2023 Input Methodologies Review – Draft Decision

Contact Energy Submission

19 July 2023

Introduction and Summary

1. Thank you for the opportunity to provide our views on the 2023 Input Methodologies Draft Decision (Draft Decision). The Commerce Commission (the Commission) has undertaken a thorough and carefully considered review across the input methodologies. We broadly agree with the conclusions reached.
2. In this submission we highlight five issues that the Commission should consider in reaching its final decisions:
    a. **Connection costs** are now one of the most significant barriers to decarbonising industry in New Zealand. The draft IMs do little to improve this situation, and in one cases make it significantly worse. We propose a separate workstream is established in conjunction with the Electricity Authority to develop the right set of rules and incentives on connection costs.
    b. **Strengthen protection for consumers from price shocks** by ensuring that the 'revenue smoothing limits' are firmly applied in practice over all lines charges. This will ensure that price change risk will sit with the party best placed to manage it.
    c. We show that the **WACC percentile**, used for setting prices should be set at 60th percentile. The weight of evidence indicates that the WACC percentile should be materially lower than its current level.
    d. We support the **indexation of Transpower's RAB** and consider that this change should be made without delay.
    e. **Innovation allowances** should require proof of additionality, showing that the innovation would not occur without the funding. They also must not distort potentially competitive services like non-network solutions.

Connection costs

Summary of Connection cost recommendations:

1. Do not implement the proposed 'large connection contract mechanism' for EDBs as this would substantially disincentivise large electrification projects and distribution connected renewable energy developments.
2. Establish a joint project between the Commission and the Electricity Authority to set the appropriate rules and incentives for connection costs. This project should focus on:
   a. Requiring better information on connection costs
   b. Ensuring that new connections are only charged for the minimum cost to connect that customer, and no more.
   c. Ensuring that EDBs are supported to undertake efficient over-build at the same time as a new connection to take advantage of economies of scope and scale.
   d. Ensuring that EDBs provide non-firmed connections where possible.

3. To meet New Zealand's emissions reduction commitments a significant part of the economy will need to be electrified. That is why 'growing demand' is one of the key limbs of our strategy to 'lead New Zealand's decarbonisation'.[1]
4. As noted by the Climate Change Commission, a big part of New Zealand's decarbonisation journey will come from electrifying process heat users.[2] Most of these conversions will take place on distribution networks and will require upgraded connection capacity.
5. The current connection cost settings frequently result in excessive costs being charged to customers, which is creating a significant barrier to process heat conversions. This is a very material issue as the cost of a connection can often be the single largest cost in an electrification project. We understand that this can also be a barrier for EV charging networks.[3]
6. The costs of new or upgraded connections for customers have largely been ignored in the draft decision. Instead the focus has been on the increased administrative burden connection requests can place on EDBs, and the Commission.

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[1] https://contact.co.nz/-/media/contact/mediacentre/presentations/contact-energy-capital-markets-day-2023-presentation.ashx?la=en, p8
[2] https://www.climatecommission.govt.nz/public/Advice-to-govt-docs/ERP2/draft-erp2/CCC4940_Draft-ERP-Advice-2023-P02-V02-web.pdf, ch9.
[3] https://www.energynews.co.nz/sites/default/files/2023/06/07/concept_consulting_brief_for_drive_electric_on_distribution_network_access_1_1.pdf

7. Excessively high connection costs are in part driven by the incentives established in the input methodologies. A large part of the costs of a new connection are charged as a capital contribution. These costs are treated as a recoverable cost and netted off the revenue allowance. That means they effectively sit outside the regime and are not subject to the normal efficiency incentives.
8. In theory, because capital contributions are only intended to cover the actual costs incurred by EDBs, they should be indifferent to the cost, and not have an incentive to build inefficiently. Further, the Commission believes that a connecting party will have some negotiating power, limiting the ability of the EDB to over-charge.
9. These assumptions have proven to be incorrect in practice. As we show below:
    a. even large customers (outside some data centres) have little bargaining power;
    b. there is an incentive to add additional costs into connections charges to avoid the IRIS disincentive for over-build; and
    c. there is limited incentive to seek out efficiencies because of a lack of an IRIS incentive on connection charges.

Customers have limited bargaining power - the ‘large connection contract mechanism’ must be abandoned

10. We strongly disagree with the proposed ‘large connection contract mechanism’ proposed by the Commission. That mechanism would remove all charges for new connections above 10MW from the regime. Effectively unleashing a fully unregulated monopoly for these connection charges.
11. The Commission justifies this on the basis that large customers have ‘significant bargaining power’. There is no evidence to support this assertion. The reality is that it will give substantially more power to EDBs in an already lop-sided relationship.
12. Apart from some data centres, most large customers have little choice of where to locate their operations, given existing operations, supply chains, customer demand, and consent restrictions. Sorting a connection is usually the last issue to consider, and at that point a customer will have little bargaining power. In most cases the only choice a customer has is to take or leave the connection price offered by the EDB.
13. This is even more true for existing operations looking decarbonise who are effectively locked into a particular site. It is unclear if these connections would be covered under the proposed large connection contract mechanism, as they are often treated like new connections by EDBs rather than upgrades.
14. This mechanism will also be a road-block to renewable energy developments that are connected to distribution networks, as is common with solar farms and

some wind farms. The choice of site is largely driven by the quality of the resource (sun or wind) and minimising the environmental impact. Once a site is chosen there can be years of work to gain resource consent. This effectively locks in a yes/no decision on a particular site, giving an EDB significant power to extract excessive profits, and potentially stop the development altogether.

15. The result of the ‘large connection contract mechanism’ would be less electrification, less renewable generation and more emissions. It pulls in the opposite direction to government’s decarbonisation goals and must be immediately abandoned.

Connection costs often include wider network upgrades not related to the connecting customer

16. It is very common for an EDB to bundle connection costs and wider network upgrades, and charge all these costs to the connecting customer. Sometimes this is to create extra capacity for subsequent connections, in what is referred to as the first mover disadvantage (as the second mover can free ride on costs paid for by the first mover). Other times this is to strengthen the network for increased demand from existing users, or to replace aging assets. The four most common scenarios we see are explained in attachment 1.

17. As an example, our subsidiary Simply Energy has been working with a large food production company that is looking to increase electricity consumption to reduce their environmental impact. The initial quote from the EDB the upgraded connection included significant additional costs, such that it was less than half the cost to bypass the network and get a third party to connect directly to the GXP. Few end customers will have the locational luck, and flexibility to undertake this sort of arrangement, and will be stuck paying millions more than necessary, or choosing to not electrify.

18. Bundling of network upgrades with connection costs may be driven by the IRIS incentives. This is because overbuild paid for by connection costs are not subject to the IRIS disincentives, as it would be if the upgrades were included as a capital project. We can see two ways that this incentive may arise:

    a. Opportunistic unplanned upgrades – A new connection may lower the costs of other upgrades, which may present an opportunity to bring forward upgrades not currently planned in the capex allowances. If these costs were added as a capex project they would be subject to the IRIS disincentive rate. Whereas if these costs are bundled into the connection charge, the EDB faces no penalty.

    b. Creating more headroom in capex allowances – this may occur where an upgrade that could be bundled with a new connection is planned and included in the capex allowance, but the EDB considers that it is capex constrained. In this case the EDB may include the wider upgrade costs into the connection charge to create more headroom in the capex allowance for upgrades elsewhere in the network, without being subject to the IRIS disincentive.

19. If the customer chooses to go ahead with the connection regardless of these extra costs, then there is a substantial wealth transfer from the connecting party on one side and EDBs and other customers on the other. However, in many cases these extra costs mean that electrification projects are abandoned.

20. In theory the EDB should be incentivised to avoid this outcome, so that it can avoid the IRIS disincentives. However, it may be that some EDBs are happy to defer the wider upgrades until they are fully covered in future capex allowances, and they are indifferent to receiving the capital contribution for the costs of the connection itself.

Efficiency incentives are not working for connection costs

21. We are also concerned that there is no incentive for EDBs to seek out the lowest cost way to connect a customer. This is because the IRIS incentive does not apply to capital contributions. That means the EDB is not rewarded if they find a lower cost way of delivering a connection, and as a result we find many EDBs are unwilling to put in the effort to implement innovative approaches.

22. In one example Simply worked with a large process heat user on an electrification project and was able to reduce the cost per MW to less than a third of the initial quote from the EDB. Reaching this lower cost has taken years of negotiation from a team of experts. If New Zealand is to decarbonise at the pace expected there will not be the luxury of such protracted processes.

23. One area of particular concern is non-firmed connections, ie, connections where the customer agrees to connection with no redundancy, what the industry calls n level security, rather than the standard n-1 security provided to larger customers.

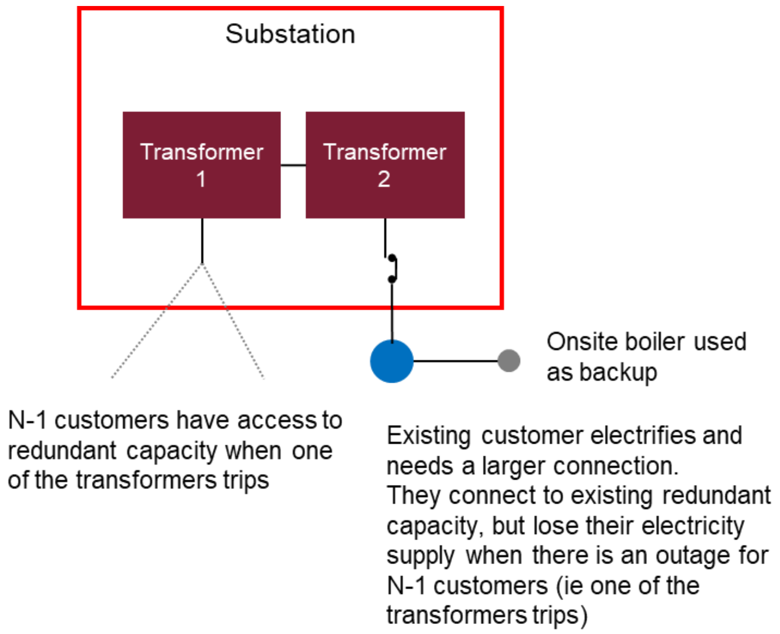
24. Many industrial process heat customers that we work with are happy to take a non-firmed connection as a step towards full electrification. They will retain their existing source of process heat, such as a gas or coal boiler to use as back-up if the network fails. Using on-site redundancy can often be substantially cheaper than network redundancy, particularly for process heat decarbonisation projects where on-site redundancy is an existing sunk cost.

25. A non-firmed connection can be millions of dollars cheaper than a firmed connection for a customer and is often the make or break between decarbonising or not. However, implementing a non-firmed connection can require a novel approach from the EDB, which can often be resisted.

26. For example, one way of implementing a non-firmed connection is to utilise existing spare capacity but switch off when that spare capacity is required to provide redundancy to other customers. A simplified example is shown in figure 1, where:

a. A substation with two transformers, to provide redundant capacity for an n-1 level of security for existing customers.
b. A non-firmed connection could be set up that utilises the spare redundant capacity.
c. In the event of an outage, the non-firmed connection is disconnected, and the redundant capacity is utilised the customers with n-1 level security to ensure continuous supply.

Figure 1: Simplified example of a non-firmed connection



27. We consider that this is an efficient use of assets. But it creates complexity for the EDB who must set up systems and processes to ensure that the redundant capacity is available for customers with n-1 level of security in the event of an outage. It is reasonable for the connecting party to pay these costs, and it may also be reasonable to reward EDBs for innovating, as would occur in workably competitive markets. However, currently many EDBs are unwilling to offer non-firmed connections at reasonable costs or include terms that make them commercially unworkable.

Creating better connection cost settings may require a joint project with the Electricity Authority

28. The Electricity Authority (EA) has recently begun a new project on distribution pricing which includes connection costs.[4] However, many of the issues covered above will require changes both to the Electricity Industry Participation Code and to the input methodologies. We therefore recommend that the EA and the Commission establish a joint project to consider the appropriate settings for connection costs.

29. We consider that there are broadly four areas that a joint EA and Commission project should focus on:

    a. Better information on connection costs:

        i. Requiring all EDBs to provide detailed information on quotes for connections so connecting parties can see what upgrades they are being charged for.[5]

        ii. It may also be appropriate to support this with changes to the Part 4 information disclosure requirements to track connection costs and any bundled in wider network upgrades at an aggregate level.

    b. Ensuring that a connecting party only pays the minimum cost required to make their connection.

        i. This would be a subsidy free rate to encourage connections where they are most efficient and charge connecting parties for the costs that they are responsible for, but no more.

        ii. This will need to be supported by a pricing methodology written into the Code.

        iii. It may also require changes to the cost allocation rules in the input methodologies. Other efficient upgrade work undertaken at the same time as a connection should be added to the RAB, and there may need to be new rules to ensure that these costs are appropriately allocated. For example, if there are economies of scope from doing other work at the same time as a connection, the benefits of this efficiency should be shared between parties. Also, a connection may require an existing asset to be replaced by a newer asset with higher capacity. This may provide a

[4] https://www.ea.govt.nz/projects/all/distribution-pricing/consultation/targeted-reform-of-distribution-pricing/

[5] We note that some EDBs such as Aurora already provide a full breakdown. We are asking for this to be more uniformly applied.

depreciation benefit to existing customers by lengthening the time until the asset needs to be replaced.

c. Support EDBs to undertake other upgrade work at the same time as a connection, if it is efficient to do so.

    i. It is often efficient to do other upgrades at the same time as a new connection is put in place. We want to make sure that EDBs are incentivised to combine connection projects and upgrade projects where it is in the long-term benefit of consumers.

    ii. For example, it may be appropriate to reimburse the IRIS disincentive in cases where anticipatory capex is taken up by a second mover.

d. Ensuring that EDBs offer non-firmed load where possible.

    i. A pricing methodology in the Code could help support non-firmed connections but will likely be insufficient without the right incentives backing it up.

    ii. It may be appropriate for the Commission to consider if an EDB can partially double-recover assets that are used twice. Taking the example in figure 1 above, it may be appropriate for an EDB to charge customers the full cost of an n-1 connection, but then allow for some (say 5-10%) of the cost of the redundant capacity to also be charged to the non-firmed connection. This appears consistent with how a workably competitive market would operate if a secondary use of an existing asset is found. It will mean that EDBs are incentivised to seek out non-firmed connections, which will provide a significant boost to process heat decarbonisation.

    iii. The Commission should also consider if voluntary non-firmed connections should be excluded from the measurement of the SAIDI and SAIFI quality measures.

Consumers must be protected from price shocks

Summary of price shock recommendations:

3. Ensure that the ‘revenue smoothing limit’ applies to price changes in the first year, ie price changes that occur between regulatory periods.
4. Apply the ‘revenue smoothing limit’ to all costs, including pass-through costs.
5. Retain transmission charges in the ‘revenue smoothing limit’ for EDBs but consider if Transpower should have more obligations to share the burden of smoothing prices.
6. Consider the impact on consumers of cumulative price increases year-on-year

30. As indicated by the Commission, there is likely to be a substantial uplift in the allowable revenue at the next electricity lines price resets. It is likely there will be a significant jump in the WACC rate and sufficient allowances so that the lines companies can strengthen their networks to support decarbonisation.
31. We agree with the Commission that it will be particularly important to protect consumers from price shocks during this period. These increased costs may be felt more by more vulnerable households. Households with more means are likely to have greater capacity to shift load, use alternative energy sources like solar panels, and buy an EV to reduce their total energy bill. So even a 10% limit on revenue increases could result in a much more significant increase for those who can afford it least.
32. In deciding how to smooth costs over time, the Commission should apply its economic principle of allocating risk to the party best placed to manage it. Lines companies will have a much stronger facility to spread costs over time than will end consumers.

The existing price shock protections are not working

33. The price shock mechanisms the Commission has put in place are not having the desired effect. We have recently seen a price increase from First Gas for 2023/24 of over 30%, despite the 10% price shock limit. Similarly last year Vector gas had an almost 20% price increase for the 2022/23 year, significantly higher than the 7.7% revenue increase allowed by the Commission. Not only have these increases resulted in substantial price rises for end customers, but notification about them has also often come through so late that it has been a shock in every sense of the word.

34. We are deeply concerned that the same outcome may occur in the next electricity lines price paths. This would cause a significant shock to consumers and could seriously undermine confidence in the market and regulatory settings.

35. The recent price shocks look to have been largely caused by a mixture of forecasting error and including too many costs as ‘pass-throughs’ not subject to the price shock limits.

    a. The large increase in Vector’s 2022/23 prices appears to be largely a result of a forecast error where the Commission over-estimated 2021/22 revenues, so set a starting price for the 2022 DPP at a level that caused a price shock. Forecasting errors are a fact of life, but it is inappropriate for consumers to bear the risk of these errors. We therefore propose that the ‘revenue smoothing limit’ proposed in the Draft Decision applies equally to the first year of a price path as it does to future years, ie it applies to price changes between regulatory periods.

    b. The large price shock in First Gas’ 2023/34 prices appears to be because there are an increasing number of costs being included as pass-throughs and therefore not subject to the price shock limits. We are unsure of the logic for this. Regulated businesses will be better placed to manage input price volatility than end consumers. We propose that all recoverable and pass-through costs are subject to the price shock limits.

Pass-through of transmission charges

36. In the draft decision the Commission proposes to allow EDBs to fully pass through transmission charges, and not include these costs in the EDBs price shock revenue increase limits. This is in response to concerns from EDBs about the impact transmission price changes could have on their ability to finance necessary investments.

37. While we appreciate the concerns from the EDBs, this proposal takes little to no consideration of the impact this could have on consumers. We consider that lines companies will be better placed to manage price volatility than will end consumers.

38. A more consumer centric approach would be to retain the current obligations on EDBs but put greater obligations on Transpower to share some of the burden of smoothing prices for consumers. For example, it may be appropriate to set a ‘revenue smoothing limit’ on Transpower that applies at a regional level, and better accounts for the volatility from the yearly re-openers.

Cumulative effects of price changes

39. The Commission should also consider the cumulative effect of year-on-year price increases. For example, the Commission has in the past set a price shock

threshold of 10%+CPI, several years of price increases of this magnitude would constitute a price shock for most consumers.

40. The Commission should consider more sophisticated mechanisms to avoid a continuous march up of prices.

The WACC percentile remains too high

Summary of WACC percentile recommendations:

7. We recommend that the Commission uses the 60th percentile of the WACC for setting the electricity lines revenue limits. This better reflects the weight of evidence showing that the percentile should be materially lower than its current level.

41. The Commission has undertaken a through refresh of the analysis underlying the WACC percentile. This analysis can never precisely identify the uplift required to best serve the interests of consumers, but it can give a rough range and indicate where in that range the uplift should lie.

42. All of the updated analysis, new evidence, and evolved regulatory settings point to the current 67th percentile WACC being too high.

    a. The lower bound of the loss model has shifted from the 60th percentile in the 2014 calculation to the 55th percentile in the updated calculations

    b. Experience both overseas and for related sector's in New Zealand has shown that applying the 50th percentile has not caused the theoretical risk of underinvestment.

    c. Various incentive mechanisms have been introduced since 2014, including the quality incentive and the IRIS.

    d. The Commission has undertaken more enforcement action, and improved summary and analysis, providing a more credible threat to the temptation to underinvest.

43. Further to this evidence, the Commission should also replicate the RAB multiples analysis undertaken in 2014. While not a precise measure it provides a clear signal when the regime is being too generous. A rough scan shows that commercial valuations continue to be well above the RAB valuation:

a. In 2015 Vector sold its gas transmission business to First Gas for $952.5m[6], compared to a RAB value in the year beginning July 2015 of $503.2m, suggesting a RAB multiple of 1.89.

b. In 2022 Eastland sold its electricity distribution business to First Gas for $260m[7], compared to a RAB value of $188m at 21 March 2022, suggesting a RAB multiple of 1.38.

44. We do not consider that a 2 percentile point reduction is proportionate to this weight of evidence.

45. We recommend that the Commission uses the 60th percentile of the WACC for setting the electricity lines revenue limits. This is still comfortably within the range of the loss analysis, and better reflects the weight of evidence showing that the percentile should be materially lower than its current level.

We support the indexation of all lines assets

Summary of indexation recommendations:

8. Retain the draft decision not to un-index EDBs RAB
9. Retain the draft decision to index Transpower's RAB from the start of RCP4

46. We fully support the Commission's draft decision on RAB indexation for EDBs and Transpower.

47. The request from EDBs to remove indexation of the RAB is a crude measure to bring forward cash-flows at a time when lines charges will already be rising sharply for end users. The Commission was right to deny this request and must hold firm against the likely mountain of pages that EDBs will write on the topic in their submissions.

48. We also support introducing indexation for Transpower's RAB. This brings them into line with other regulated businesses, and a more traditional accounting approach. The timing will also help soften the sharp price rises expected in the next RCP.

[6] https://www.nzherald.co.nz/business/vector-sells-gas-business-for-952m/LQV5DXAG22FQJYNNYXQYSDPBEQ/

[7] https://www.eastland.nz/2022/11/22/eastland-group-and-shareholder-trust-tairawhiti-announce-sale-of-eastland-network-to-firstgas-group-owned-by-igneo-infrastructure-partners-for-260-million/

49. We expect that this change will be a substantial project for Transpower, but delaying it will not lessen the work involved, and will only prolong an inconsistent treatment. There must be a very high bar reached before delaying the implementation of this change.

Any innovation allowances must focus on additionality

Summary of innovation allowance recommendations:

10. Require that applications for the 'innovation and non-traditional solutions allowance' must
    a. prove additionality, ie, that the work would not have occurred without the allowance;
    b. demonstrate that the existing incentives are insufficient to reward the innovation or non-traditional solution;
    c. not apply to potentially competitive services; and
    d. not apply when a project requires support to multiple parties to be successful.

50. The Commission proposes to expand the scope of the innovation project allowance into a new 'innovation and non-traditional solutions allowance'. The new allowance would give greater scope for how the allowance is set at each price setting.

51. This allowance plays the same role as a government funded innovation fund. In a recent inquiry the Productivity Commission considered these innovation funds in detail.[8] It found that one of the key risks of these funds is that they can just fund 'business as usual' activity. They propose a strict focus on additionality, where criteria to gain access to the fund must demonstrate that the activity would not have occurred without the funding.

52. We consider that the principle of additionality is so fundamental to innovation allowances that it should be written into the input methodologies. Without this criterion there is a substantial risk that any extra allowance is not value for money for consumers.

53. The assessment of additionality must also consider the other incentives already on offer, such as the IRIS. In most cases a lines company will already be rewarded for incurring costs for non-traditional solutions or innovation if these investments mean they can 'beat' the forecast allowances. For example,

[8] https://www.productivity.govt.nz/inquiries/frontier-firms/final-report/

innovations that allow for more non-network solutions may reduce network upgrade costs, resulting in an IRIS incentive payment.

54. However, there may be some cases where the existing incentives do not apply. For example, in cases where there is significant uncertainty about the success of the innovation, but substantial upside to consumers if it is successful. Another example may be where there is a significant lag between innovation costs and benefits, and therefore the benefits become incorporated into opex and capex allowances, which means that the IRIS incentive no longer applies.

55. The ‘innovation and non-traditional solutions allowance’ must be laser focussed on these exceptions to avoid padding the revenue allowances of the lines companies and providing no benefits to consumers.

56. We are also deeply concerned that this allowance could be used to give lines companies a ‘leg up’ in potentially competitive services like non-network solutions. By its nature this fund is only available to lines companies, so there is no competitive tendering for the best approach. Similarly, in some cases funding for pilots would need to be provided to multiple parties to be successful, not solely the lines company. For example, innovation in demand response spans across customers, demand response intermediaries, and the lines companies. Limiting support to only lines companies will distort the development of this market.

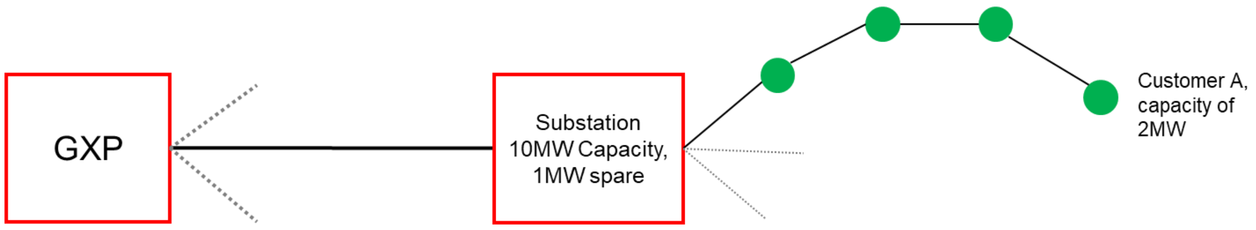
57. To avoid competitive distortions, the ‘innovation and non-traditional solutions’ allowance should exclude projects that could be implemented by other parties or requires wider support than just to the lines company. For example, funding for non-network solutions must focus on building the market / product such that it allows third parties to participate, and stop short of funding the solutions themselves.

58. While outside of the scope of the Commerce Commission, we consider that, a dedicated government innovation grant should be established to support wider market innovations. This grant should be open to all parties, and will often require support to multiple participants, not just the lines company.

Attachment 1: Stylistic connection scenarios

In this attachment we consider four stylistic scenarios of the most common issues we see when customers are charged for wider network upgrades. Each scenario identifies one issue in isolation for simplicity. In reality often many of these issues are combined together.

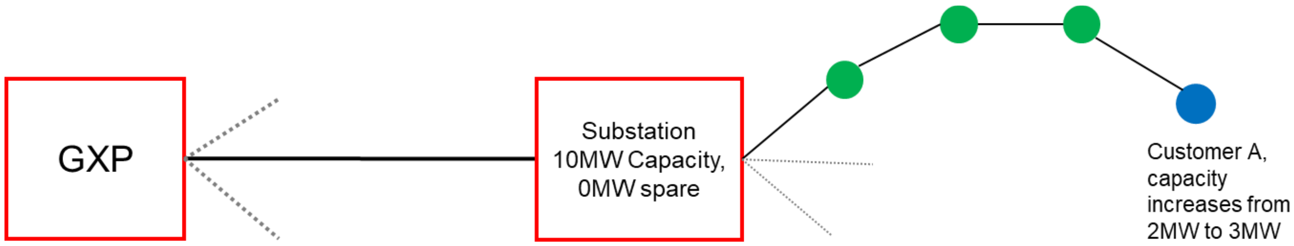
Status prior to new connection



Description:

- Customer A has a total capacity of 2MW
- The substation they connect to has a total capacity of 10MW, with 1MW spare (not used for any network purposes or any connection)

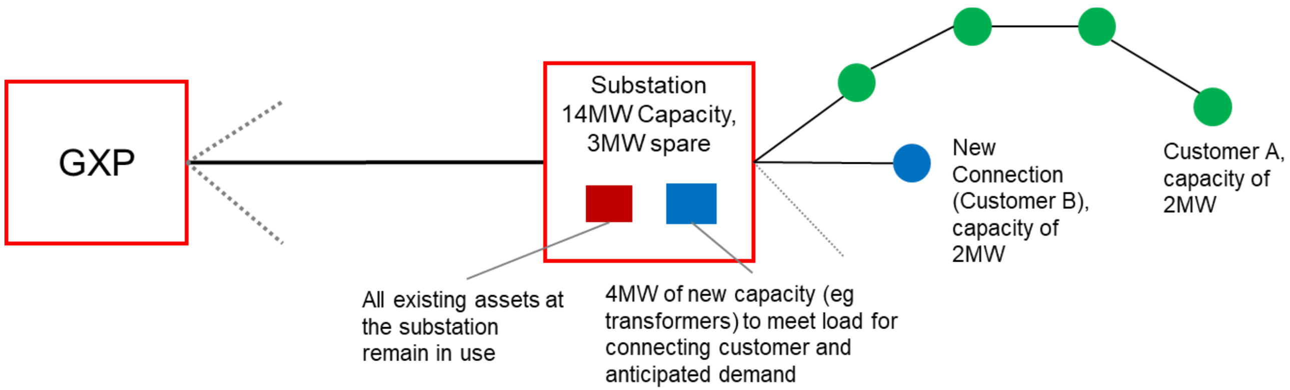
Scenario 1: New Connection utilising existing assets



Description:

- Customer A increases capacity from 2MW to 3MW
- The customer pays for upgrades to direct assets (lines, circuit breakers, etc), but has no indirect connection costs as they are utilizing existing spare capacity.
- We have no concerns with this scenario, it is included as the simplest case, but is in practice very rare.

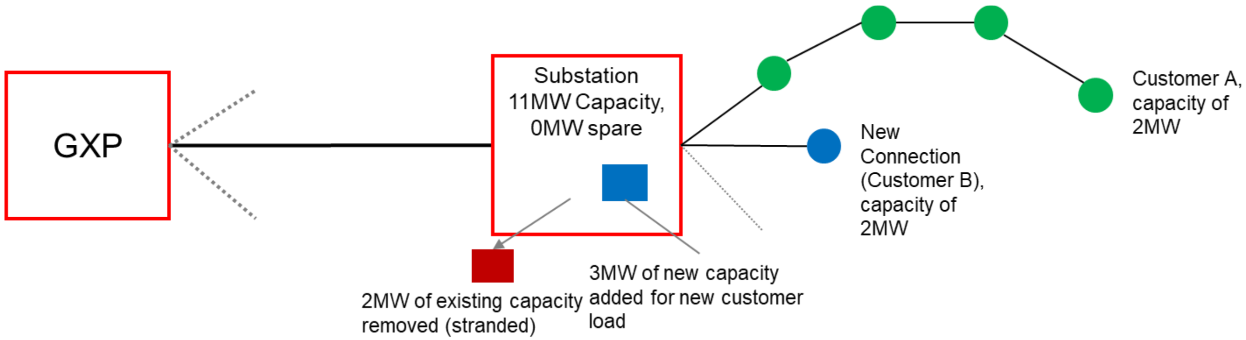
Scenario 2: Overbuild for second movers



Description:

- A new customer is added to the network demanding total capacity of 2MW.
- This exceeds the spare capacity at the substation, so the new customer must pay for the upgrade costs. In this scenario the network company can add new assets to meet the load (does not have to replace an existing assets). However, the network company decides to add in extra capacity to provide more headroom for anticipated future demand.
- Often all these upgrade costs fall on the connecting customer (customer B), including the overbuild for future entrants. Some EDBs have discussed a regime where a subsequent entrant reimburses the first mover for the extra costs once they are connected. However, even under this arrangement the first mover is taking significant extra costs and risks.

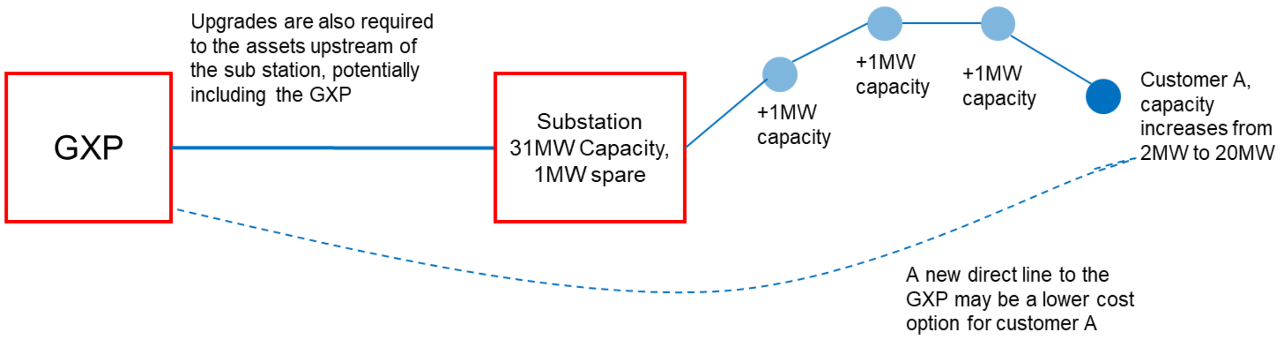
Scenario 3: Asset upgrade (stranding)



Description

- As with scenario 2, a new customer is added to the network demanding total capacity of 2MW.
- In this scenario the network company must replace existing assets at the substation with new assets with a higher capacity. Eg replace an old 2MW transformer with a 3MW transformer.
- Often all upgrade costs fall on the new customer. In this case it means paying for a new 3MW transformer, even though the capacity they will use will only be 2MW.
- If the upgraded assets are newer, existing customers gain a depreciation benefit as it will be longer until the assets need to be upgraded.

Scenario 4: Existing customer increases demand triggering a wider upgrade of the network



Description

- Customer A increases demand from 2MW to 20MW to electrify process heat.
- In this case the connecting customer (customer A) is often charged for:
    - The 18MW of extra capacity required at the substation for their connection
    - A further 3MW of capacity to upgrade other customers capacity (assets at the substation, but may also include higher spec lines)
    - Upgrades upstream of the substation, potentially including the GXP.
- In these cases we often find that the costs of a new direct line to the customer from the GXP is lower cost than the wider upgrade to the network. This may not be the most efficient upgrade for the network, but it is inappropriate for the additional costs of wider upgrades to fall on the connecting customer. We consider that in this scenario costs need to be allocated appropriately with the connecting customer paying the minimum cost to connect (potentially the cost to build a new connection to the GXP), and the remaining 'wider upgrade costs' allocated to the RAB.