Section 10: Connecting to the national grid

This section sets out our understanding of issues relating to transmission connections to support growth in renewable electricity and the transition to a low emissions economy.

It seeks your views on options to address:

- the first mover disadvantage
- gaps in publicly available and independent information, and
- a lack of information sharing for coordinated investment.

What is the problem?

We are moving into a period of more customer-driven transmission investment, with increased renewable generation and process heat demand connecting to the grid. The challenge is to enable this while managing opposing risks of under or over-investing in the national grid.

Additionally, there are long lead times for major new and upgraded transmission assets relative to lead times for new generation or demand. Issues with cost allocation and risk associated with new transmission lines may slow or hold up the deployment and uptake of renewable electricity generation, risking delays in decarbonisation. There are also coordination challenges where investments involve multiple parties.

Recent modelling by the ICCC[111] indicates that about 10 to 15 transmission upgrades could be needed by 2035 to support decarbonisation. The upgrades common across all the scenarios modelled include a few known "pinch points" and a small number where new generation is built in parts of the grid with limited transmission capacity.[112]

Enabling new connections

Traditionally, investment in new and upgraded transmission lines has been driven by steady or predictable growth in electricity demand (e.g. new lines to Auckland), and has been part of system wide investment in interconnection assets with a relatively low risk of stranding or underutilisation.

In anticipation of more renewable generation and electrification, Transpower recently commenced a complementary project called "**Enabling New Connections**" to consider what it (and the industry) needs to do to enable the new connections required. It will consider how the system and market could evolve over the coming decades, barriers to connection, information needs and process, and potential constraints in terms of people capability and capacity.

In addition, new assets would be needed to connect new generation and process heat plants to the grid. Transpower's recently commenced project "Enabling new connections" (refer text box) seeks to understand how it and others can meet this challenge.

[111] New generation included in this modelling is based on details of consented and otherwise potential new projects that are publicly available, although in scenarios with the largest number of wind farms, some are moved to reduce correlations in output/manage intermittency.
[112] The modelling also indicates an upgrade to the HVDC link is needed under the 'accelerated electrification' scenario, and possibly under the 'business as usual' and '100% renewable electricity' scenarios.

The ICCC heard that regulatory hurdles relating to the connection of boilers to transmission and distribution networks can play a significant role in fuel switching decisions. Further:

> *"If uncertainty and regulatory hurdles result in new investments in fossil fuel technologies instead, this would lock New Zealand into high-emissions technology for decades to come and would make it much more challenging to meet New Zealand's emissions reductions targets. Policy change is needed."*[113]

Understanding how the costs of transmission assets are recovered and who bears the risk of underutilisation helps with understanding the issues with investing in transmission assets to connect to the grid.

The Commerce Commission determines how much revenue Transpower can recover each year from assets in its regulated asset base (RAB). The Transmission Pricing Methodology (TPM) determines how charges are calculated for RAB assets and who pays for them. The EA's guidelines for the development of the TPM are being reviewed.[114] For assets outside of the RAB, cost recovery arrangements are established in contracts with Transpower.

The three types of transmission asset (interconnection, connection, or HVDC asset) and cost recovery mechanisms are described below.

Connection assets

The challenges addressed in this consultation are most relevant to connection assets, which are typically dedicated to one customer such as a generator or grid-connected large user. Any costs Transpower incurs ahead of a decision to build a new connection asset are an upfront cost to the customer seeking to connect. Once established, the costs of connection assets (capital and operating) are paid for by connected parties.

Charges for connection assets are either determined under the TPM or in a contract with Transpower. Under the current TPM, the ongoing charge for each connection asset is calculated based on average depreciation of all the connection assets in the RAB.

In its recent consultation on transmission pricing, the EA proposed largely retaining this aspect of the TPM as it considers it provides parties with incentives to take connection costs into account in their own investment activity and operations, and to seek the connection option (or an alternative to connection) that most cost-effectively meets their needs.

Connection assets come with a higher risk of becoming stranded assets, for example if the dedicated customer shuts down. There is also the issue of 'first mover disadvantage', where the first customer (generator or large user) incurs the full costs on a larger asset and bears the risk of subsequent customers not eventuating (this is described more below).

Interconnection assets

Interconnection assets form the core part of the grid[115] and generally sit in the RAB. Interconnection charges cover the (shared and common service) costs, which currently are shared between all *demand* customers connected to the system.[116] This means that there is little incentive for

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[113] Page 90, *Accelerated Electrification*, ICCC

[114] The current TPM is considered to encourage inefficient use of and investment in the transmission grid. The proposed changes to TPM guidelines aim to better align the charges transmission users pay for new investments with the costs of those investments.

[115] They are "looped" assets, where the line loops through the service area and returns to the original point

[116] This is called the Regional Coincident Peak Demand (RCPD) charge and recovers both capital and operating costs over the lifetime of the asset (e.g. 30 to 40 years). It is a "postage stamp" type charge, where connected

information sharing between parties, and for participation in the process, and scrutiny of, Transpower's proposals to invest in interconnection assets.

In its recent consultation, the EA proposed that the costs of interconnection assets are instead allocated based on how customers benefit from them. This will create an incentive for customers to participate in the approval process as they will pay a larger portion of the cost of a new investment they benefit from (instead of simply paying a small share of all costs).

HVDC assets

HVDC assets link the South and North Islands and are currently paid for by South Island generators. The EA has proposed that the HVDC charge be replaced with benefits-based and residual charges. This may create a more favourable investment climate for South Island based renewable generation investments, depending on how any new charges compare to the current HVDC charge. The issues outlined below are not relevant to HVDC assets, so they are not discussed further.

Grid investments

Transpower is a State Owned Enterprise (SOE) and is required to operate as a commercial business.[117] Because it has a regulated income, it generally avoids taking undue risk with grid investments, preferring certainty that its costs will be recoverable. However, there is some latitude in the level of risk Transpower and its shareholder (the Crown) is willing to accept. A higher level of risk may be acceptable in the context of the need to transition to a low emissions economy.

There are two ways that investments in the grid can occur – either by approval from the Commerce Commission, or through a contract between Transpower and one or more counterparties.[118]

Investments in the Regulated Asset Base (RAB)

Investments approved by the Commerce Commission become part of Transpower's RAB. Transpower can continue to recover the cost of assets in its RAB under the TPM even if they become stranded or are underutilised. While this takes an element of risk away from Transpower, it is a cost to all connected customers, which is ultimately passed on to electricity consumers.

Investments in transmission that are expected to cost over $20 million must be individually approved by the Commerce Commission using criteria set out in Transpower's 'Capital Expenditure Input Methodology' (Capex IM).[119] The Commerce Commission must consider MBIE's Electricity Demand and Generation Scenarios (EDGS) in the approval process.

An investment needed for the deployment and/or uptake of renewables may not get approval if there is too much uncertainty (risk) regarding its utilisation (and therefore its costs and benefits).

Transpower pays for investments that are expected to cost less than $20 million from a fungible envelope of 'base expenditure' that is approved by the Commerce Commission.[120] This does not

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customers pay the same rate ($109 in 2019/20) per kW it contributes to the top 100 peak demand periods in the region in the previous year) no matter where they are in the country.

117 Under the State-Owned Enterprises Act 1986.

118 The counterparty does not need to be a transmission customer.

119 *Transpower Capital Expenditure Input Methodology Determination 2012,* made under Part 4 of the Commerce Act 1986.

120 Base expenditure is set for each five year regulatory period. Transpower can apply to have the limit increased for certain asset replacement and for refurbishment projects over $20 million, and it has the freedom to reallocate/reprioritise spending on any project within the overall funding envelope.

fully de-risk Transpower from overspending as there are efficiency incentives in place for cost management.[121]

Contracted assets

New and upgraded transmission assets[122] commissioned under a contract do not require Commerce Commission approval and sit outside of Transpower's RAB. Cost sharing arrangements will be set out in the contract. Such contracts are a potential option for new large users or large generators requiring a connection or significant upgrade, but have sometimes proved difficult to arrange when they involve multiple parties.

There can still be issues with cost allocation when assets outside of the RAB, and with who bears the risk of stranded or underutilised assets – connected customers under contract (generators, distributors, and directly connected large users), or Transpower (as a cost of business that is passed on to all connected customers).

A business considering new generation or electrification may be deterred from investing if it faces (or perceives it will face) too much risk about the future cost recovery of the associated transmission asset. For example, it could anticipate that its share of the cost will reduce over time if others connect to the asset in the future, but there is always a risk that subsequent customers do not eventuate leaving the asset underutilised. A business that decides to invest is incentivised to have the asset sized to its needs, not to a capacity that could serve future and uncertain demand.[123]

Transpower has indicated that a common 'sticking point' in negotiations is that the budgets and project plans it provides for new connections are indicative[124] and the costs are uncapped. This is because Transpower seeks to avoid the risk of the new connection costing more than it can recover (construction cost over-runs cannot be recovered through TPM charges).[125]

In terms of delivery timeframes, Transpower's reluctance to bind itself reflects delays that can be caused by third-parties due to factors such as the need to acquire land or easements, resource consents and procure equipment. Issues with obtaining resource consents are covered in section 7 of this document: *Enabling renewables uptake under the Resource Management Act 1991.*

Investment timing and commitments of each party inevitably vary, not least due to factors set out above. In addition, devising an equitable cost sharing arrangement between counterparties can be difficult.

[121] The extent to which Transpower fully recovers the actual spend depends on the extent to which there are cost over-runs for individual projects over $20m, or for the base capex allowance as a whole.
[122] Typically for connection assets, but could be for interconnection assets if there is a willing counterparty or parties.
[123] Note that an asset may initially appear to be 'over-capacity' but could be optimal over the lifetime of the investment, and the first mover may benefit from capacity larger than its own needs, particularly relative to an alternative of not being connected at all. It is therefore not always clear cut whether the first mover should not be expected to make a contribution to the temporary 'over-capacity'.
[124] With rare exceptions.
[125] Under the Capex IM, all assets funded through contracts must go into the RAB at a value of zero.

The first mover disadvantage

What is the problem?

Under the current arrangements, the first party to a new connection covers the full cost of the asset (albeit spread out across the lifetime of the asset) until another party connects and pays its share going forward. This can:

- lead to suboptimal transmission infrastructure investments, which favour existing infrastructure over new infrastructure, or
- disincentivise investment in higher capacity connections by the initial developer (generator or large user) due to the risk of being the only connected customer, paying for capacity and overbuild that it does not need or utilise.

The barriers associated with new investment could also be creating a possible bias towards incremental generation growth in regions already well-served by transmission facilities, even if there are more economic generation options in other regions.

Ideally, to take advantage of economies of scale, new transmission assets should be sized to serve the potential supply and demand growth in a region. Under current arrangements connection assets are more likely to be sized for the first mover, or possibly not even eventuate. Sizing for the first mover may also lead to consenting issues for subsequent parties connecting if a line needs to be incrementally changed to accommodate extra capacity.

For example, there are multiple potential wind generation sites in the Wairarapa with a combined capacity of up to one gigawatt, but the region does not have a transmission connection that could support these. No developer has committed to a project in this area, though in the past several potential developers spent considerable time and resource trying to negotiate an amicable cost sharing arrangement. In the absence of such an agreement, the first mover faces a higher per-unit cost on new generation due to the initial transmission investment, potentially for years to come until other wind farms are progressively developed and especially if a large connection is built.[126]

Such barriers could affect the future development of sufficient renewable electricity generation to support the transition to a low emissions energy sector, and potentially limit more effective regional development.

What are the options?

Three options are being considered for adjusting the cost and risk allocation for new and upgraded connections that could address the issues outlined above. The first two options seek to improve investment decisions while balancing the need to align risks with the benefit arising from the new assets. The third option would lessen the incentives to overbuild the transmission grid and could increase electricity costs, so is the least preferred option.

Some of the options may require the Commerce Commission to consult on potential amendments to Transpower's Capex IM, or other input methodologies that apply.

Other options were identified, including establishing a special purpose Crown company, mechanisms to reserve capacity, and reducing asset values under the TPM. However, these are not proposed for further consideration due to: the perceived risk of unintended consequences (high relative to the size of the problem), potential issues with competition law, and in some cases potential incompatibility with consultation underway on the guidelines for the TPM.

[126] Further discussion of this example is in the Productivity Commission's low emissions economy report, August 2018 (page 396 on).

Option 10.1	Encourage Transpower to include the economic benefits of climate change mitigation in applications for Commerce Commission approval of projects expected to cost over $20m. This would be through the inclusion of the (avoided) emissions price cost incurred by consumers calculated on a consistent basis. Guidance or direction about the emissions price and trajectory would be needed to support this option.

This option would apply to transmission investments over $20 million that need to pass the 'market benefit test' set out in Transpower's Capex IM. This is a test developed and applied by the Commerce Commission. It is designed to ensure there is a robust business case to make the proposed investment based on future needs, and it is intended to avoid the risk of building significant infrastructure in places where there will be limited demand.

The market benefit test can already include the economic benefits of climate change mitigation.[127] Transpower's current practice is to include the emissions cost incurred by generators through applying a forecast emissions (ETS) price as a cost to carbon-emitting generators in its applications. A more holistic approach could be taken to include the benefits of consequential emissions reductions elsewhere, such as through increased electrification and reduced fossil-fuel use.

Fully quantifying the economic benefit of any avoided ETS costs[128] in applications could bring forward investments in transmission assets that enable new generation or electrification.[129] This may negate the need for first movers (and other parties) to establish a connection asset through negotiation. It also shifts cost and utilisation risk from the first mover to Transpower. Once built , the first mover will face higher (per unit) connection charges under the TPM, but it will not face the upfront cost, not bear the risk of underutilisation, as it would under a contracted asset.

Ensuring that the economic benefits of climate change mitigation are routinely included would support the business case for investment in new renewable electricity transmission infrastructure. Options to achieve this range from the Government providing direction (e.g. in an Owner's Letter of Expectation), through to mandating how Transpower should account for emissions goals. For consistency, implementing this option would require government direction or guidance about the emissions price and trajectory that should be assumed in the analysis (e.g. which future emissions price path should be used).

Depending on the proposal, including avoided ETS costs could increase the benefits enough to result in it passing the market benefits test. It may not capture the full externality cost of emissions, but will to the extent that the policy settings for the NZ-ETS allocate the cost of emissions to electricity market participants. As noted earlier, the NZ-ETS settings are currently under review.

Depending on how the costs are allocated, in some cases Transpower may not recoup all of the revenue it requires from a particular asset, and any shortfall would be met by electricity consumers (or the Crown, as per option 10.3 below).

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[127] Through the inclusion of avoided emissions costs to the extent that they are (or are expected to be) internal to the electricity market), as per the Schedule D, clause D4(1)(j)(ii) of Transpower's capital expenditure input methodology determination (as at 1 June 2018).

[128] This would require working out how to include reduced fuel burn from thermal generation and/or electrification

[129] Note that the market benefits test will consider lifecycle net benefits and expected demand to connect over the lifetime of the investment, so connection projects serving multiple parties might pass the investment test without the need for ETS benefits to be taken into account, particularly if those benefits are not material to the investment choice.

Option 10.2	Put in place additional mechanisms to support or encourage, Transpower, first movers and subsequent customers to agree to alternative forms of cost sharing arrangements by contract.

This option draws on the ability for Transpower and connecting parties to undertake commercial negotiation to agree how the cost and risk of a new connection is shared between them, and potentially other parties in future. It is most suited to connection assets with only one or two counterparties.[130]

This can already happen if subsequent customers agree (by contract) to contribute to the charges the first mover (now incumbent) is paying under its contract with Transpower. However, as there is currently no obligation on parties that subsequently connect to contribute, there is little incentive for them to agree to a cost sharing arrangement.

One option is to introduce a new charge through the Code (or TPM) for customers that subsequently connect to a contracted asset that they have not contributed to the funding of. The charge could provide a rebate to charges already paid by the first mover or off-set the amount recoverable from all customers on the connection.

Other options

- introducing a requirement (e.g. in the Code) that a second or subsequent customer cannot connect unless it enters into a cost sharing arrangement with the first mover, or make some sort of contribution to the cost of the asset to date. For this to work effectively, it may require a fall-back mediation process to be established to facilitate agreements.
- transferring contracted connection assets that end up serving more than one party to the RAB with annual payments rebated to the first mover.

Note that the cost to the customer of investments under contracted arrangements can be higher than the cost of investments that end up in Transpower's RAB due to customer credit risk.[131]

Option 10.3	Shift some of the cost and risk allocation for new and upgraded connections from the first mover through mechanisms within the Commerce Commission's regulatory scope, with the Crown accepting some of the financial risk. Two identified ways to achieve this are[132]:	
	10.3.1	Optimise asset valuations under the Commerce Commission's regime in circumstances where demand is lower than originally anticipated because expected (subsequent) customers do not eventuate.
	10.3.2	Provide for Transpower to build larger capacity connection asset or a configuration that allows for growth, but only recover full costs once asset is fully utilised, with the Crown covering risk of revenue shortfall.

[130] Interconnection assets can be established by contract (instead of through the Grid Investment Test), but this is unlikely due to their high value and the many parties that are involved.
[131] The credit risk is created as charges under a contract are only enforceable against the counterparties to the contract, so if a party defaults, Transpower cannot recover the cost from any other party. By comparison, if a customer defaults on paying its TPM charges on assets in the RAB, Transpower can recover the under-payment from other customers in subsequent years. The extent to which this increases the cost depends on how the risk-adjusted returns in contract compare to the cost of capital applied to the RAB, and it is possible that the costs to individual customers could be lower under contracted arrangements.
[132] Both would require the current input methodologies that apply to Transpower to be amended.

This option aims to provide Transpower more flexibility in how the costs of assets are recovered over time, and allow it to shift more of the financial risk away from connection customers (ultimately to the Crown and therefore taxpayers).

It is difficult to assess the relative merits of this option. There is limited evidence both about the magnitude of the first mover problem and the potential effectiveness of the likely significant shift in cost and risk allocation that would be involved. This is therefore not a preferred option further consideration, but included for feedback to gather information and evidence to inform an assessment.

Under option 10.3.1, Transpower's assets could be partially written off, have their lifetimes extended, or there could be changes made to depreciation rates or methodologies. Transpower would then recover lower transmission charges (and therefore lower revenue) from the connecting customer in respect of the connection asset.

Under option 10.3.2, Transpower would get approval to build a connection asset that then becomes part of its RAB (rather than build it under contract). It could then opt to build the asset to a higher capacity, but not put the increased value of that asset into its RAB. While the asset would sit in its balance sheet, it would gradually appraise its potential value each year based on the likelihood of it being fully utilised.

Under either option, any shortfall in Transpower's revenue that results would need to be covered by the Crown through either accepting a lower return, or through a loan mechanism with the potential for it to be written off.[133] For example, the Crown could provide Transpower a loan for specific transmission assets that could be paid back as more customers connect. This is illustrated in the diagram below that sets out the types of asset and how they could be funded.

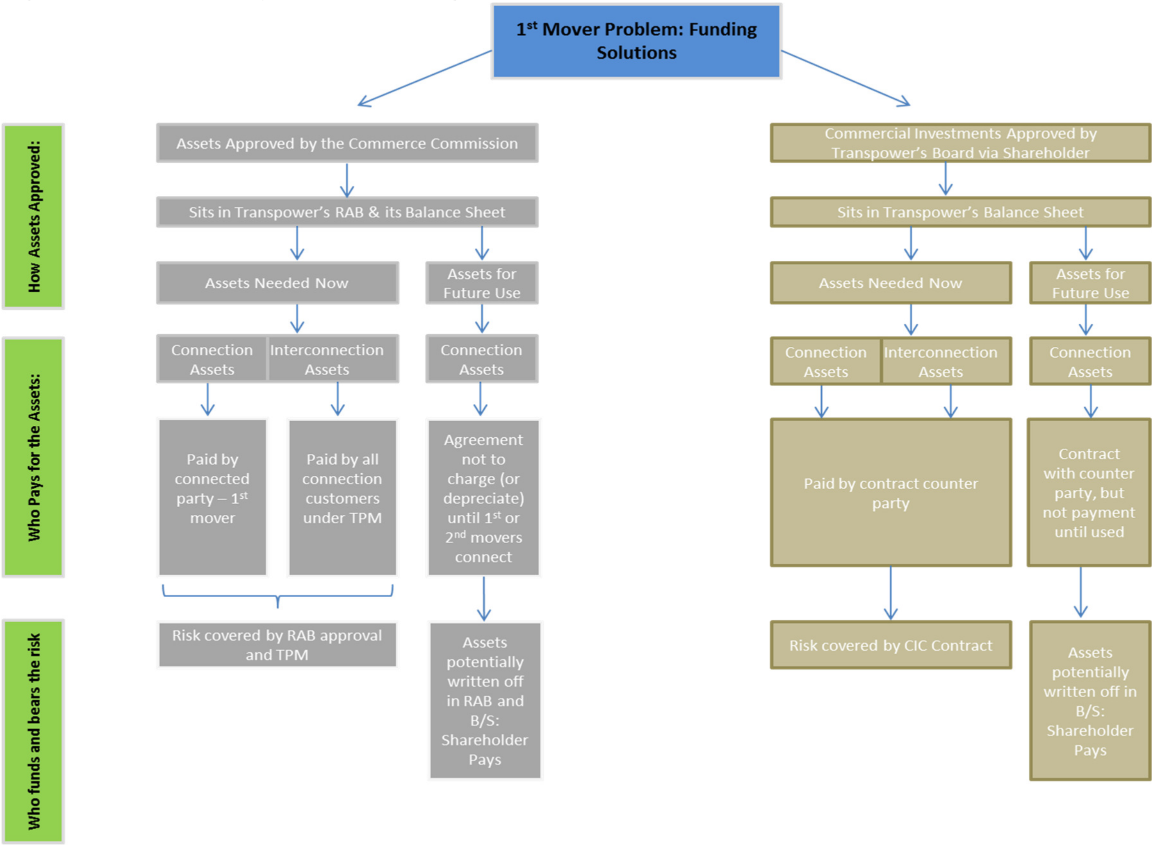
These options would lessen the incentives on Transpower to not overbuild transmission assets and (all else being equal) could increase electricity costs.

Questions

Q10.1	Which option or combination of options proposed, if any, would be most likely to address the first mover disadvantage?
Q10.2	What do you see as the disadvantages or risks with these options to address the first mover disadvantage?
Q10.3	Would introducing a requirement, or new charge, for subsequent customers to contribute to costs already incurred by the first mover create any perverse incentives?
Q10.4	Are there any additional options that should be considered?

[133] As it would reduce Transpower's dividends (as it impacts on its operating balance before gains and losses (OBEGAL)).

Figure 3: First mover problem funding



Source: Ministry of Business, Innovation and Employment

Gaps in publicly available and independent information

What is the problem?

There is limited public information and access to independent data on where new generation is likely to be built, or where large demand is likely to be added. In addition, there are various agencies, regulations and approval processes that can be complex to navigate, especially for a non-electricity business (e.g. a process heat user). As a result, investors and Transpower can lack sufficient or key information for robust and timely decision making.

There is an inherent tension in the provision of information regarding potential investments in generation. Developers will undertake significant investment in data before making investment decisions and see benefit in holding intellectual property (IP) on their new generation options. On the other hand, Transpower requires good information to undertake proactive investment in planning, and independent data sources could add credibility to its investment decision making.

Current public information sources include:

- the EA's existing database on potential or planned generation (based on public information)
- MBIE's and the ICCC's modelling results that show new generation options
- Transpower's planning documents, developer / investor public statements, and
- process heat users' public statements, and stated emissions reduction plans.

Many of these sources are not systematic and only have a limited shelf life. There is a potential role for government to provide more independent public data to fill these information gaps with the aim of:

- Aiding proactive transmission investment, opening up new areas to generation investment and electrification, and better aligning construction timing
- Providing some certainty to investors regarding the availability of transmission capacity, and
- Building understanding of the process for upgrades and new connections to the grid.

What are the options?

There are a range of options to improve information for generation and electrification investors, some of which are set out below for feedback. The options are presented at a high level in order to seek feedback on whether they merit further investigation.

Options involving the mandatory provision of public information were considered, but are not proposed due to the commercial sensitivity of the information involved (it would need to be quite detailed to provide any value).

The option presented in section one of this document regarding Corporate Energy Transition Plans partly addresses issues of information gaps, and could be considered as complementary to the options presented below.

Option 10.4	Provide independent geospatial data on potential generation and electrification sites (e.g. wind speeds for sites, information on relative economics and feasibility of investment locations given available transmission capacity).

Independent information could include wind data on speed for sites, but also information on the feasibility and economics of construction, and consenting issues. The cost of providing this information would depend on its scope and form.

This option would benefit local authorities developing regional and district plans as it could help inform identification in RMA plans of areas suitable for renewables, and help align future planning across transmission, distribution and generation stakeholders. The option would also benefit new investors to a region or area, by providing preliminary information on suitable options that would help their high level scoping assessment before they engaged in more detailed and potentially costly study.

However, it may be that the provision of aggregated consistent wind data for different locations[134] is the only feasible option due to the issue of IP rights of developers who have already developed the relevant information of a potential generation site themselves.

Providing this information to a wider group would undermine any competitive advantage that the earlier developer had obtained, unless they had already secured access and consents to the site. In addition the rapid nature at which generation technology is developing could mean that information could quickly become outdated, requiring frequent reassessment. This would considerably increase costs for the agency undertaking the work.

[134] Detailed indicative wind speed data is freely and/or cheaply available from global models/national datasets, but it requires some manipulation and compilation which may be a barrier for some users

Option 10.5	Extend the data and information provided in MBIE's EDGS and increase the frequency of publication, and potentially recover the cost through the existing levy on electricity industry participants.

The most systematic and regular source of public and independent information on potential demand and generation investment is MBIE's EDGS[135], which have an explicit role in the investment test the Commerce Commission must use in approving Transpower's major capital projects.

In the last decade, the EDGS have been prepared in 2012, 2016 and 2019, and have presented a range of scenarios for growth in demand and capacity at a national level. In future, the EDGS, or something similar, could be updated more frequently, and could include more granular information, such as presenting information at a regional level. The value of more frequent updates to EDGS would be to provide more up to date independent information on a range of potential electricity supply and demand scenarios.

EGDS scenarios are designed to reflect alternative futures that could arise under certain circumstances. None of the scenarios in EDGS are optimised to forecast the 'optimal' future, in the manner that a historical 'central planner' would produce. Hence, consideration would be needed over which scenario(s) should be forecast, if this option was implemented.

The cost of producing the EDGS is currently recovered from tax-payers, but provisions exist for it to be recovered from electricity industry participants through a levy.[136] A shift to levy funding would be based on the principle that those who generate the need for, or potentially benefit from, activities should be contributing towards the costs of the activity. In this case, Transpower and its customers benefit from the provision of independent information to assist with investment planning.

Implementation of levy funding would require annual consultation on the amount of funding, approval by the Minister of Energy and Resources, and, if agreed, recovery of that funding from Transpower. The cost would then be passed on to transmission customers, and ultimately electricity consumers.

Option 10.6	Produce a user's guide on the current regulations and approval processes relating to getting an upgraded or new connection to the grid.

The regulatory processes for new and upgraded transmission and distribution assets are necessary and important, but can create complexity and a barrier for those contemplating electrification, or the connection of generation, particularly if it is small scale.

The purpose of a guide would be to help parties considering new generation or demand to navigate the regulatory and approval process for connecting to the grid. This could assist established investors as well as community groups or other entities considering investing in small-scale generation, and customers considering electrification (including heavy electric vehicles and charging infrastructure, for example).

[135] Available at: www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-statistics-and-modelling/energy-modelling/electricity-demand-and-generation-scenarios/

[136] Under the Electricity Industry (Levy on Industry Participants) Regulations 2010, specifically, under regulation 4(1), which states "the costs incurred by the Crown in relation to developing and publishing regional electricity supply and demand forecasts and scenarios, and related information and analysis, for the purpose of assisting investment planning by industry participants".

This guide could set out the regulatory requirements and processes that need to be followed, and the steps, dependencies, and timelines involved. It could include who parties need to talk to and when, and the kinds of things that need to be taken into account along the way. It would be a simple guide to what is (or a least seems to be) a complicated process. Over time, a guide could be extended to include information on getting an upgraded or new distribution line.

There would be some up-front cost involved in producing the guide, and then an ongoing cost to maintain it when any regulatory or process changes are made. Where the costs fall would depend on which agency or entity prepares it, for example, taxpayers would fund it if a central government department produced it.

Questions

Q10.5	Do you think that there is a role for government to provide more independent public data? Why or why not?
Q10.6	Is there a role for Government to provide independent geospatial data (e.g. wind speeds for sites) to assist with information gaps?
Q10.7	Should MBIE's EDGS be updated more frequently? How often?
Q10.8	Should MBIE's EDGS be more granular, for example, providing information at a regional level?
Q10.9	Should the costs to the Crown of preparing EDGS be recovered from Transpower, and therefore all electricity consumers (rather than tax-payers)?
Q10.10	Would you find a users' guide helpful? What information would you like to see in such a guide? Who would be best placed to produce a guide?

Lack of information sharing for coordinated investment

What is the problem?

While provision of public information could go some way to improve decision making, enhanced information sharing between relevant parties could result in more coordinated investment. There may be information that is more suited to sharing between interested parties, rather than making it publicly available. Better information sharing could also help with better aligning the lead times of new or upgraded transmission assets and the development of new generation or demand.

Areas where there is a potential lack of information sharing between potential investors in generation, large users looking to electrify, and Transpower include:

- information on where there might be spare grid capacity
- information on when potential developers (including of heavy electric vehicle infrastructure) or process heat users in the same area are likely to invest.

This has implications for decision making, and particularly for coordination of decisions between the multiple parties involved. It can have timing implications, and also exacerbates the risks associated with the first mover disadvantage.

There is an interrelationship with the TPM in terms of the incentives it does (or doesn't) create for information sharing and participation in the process/scrutiny of transmission investment proposals. For example, because the current interconnection charge spreads the cost of investment across all customers, those that will benefit most have a strong incentive to engage in the approval process and support it since they will only end up paying only a fraction of its cost. Conversely, it creates a weak incentive for engagement and scrutiny for those that don't benefit as they too only pay a fraction of its cost. The EA's proposed changes to the TPM may resolve some of this concern.

Better information sharing would also help Transpower (as the grid-owner) avoid constraints on the system. Given our open access arrangements, changes could be made to further enable:

- better and more timely decision making
- coordination between renewable generation investors / developers, including with Transpower, and
- coordination between large users looking to electrify and Transpower.

What are the options?

Your views are sought on two interrelated options below, and on what other options could be considered.

Option 10.7	Provide a database of potential renewable generation and demand sources, location and potential size (e.g. wind, geothermal, milk plant).

This option would draw on existing data and information to compile a database on potential new generation and demand that would be updated regularly and proactively.

The Electricity Authority already publishes a database of proposed new generation based on publicly available information, including the status of the proposal in terms of the consenting process and the likely commissioning date. This option would extend this information to include potential new sources of demand, and potentially available capacity on the national grid.

If progressed, this option could include more detailed information that could be shared between interested parties, but equally could include only information that could be published.

It could be voluntary or involve introducing mechanisms to improve coordination of transmission and generation lead times, e.g. requiring developers to talk to Transpower earlier about plans, or the provision of better data on future generation supply to Transpower.

An option could also be to present this in map form to inform decisions by potential investors in generation, large users looking to electrify, and Transpower. Variations also include updating and building on the Regional Renewable Energy Resource Assessments undertaken by EECA about 10 years ago, which were made publicly available, or publishing information compiled from market observers that could be commented on.

This option may be costly to administer, and prove difficult to implement as it could potentially require disclosure of investment plans that parties may not want to disclose (to maintain their competitive advantage). The simple disclosure that another party (even if anonymous) is considering an option at a location could be information that generators want to protect. This risk could be reduced by ring fencing information provision to an entity (such as Transpower).

There is also an open question about who would be best to develop and maintain this database, and how it would be funded. Your views are sought on these matters, in addition to your views on its potential design and value.

Option 10.8	Introduce measures to enable coordination regarding the placement of wind farms to ensure they are more likely to be better distributed around the country.

This option addresses the risk of negative consequences if too many wind farms are built too close together. This risk arises because there is a strong correlation between the output of wind farms located in the same region due to weather patterns. It could be an issue if new wind farms are located close together and/or close to existing wind farms. While the wholesale electricity price provides a signal about transmission constraints at hundreds of locations around the country, it also reflects other factors that affect supply and demand for electricity at any one time (such as outages).

The ICCC's analysis showed that a significant amount of new generation is likely to be wind given its cost, the availability of quality sites, and its relatively low impact on the biophysical environment (and easy reversibility). The ICCC's modelling involved spreading future wind farms across the country to reduce the correlations and manage intermittency[137].

This option could be an extension of option 10.7, drawing on either existing public data, or independent wind site data potentially provided under option 10.4 above. Alternatively, it could just involve potential investors providing data relating to wind sites to an entity (such as Transpower) who could advise on locational risks and constraints. This could be voluntary or mandated, and could include Transpower having different arrangements for information sharing between parts of its business.

Similar to the option above, this option may be costly to administer, and prove difficult to implement as it could potentially require disclosure of investment plans that generators may not want to disclose (to maintain their competitive advantage).

The cost of this option, and risks with information provision, need to be assessed against the potential benefit of avoiding additional electricity system costs relating to managing intermittent wind generation, and the benefit of lower emissions generation.

Questions

Q10.11	Do you think that there is a role for government in improving information sharing between parties to enable more coordinated investment? Why or why not?
Q10.12	Is there value in the provision of a database (and/or map) of potential renewable generation and new demand, including location and potential size? If so, who would be best to develop and maintain this? And how should it be funded?
Q10.13	Should measures be introduced to enable coordination regarding the placement of new wind farms?
Q10.14	Are there other information sharing options that could help address investment coordination issues?

137 For more information, see ICCC Modelling, Wind and Solar Profiles, Final Report, April 2019, available at: https://www.iccc.mfe.govt.nz/assets/PDF_Library/48da95e31a/FINAL-Culy-ICCC-modelling-Wind-and-Solar-Profiles.pdf

Summary assessment of options against criteria

	First mover disadvantage				Information gaps			Lack of information sharing	
	Shift cost and risk allocation from the first mover – optimise asset valuations	**Shift cost and risk allocation from the first mover – delay cost recovery**	**Include benefits of mitigation in Transpower's major capital applications**	**Mechanisms for alternative forms of cost sharing arrangements**	**Provide independent geospatial data on potential sites**	**EDGS: extend data and increase frequency**	**Produce a user's guide on regulations and approval processes for connecting**	**Map of potential renewable generation and demand sources**	**Coordination measures to distribute wind farms**
To what extent is the barrier addressed?	✓	✓	✓	✓	✓✓✓	✓	✓✓	✓✓	✓
Primary benefits – emissions reductions	It is difficult to quantify how these measures might impact emissions, so no attempt is made to compare the relative contribution each option could make								
Primary benefits – EE & RE	✓	✓	✓	✓	✓✓	✓	✓✓	✓✓	✓
Wider economic effects	–	–	✓	–	✓	✓	✓	✓	✓
Compliance costs	–	–	–	–	–	–	–	X	X
Administration costs	X	X	–	X	XX	–	X	XX	X
Energy trilemma – security and affordability	X	X	*It is difficult to quantify how these measures might impact on security and affordability, so no attempt is made to compare them*						

Key:	Option under active consideration	Option not preferred