knowhow). Other forms of hedging price risks avoid such costs.

Further, electricity is not, with a few exceptions, necessarily an important enough input cost to justify investment in attention, capability, and production interruption.

4.2. Next steps

High level assessments are useful in the short term for testing thinking. However, they offer an only very partial guide for policy purposes i.e. if interventions are being considered.

This means one of two things, or both:

- policy that seeks to support DR should aim for learning, i.e. interventions that aid in information discovery in the first instance, whether for the purposes of regulation, system operation or decision making by industrial consumers
- in-depth market analysis of potential gains from trade – using detailed data on the actual operations of real participants, potential buyers and sellers of DR, so that technical conjecture can be matched to commercial and operational facts and an assessment can be made of system-wide effects of DR.

Appendix 1 References

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Appendix 2 Estimating industry intraday and winter intraday peaks

We converted measures of annual TJ of electricity use by industry into estimates of MW of demand during intraday peaks and during winter intraday peaks.

For industries dominated by large industrial load we used observed load profiles of specific plant, using reconciliation data on load by trade by GXP. These estimates were applied for primary metal manufacturing, pulp and paper manufacturing and dairy product manufacturing.

Primary metals and pulp and paper plants run approximately 24 hours 7 days a week and thus have peak load (MW) approximately equal to Annual TJ x MW/h/TJ x 8760. Though these plants have periods of downtime, e.g. for maintenance, and tend to have slightly lower demand during winter and intraday peaks, our estimates of peak MW are not very sensitive to these nuances.

Our observations for dairy manufacturing suggest that load is typically 50% lower at weekends (and during holidays) than during weekdays. In addition, we used data on seasonal production profiles for milk production to estimate typical winter peak demand for dairy product manufacturing (see Figure 10 in body of report).

Our approach to estimating peak dairy MW is quite crude, but the best we could do with readily available data and in the time available. This approach ignores the considerable variation in: the types of products produced by different dairy processing plants and companies, seasonality of operations, and different fuel sources.

For other industries, we considered whether they are likely to have a few major industrial energy users or otherwise have high levels of capacity utilisation consistent with relatively flat loads observed directly for large industrials.

We have assumed that meat and meat product manufacturing has the same daily and seasonal load profile as dairy product manufacturing.

We also assumed that the petroleum, basic chemical and rubber product manufacturing industry had the same intraday load profile as for dairy.

For other industries, we adopt a single aggregate measure of industrial load profiles. This load profile was constructed using reconciliation data by GXP[40] and trader where industrial and commercial loads could be identified by excluding demand that exhibited distinctive

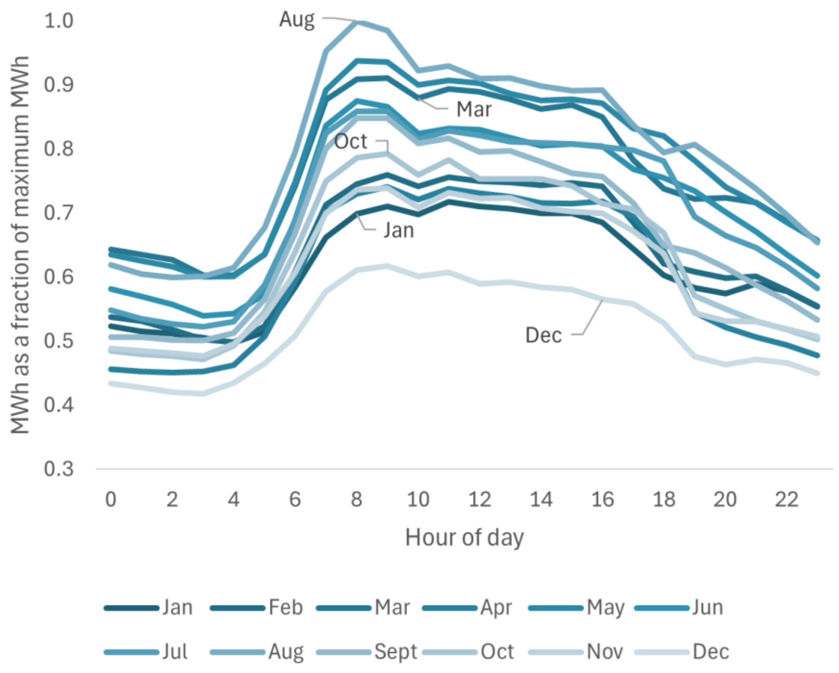
[40] The points of connection we analysed were ASB0661, EDG0331, GLN0331, GLN0332, KAW0111, KAW0112, KAW1101, KIN0111, KIN0112, KIN0113, KIN0331, MNG0331, MNI1101, TNG0111, TNG0551, TWI2201, WHI0111, WHI2201. We analysed reconciliation data for calendar years 2022, 2023 and 2024.

residential demand profiles, company-specific industrial demand, or industry-specific load in the case of distinctive demand profiles for irrigation.

The load profile we used as a generic industry profile is shown in Figure 15.

The data we used to do this is only a subset of national demand and industrial demand. Further work could extend this analysis to produce more accurate measures of industrial demand profiles.

FIGURE 15: GENERIC INDUSTRY WEEKDAY HOURLY AND SEASONAL LOAD PROFILES



For wood product manufacturing and petroleum and chemical manufacturing we had data on company-specific load profiles. However, we did not use these as we did not consider them to be representative of industry demand. For petroleum and chemical manufacturing we were conscious that the load profile of a single entity, at Motonui, is not likely representative of such a heterogeneous industry category. For wood product manufacturing we observed load profiles for large plants with fairly high capacity utilisation and flat loads. However, we are aware that the industry has many moderately sized firms/plants, in terms of electricity use.

Our estimates of peak demand are industry-level estimates. All industries contain a range of firms of different sizes with different operational requirements. Large firms that operate more often will tend to dominate industry-level load profiles.

SENSE PARTNERS

DATA LOGIC ACTION

Appendix D Format for submissions

Submitter	

Questions	Comments
Q1. Do you agree with our approach of focusing on industrial demand flexibility as an early initiative to enable demand flexibility more broadly? Why/Why not? Do you have any information to indicate that demand response from other consumer types may be more readily accessed?	
Q2. Do you agree with our estimates of the potential industrial demand flexibility capacity available in New Zealand currently and into the future? Why/why not? Do you have any evidence to support a materially different estimate?	
Q3. Do you agree with our focus on intra-day demand flexibility for this initiative? Why/why not? What other approach would you suggest?	
Q4. Are there any other ways that currently enable industrial demand flexibility in New Zealand?	
Q5. Do you agree with our description of the barriers affecting the provision of industrial demand flexibility? Why/why not? Are any other barriers relevant to the provision of demand	

flexibility from other consumer types?	
Q6. Do you agree that existing incentives and contracts for demand flexibility are resulting in inefficiently low levels of demand flexibility?	
Q7. Are you aware of any additional barriers to enabling more industrial demand flexibility?	
Q8. Do you agree with our vision for industrial demand flexibility? Why/why not?	
Q9. Do you believe that this vision is applicable to other forms of demand flexibility, or to flexibility more generally?	
Q10. Do you agree with our view that demand flexibility providers should be able to receive payment for providing flexibility services that exceeds avoided energy costs, provided the demand response is efficient (as defined)? Why/why not?	
Q11. Do you believe that a different level of payment would be appropriate? Why/why not?	
Q12. Do you agree with our proposed guiding principles? Why/why not? Are other specific considerations which you believe should be included in the evaluation framework?	

Q13. Do you agree with our view that there is currently insufficient potential industrial demand flexibility to justify the establishment of new market mechanisms or platforms other than the proposed ERS and standardised demand flexibility product?	
Q14. Do you consider there are other cost-effective measures that can be implemented urgently to enable industrial demand flexibility to support reliability and efficient in the wholesale market?	
Q15. Do you agree with our proposal to establish an ERS? Why/why not?	
Q16. For demand flexibility providers – do you consider it likely that you could make demand flexibility capacity available for an ERS in time for Winter 2026?	
Q17. Do you agree with our proposal to investigate a standardised demand flexibility product? Why/why not?	
Q18. Do you support our other proposed roadmap actions? Why/why not?	
Q19. Do you believe there are other actions that we should consider in the roadmap? If so, please outline the actions and rationale.	
Q20. Do you support the proposed sequence and timing of actions in our	

proposed roadmap? Why/why not?	
Q21. Is there anything else relevant to this issue that the Authority should consider? If so, please provide any relevant information to support the Authority's consideration.	

Appendix E Glossary of key terms

Additionality	In this context means that resources procured are 'additional to' what would have happed if the mechanism had not been put in place (eg, continued as business as usual)
BESS	Battery energy storage systems
Commercial market making	A workstream that uses a paid provider to make the electricity futures market more efficient.
Controllable load	Load (eg, hot water cylinders) that a consumer (or someone on its behalf) can reduce to help reduce demand during peak times or to respond to a grid emergency.
Dispatchable Demand (DD)	Regime that enables demand-side participants to compete with generators to set the spot price and be able to respond more efficiently to wholesale market conditions.
Dispatch notification	A low-cost path to allow small scale generation and aggregated resources to directly participate in the spot market.
Demand flexibility	Consumers adjust the time and/or the amount of their electricity consumption (demand) in response to market and network conditions. Generally, this involves reducing demand in response to high wholesale prices or congestion in the electricity network.
Energy Competition Task Force (Task Force)	The Authority and Commerce Commission jointly established the Task Force to investigate ways to improve the performance of the electricity market.
Flexibility services	These draw on consumer flexibility and distributed energy resources (eg, controllable electric vehicle chargers or solar generation) to provide support services to distribution networks, the transmission grid and energy markets.
Gentailer	Generator-retailer – an electricity company that operates both as a generator and a retailer of electricity (eg, Mercury, Meridian).
Distributed energy resources (DER)	Often smaller generation units that are located on the consumer's side of the meter (eg, rooftop solar).
Electricity distribution businesses (EDBs)	Also called network companies, distribution companies or distributors. These are lines companies that own and operate the lower voltage power lines and distribution networks in local areas. These connect to the national grid to deliver electricity to homes and businesses.
ERS	Emergency Reserve Scheme

Explicit demand flexibility (Type 2)	Consumers reducing their consumption by a defined amount in response to an instruction from a supplier or the system operator, or when a consumer chooses to on-sell electricity previously purchased for their own use, in return for an agreed payment.
Flexibility provider	An actor (such as third-party aggregators) who provides flexibility services by making temporary changes to the way they, or contracted consumers, consume, generate, or store electricity when requested by the electricity networks or system operator.
Hedging	A risk management strategy that involves buying and selling futures contracts to protect energy traders from unexpected or adverse price fluctuations.
Implicit demand flexibility (Type 1)	Consumers adjust their consumption in response to price signals.
Industrials	For this initiative, the term includes large direct-connect consumers along with medium size commercial and industrial consumers that are not directly connected to the transmission system, but have large, disaggregated loads (eg, supermarkets).
Intra-day flexibility	Flexibility to made available to account for short-term variability during the day (as opposed to seasonal flexibility).
Intermittent generation	Electricity generation that relies on a variable resource that is not stored (eg, wind and solar).
Low residual events	Events when the remaining offered capacity (residual) for a given trading period drops to a level that increases the risk of a grid emergency and potential demand management.
Market Development Advisory Group (MDAG)	One of the Authority's advisory and technical groups. The group provided independent advice on issues that relate to pricing and cost allocation, risk and risk management, and operational efficiencies. Group was formed in October 2017 and disbanded in February 2024.
Negawatt payments	Negawatt payments are payments at the wholesale price for electricity not consumed.
Network solution	Solutions that require capital expenditure in network equipment (eg, new transmitters).
Non-network solution	Solutions that require operational expenditure to postpone capital investment in the network (eg, demand response).
Peak	A peak period is a period of high electricity demand and corresponds to high pricing.

Peak capacity issues	Issues with the availability of generation and transmission assets to meet peak electricity demand at any point in time.
Power Innovation Pathway	Authority's approach to provide enhanced regulatory support to high-value initiatives to accelerate New Zealand's energy transition.
Retailer	A company that sells electricity or gas to consumers.
Reliability and Emergency Reserve Trader (RERT)	A mechanism administered by Australian Energy Market Operator to maintain power system reliability and system security during periods of high demand-low supply using reserve contracts.
Seasonal flexibility	Flexibility to be made available for a long period of time, such as weeks or months (as opposed to intra-day flexibility).
Shaped product/contract	A customised financial instrument designed to meet specific load profiles or consumption patterns of end users. Unlike standard products, shaped products can account for variations in demand over different times of the day or seasons, allowing customers to better match their energy supply with their actual usage.
Spot market	The spot or wholesale market is a marketplace to buy and sell electricity.
Standardised Flexibility Product Co-design Group (Co-design Group)	One of the Authority's advisory and technical groups. It worked with the Authority to develop a new standardised super-peak hedge contract (that started trading from January 2025).
Time-of-use tariffs	A feature of variable pricing. The price a consumer pays changes throughout the day (cheaper or even free during off-peak times)
Value stacking	Managing a group of resources to provide multiple electricity services with the goal of maximizing economic and operational value.
Value of lost load (VoLL)	A measure of the cost of outages experienced by customers (ie, trading loss during business hours)
Wholesale market	The wholesale or spot market is a marketplace to buy and sell electricity.