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**Secretary:** David Inch, david@nzenergy.co.nz

28 February 2020

Energy Markets Policy
Ministry of Business, Innovation and Employment
PO Box 1473
Wellington 6140

By email: energymarkets@mbie.govt.nz

Dear Energy Markets Policy team,

**RE: Discussion Document: Accelerating renewable energy and energy efficiency**

The Independent Electricity Generators Association Incorporated (IEGA) welcomes the opportunity to make this submission on the proposals to accelerate renewable energy in the Discussion Document. [1]

Given the IEGA's focus, this submission relates to proposals in Part B 'Accelerating renewable electricity generation and infrastructure' of the Discussion Document.

The IEGA supports the government's focus on enabling renewable electricity generation investment as this sector is critical to New Zealand's climate change target of a net zero carbon economy by 2050. Substantial new renewable generation capacity is required in the medium term to support electrification of the transport and process heat sectors, or triple the generation capacity we currently have within 30 years. We acknowledge your interest in a decentralised energy system and believe our members can make a significant contribution to sustainability, local energy security, and affordability and well-being.

Our members are innovative, entrepreneurial and passionate about New Zealand's renewable advantage and potential. They have a portfolio of new economic renewable generation projects consented or under investigation which have a smaller environmental footprint than grid-connected generation and provide an incremental, rather than a step change, increase in supply more aligned to increasing local demand for electricity.

Decisions about when to invest depend on a stable and predictable regulatory environment. There is no need to change the fundamentals of the generation market. Regulatory change should build on, and not disrupt, New Zealand's existing low emission activities, such as IEGA members' investment in renewable distributed generation. The Discussion Document focuses on enabling new generation capacity – we suggest any changes should not disadvantage existing capacity. Any government intervention must not pick winners but facilitate private investment and activities.

[1] The Steering Committee has signed off this submission on behalf of members

Historically, small commercial scale distributed generation has contributed more than 12% of peak energy generation. This important contribution was recognised in a 2007 policy decision that has since been removed from the Electricity Industry Participation Code. We would like to see this contribution revisited as part of the way forward for renewable distributed generation in New Zealand.

The IEGA believes that Government will need to assist industry with reducing their factory emissions. Enabling distributed generation up to 10MW to be located close to and embedded within their factory loads is one way to reduce infrastructure costs and contribute to the energy systems. e.g. with strong incentives to use waste-to-energy technologies or reducing penalties imposed by distribution companies on solar peaking capacity.

This is an exciting time for the energy sector, and potentially our members. Distributed generation is already playing an important role in NZ's renewable electricity system contributing more than 12% of peak generation supply and is complimentary to transmission and distribution infrastructure and providing numerous local benefits.

Distributed generation, or distributed energy resources, may become the norm with investment in physical transmission and distribution network infrastructure becoming the 'alternative'. Costs and barriers in the current regulatory system are disproportionate to the scale of investment in our smaller commercial distributed generation.

**Survey of members**

IEGA members were surveyed to assist with feedback on this Discussion Document, including on how to prioritise the proposals. Members were asked for their views on the three key regulatory barriers that are discouraging them from developing or investing in renewable distributed generation plant at this time.

The responses to this question categorically rates as the number one barrier issues relating to the licence to build and operate renewable generation plant granted via the resource management regulatory system and the conservation regulatory system[2]. Complexity, lengthy timeframes and uncertain outcomes were issues heighted as well as uncertainty about ongoing rights to water for hydro generation. We discuss this in more detail in our feedback on Section 7 of the Discussion document.

The second ranked key regulatory barrier relates to issues under the Electricity Authority's (Authority) mandate relating to changes to distribution and transmission pricing methodologies. These methodologies had incorporated compensation for distributed generation when it operated to reduce peak demand on network infrastructure. However, the Authority held an unjustified view that distributed generation does not contribute to grid reliability. Issues raised by members are discussed below in our feedback on Sections 10 and 11 of the Discussion Document.

[2] As well as securing a resource consent under the Resource Management Act (RMA), many projects require a concession consent from the Department of Conversation to access land or renewable fuel. This concession process duplicates the RMA process, is time consuming with uncertain outcomes.

The third ranked key regulatory barrier identified by members is financing related and discussed below in our feedback on Section 8 of the Discussion Document on the proposed PPA Platform.

**IEGA's suggested prioritisation**

In order of priority, the IEGA suggest the following sequencing and optimal package of the policies outlined in the Discussion Document to facilitate renewable distributed generation:

- amend the NPS-REG to provide stronger direction on the national importance of all renewable generation (7.1)
- establish an Expert Panel to assist resource applicants for generating plant of 10MW or less (discussed under section 7)
- implement a pragmatic nationwide solution to recognise the benefits of distributed generation. The previous Avoided Cost of Transmission was such a pragmatic standardised approach. Otherwise distributed generation is not rewarded for its benefits (discussed in answer to question 11.3)
- require Transpower and the Authority to include the economic benefits of climate change mitigation in network planning and cost benefit analyses of proposed Code amendments, respectively (variant on 10.1)
- transmission (and distribution pricing) must include a peak demand price signal (discussed under section 10)
- facilitate PPAs by using the expertise within Green Investment Finance (a variant on 8.1)
- develop a comprehensive definition of community energy reflecting the objectives / outcomes the government seeks to achieve before continuing any further work in this area. We recommend this encompass less that 10MW generation capacity and includes small scale single investors. The role of distribution companies and recovery of their charges also needs a major rethink (discussed under section 9)
- develop a demand response market building on Transpower's pilot programme that includes the opportunity for distributed generation to participate (discussed under section 8.2).

**Achieving the energy trilemma**

The IEGA agrees the "*The Government's Renewable Energy Strategy work programme outlines actions to achieve an affordable, secure and sustainable energy system that provides for New Zealander's well-being in a low emissions world*".[3] However, the work required to implement some of the proposals falls across a number of agencies and involves changes to legislation or frameworks that have no regard to the energy trilemma.

The IEGA suggested in our submission on the Zero Carbon Bill that any target in primary legislation should apply to the activities, purpose or statutory objectives of any government agency that could make decisions with climate change implications.

For example, the Resource Management Act does not consider affordability or security. This is a significant concern for IEGA members, given the proposed National Policy Statement for Freshwater Management and the National Policy Statement for Indigenous Biodiversity severely disadvantages

[3] Page 12 of the Discussion Document

existing and new distributed generation plant.[4] This is also relevant for the Department of Conservation as it is involved in 'approving' renewable generation projects. Any reduction in existing or potential distributed generation capacity will impact affordability, as well as sustainability and security.

In our view, the onus is on all decision makers to ensure the government's objective *to achieve an affordable, secure and sustainable energy system that provides for New Zealander's well-being in a low emissions world* is foremost in any discussion and decision on any regulatory change.

The IEGA supports the government providing guidance to regulators relating to expectation on environmental sustainability and fairness. This avoids any ambiguity. Every agency is part of the overall regulatory system and should be held to account to achieve the government's priorities.

Regulators in fast changing and disruptive markets need to ensure that natural competition prevails, and not become the disruptors and create barriers.

**Recommended approach to small-scale commercial distributed generation**

The IEGA suggests a pragmatic approach across the policy spectrum to address problems caused by the lower economies of scale of the generation capacity and ownership of small commercial distributed generation. A smaller scale and environmental footprint has advantages and our members' plant has an LRMC equivalent to utility scale generation plant.

We recommend MBIE investigate a de-minimus threshold for small commercial distributed generation 10MW or less (but not connected behind a consumer's meter). This de-minimus of 10MW of less should be included as a starting point in key policy, terms and conditions and rules.

Below the de-minimus as a default, all monopoly providers (government, regulators, distribution and transmission providers) should put in place standardised rules, terms and conditions and policies.

A monopoly provider should then have to prove the need for any change to these default arrangements and if any of the default arrangement is changed the government is obliged to review all of the default arrangements together to ensure ongoing consistency. We recommend a cross-agency team decides on low cost standardised arrangements taking into account time, cost and quality.

Small commercial distributed generation is the same as emerging technologies like batteries – and provides the same potential benefits. IEGA warns about the risk that government policy and regulation focuses on this 'bright shiny new thing' to the detriment of existing assets or technologies (eg imposing barriers or costs that have unintended consequences). Policy should be agnostic to technology but focused on the services provided.

[4] Further. the Cabinet paper on the NPS-FM acknowledges the IEGA would disagree with the proposal to treat favour six large hydro catchments by exempting them from achieving the national bottom line standard (as well at the Electricity Authority and Treasury), but dismisses this.

**Submission structure**

Appendix A provides a background on the IEGA and the benefits of distributed generation.

Appendix B is the IEGA's response to policy proposals in the Discussion Document. This feedback is listed in order of priority, as discussed above.

Appendix C includes three case studies:

1. a member's re-consenting experience – over 19 years at a cost of over $0.5 million to re-consent a ~0.5MW hydro generation power plant
2. development and consenting of a new hydro generating plant over a five-year period by which time the regulatory environment had changed significantly impacting the financial viability of the investment
3. a summary of an anonymised version of an Electricity Authority dispute resolution determination between a wind farm and distribution company in relation to connection charges payable. This took six years to resolve and cost a member hundreds of thousands of dollars.

The IEGA would welcome the opportunity to discuss this submission with you in more detail.

Yours sincerely

**Warren McNabb**
Chair

Enclosed:

**Appendix A**: Background on the IEGA

**Appendix B**: IEGA response to policy proposals in the Discussion Document in prioritised order

**Appendix C:** Three Case Studies

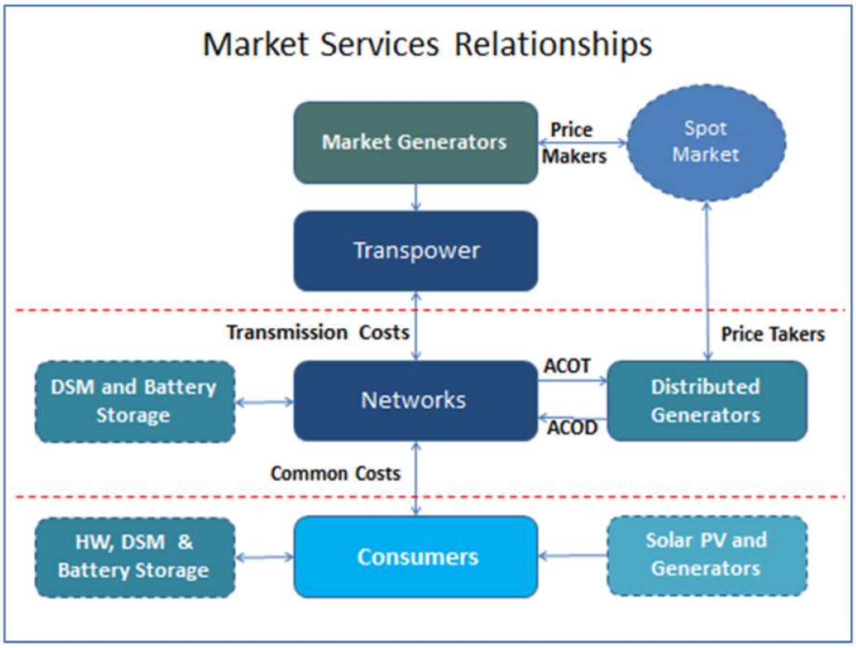
# Appendix A: Background on the IEGA

The IEGA comprises approximately 30 members who are either directly or indirectly associated with predominately small-scale power schemes throughout New Zealand for the purpose of commercial electricity production.

Our members have made significant economic investments in generation plant throughout New Zealand that is embedded within local distribution networks. Our members are proud to contribute to achievement of New Zealand's 100% renewable electricity target with 95% of our electricity generated from renewable fuel compared with ~83% for the entire sector[5]. IEGA members' generation plant range from 0.1MW to around 10MW (with one plant at 25MW and another at 32MW). Combining the capacity of members' plant makes the IEGA the sixth largest generator in New Zealand and the combined portfolio benefits of this group to the energy market are material. At this stage we do not have any investors in solar pv as members.

IEGA members are small, entrepreneurial businesses, essentially the SMEs of the electricity generation sector, providing significant benefits to the regions in which we operate. Members are mostly not vertically integrated with retail. IEGA members' that do not bid their generation output into the wholesale spot market are therefore price-takers. This investment has to be as efficient as utility owned investment in order to be able to make an appropriate rate of return.

IEGA members own distributed generating plants that export electricity in to their local network and for the most part do not utilise transmission services but effectively compete with transmission services to deliver electricity to end users. The services provided by our sector assets differ from market generators and from consumer-owned DG predominately for own use, and the regulatory approach should be commensurately different. The following diagram demonstrates the relationship of distributed generation to other participants.




[5] Source: http://www.emi.ea.govt.nz/Datasets/Wholesale/Generation/Generation_fleet/Existing

**Distributed generation in New Zealand**

The IEGA's focus is on distributed generation that is not behind the consumer's meter. The benefits of this distributed generation are it:

- provides 10% of New Zealand electricity by output (including utility-owned distributed generation) which is equivalent to over twice the output of the Huntly power station
- introduces competition resulting in lower regional electricity prices for consumers as well as enabling new retailers to enter the market with Power Purchase Agreements
- employs around 500 people across most regions of New Zealand
- results in rebates and distributions back to local communities. For example, Pioneer Energy has distributed approximately $75m over 15 years to its community trust shareholder
- assists with security of supply. Many of IEGA members' distributed generation plant supplied their local regional networks prior to the grid being built so have a proven track record of reliable supply as they are designed to run islanded from the grid in an emergency loss of transmission. Recently one of our member's distributed generation plant provided emergency power to Auckland District Hospital Board's Grafton hospital when Vector lost power
- avoids or defers distribution network and transmission investment
- is complementary to consumer load management. These network-connected services have been incentivised to flatten more than 20% of the New Zealand electricity system's peak demand
- analysis in 2017-2018 revealed that over 80% of the assumed contribution of existing distributed generation to winter load (megawatts) is required for Transpower to meet its grid reliability standards to ensure secure supply of electricity[6].

As well as contributing to New Zealand's renewable energy target, distributed generation also improves New Zealand's energy productivity. Energy productivity includes the cost of producing and delivering electricity. Distributed generation can be built at an LRMC equivalent to grid connected generation. Distributed generation is usually located closer to electricity users than grid connected generation and uses only the local network to deliver electricity to users. Grid connected generation (by definition) uses the transmission grid and the local network to deliver electricity. Transporting electricity results in lost energy (due to resistance). Recent data shows 1,239GWhs (3.2% of total electricity injected) was lost while travelling over the transmission grid; 1,670GWh (6%) was lost while travelling over distribution networks.[7] This is equivalent to the output of the Huntly power station.

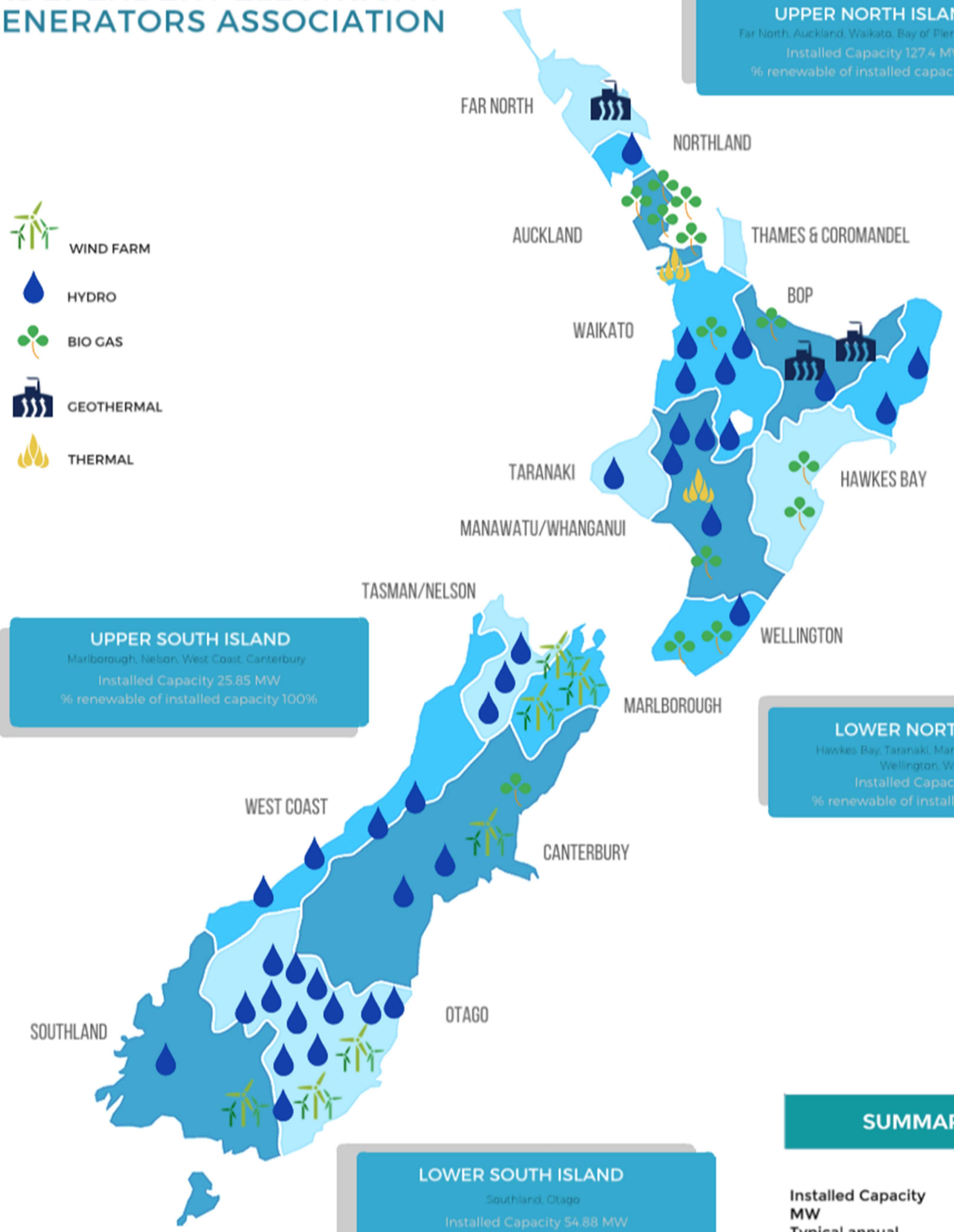
A map of the location and fuel of non-utility owned distributed generation is overleaf.

[6] See Mitton ElectroNet reports on the four transmission regions in consultation to determine the list of distributed generation eligible to receive ACOT https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/acot-code-change-implementation/consultations/#c17067

[7] Top Energy took into account the economic value of lost energy (~6% in their case) when deciding to invest in distributed generation compared with investing in 110kV lines. Top Energy application for an exemption http://www.ea.govt.nz/dmsdocument/21586

# IEGA
## INDEPENDENT ELECTRICITY GENERATORS ASSOCIATION

**UPPER NORTH ISLAND**
Far North, Auckland, Waikato, Bay of Plenty, Gisborne
Installed Capacity 127.4 MW
% renewable of installed capacity 97%




**UPPER SOUTH ISLAND**
Marlborough, Nelson, West Coast, Canterbury
Installed Capacity 25.85 MW
% renewable of installed capacity 100%

**LOWER NORTH ISLAND**
Hawkes Bay, Taranaki, Manawatu, Whanganui, Wellington, Wairarapa
Installed Capacity 58 MW
% renewable of installed capacity 84%

**LOWER SOUTH ISLAND**
Southland, Otago
Installed Capacity 54.88 MW
% renewable of installed capacity 100%

**SUMMARY TABLE**

| | IEGA members | Total DG |
|---|---|---|
| Installed Capacity MW | 266 | 1,148 |
| Typical annual output GWh | 973 | 4,630 |
| $ million invested | 798 | 3,444 |
| % renewable of installed capacity | 95% | 91% |
| Jobs | 200 | 500 |
| Consented (<10MW) | 33.8 | 62.2 |

# Appendix B: IEGA response to policy proposals in the Discussion Document

In order of priority, the IEGA suggest the following sequencing and optimal package of the policies outlined in the Discussion Document to facilitate renewable distributed generation:

- amend the NPS-REG to provide stronger direction on the national importance of all renewable generation (7.1)
- establish an Expert Panel to assist resource applicants for generating plant of 10MW or less (discussed under section 7)
- implement a pragmatic nationwide solution to recognise the benefits of distributed generation. The previous Avoided Cost of Transmission was such a pragmatic standardised approach. Otherwise distributed generation is not rewarded for its benefits (discussed in answer to question 11.3)
- require Transpower and the Authority to include the economic benefits of climate change mitigation in network planning and cost benefit analyses of proposed Code amendments, respectively (variant on 10.1)
- transmission (and distribution pricing) must include a peak demand price signal (discussed under section 10)
- facilitate PPAs by using the expertise within Green Investment Finance (a variant on 8.1)
- develop a comprehensive definition of community energy reflecting the objectives / outcomes the government seeks to achieve before continuing any further work in this area. We recommend this encompass less that 10MW generation capacity and includes small scale single investors. The role of distribution companies and recovery of their charges also needs a major rethink (discussed under section 9)
- develop a demand response market building on Transpower's pilot programme that includes the opportunity for distributed generation to participate (discussed under section 8.2).

The following feedback on specific sections of the Discussion Document is in the above order our suggested prioritisation.

## Section 7 – Enabling development of renewable electricity generation under the Resource Management Act 1991

Building electricity assets is the key if New Zealand is to migrate from carbon-based to renewable fuels. Roughly triple the generation capacity installed currently is required by 2050 – within 30 years – to achieve New Zealand's net zero carbon emissions legislated goal.

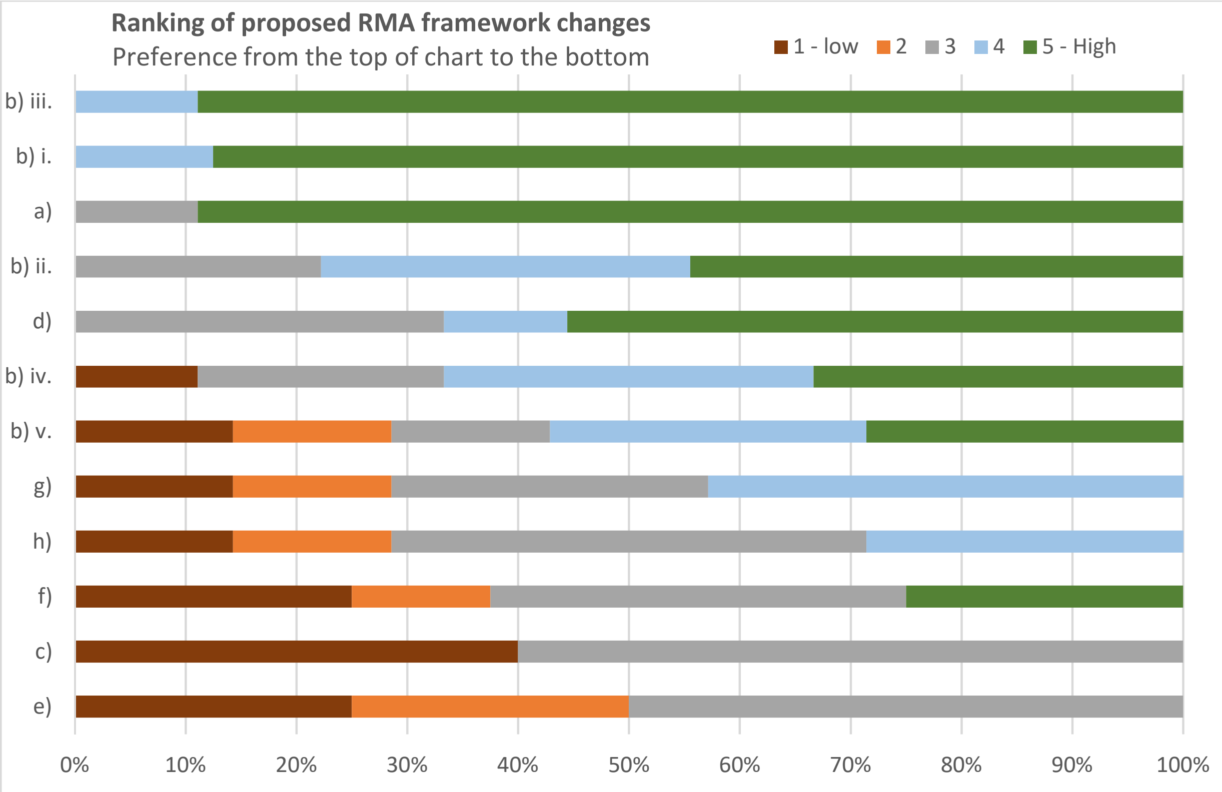
The proposals in this section of the Discussion Document are summarised in the following table (in the order in the Discussion Document). IEGA members were asked if they supported (Yes or No) progressing work on each of these proposals. The percentage in the table is the proportion that replied Yes.

| | | |
|---|---|---|
| a) | Amend National Policy Statement on Renewable Electricity Generation (NPS-REG) to provide stronger direction on the national importance of renewables | 90% |
| b) i. | Develop a new NESREFA that standardises the consent process for re-consenting and repowering (upgrading) existing generation plant | 100% |
| b) ii. | Develop a new NESREFA that standardises the consent process for re-consenting consented but unbuilt generation plant where existing consents are about to expire and / or consent variations are needed to allow for use of the latest technology | 100% |
| b) iii. | Develop a new NESREFA that standardises the consent process for small-scale renewable generation projects of 10MW or less | 100% |
| b) iv. | Develop a new NESREFA that standardises the consent process for any new renewable generation project | 100% |
| b) v. | Develop a new NESREFA that standardises the consent process for adaptive management practices for geothermal generation (eg drilling activities associated with adjusting the location of pipelines and operational plant) | 100% |
| c) | Prescribe standards for shadow flicker from wind turbines in a National Environmental Standard | 80% |
| d) | Develop National Planning Standards to provide councils with more direction | 90% |
| e) | Adopt a stronger spatial planning approach to guide location of potential renewable generation sites | 100% |
| f) | Define particular areas for renewable generation projects which provides a high degree of certainty that RMA approval will be obtained | 100% |
| g) | Government obtains resource consents that are then transferred to a developer | 32% |
| h) | Government identifies renewable generation sites and allocates these for development in a new process (outside the RMA) | 22% |

There is clearly little support from members for the government to get involved in the consenting or access to resource processes (proposals g) and h)). The level of bureaucracy would be significant and it would create yet another significant barrier. People with a direct stakes in the outcomes will be more efficient at these steps.

The IEGA's strong preference is to streamline current arrangements and implement policies that carry more weight and provide strong direction to decision makers.

Members were then asked to rank each proposal from low (1) to high (5) in terms of priority to get the proposals implemented. This graph shows the results.




There is clearly strong support, in order of priority, for:

1. developing a new NESREFA that standardises the consent process for small-scale renewable generation projects of 10MW or less
2. developing a new NESREFA that standardises the consent process for re-consenting and repowering (upgrading) existing generation plant
3. amending the National Policy Statement on Renewable Electricity Generation (NPSREG) to provide stronger direction on the national importance of renewables.

This outcome reflects our experience over many years of lengthy and expensive timeframes and processes associated with meeting statutory environmental obligations for renewable small commercial generation plant. The regulatory regime imposes disproportionate costs on smaller scale plant because the consenting process is a 'one size fits all' approach whether the generation plant is 330MW or 0.5MW. This disadvantages the development of small-scale renewables due to the complexity, risk, cost and time involved. We enclose two relevant case studies in Appendix C. In summary these case studies relate to:

- re-consenting of the 100-year old 0.5MW Raetihi hydro power station took 19 years and cost over $0.5 million (excluding the owner's time). Converting this cost to re-consenting the neighbouring Tongariro Power Scheme of 330MW would cost $330 million

- the decision to invest and fund a new hydro generating plant was made on the basis on a regulatory regime that appeared stable and assisted with funding. By the time all statutory requirements were met, and the plant commissioned 5 years later, the regulatory regime managed by the Authority changed having a significant impact on the financial viability of the plant.

It is critical to remember the RMA process is duplicated if the project requires access to land or renewable fuel that is under the Department of Conservation's (DoC) control. This involves making an identical consent application and awaiting approval for access and information about the concession fee payable for this access. The approach by DoC differs across New Zealand and usually involves lengthy timeframes with highly uncertain outcomes.

We understand DoC is planning a review of its concession fees for electricity generation projects and strongly suggest MBIE participate in this review. Currently the fee structure is regressive and based on the asset value of the investment as opposed to any consideration of the proportion of the project using the conservation estate.

## Addressing IEGA's top 2 priorities

The IEGA recommends a new approach that will address our top two priorities (our feedback on amending the NPSREG starts on page 14).

Our proposal is a **simplified (less complicated) process for a plant of 10MW or less - the 'SME' sector of the generation market** (ie generation that is not connected behind a consumer's meter).[8]

We recognise the importance of the environmental and engagement focus of the RMA. However,

a) the RMA requires numerous studies to be undertaken prior to an application being lodged that can be proven to be completely irrelevant during the consenting process for generating plant of 10MW or less. For example, the following noise study requirements were imposed on the consent applicant for the Flat Hill wind farm: a noise study was provided as part of the RMA application; a peer review of the noise study was required to be provided for the RMA hearing; and then when settling a potential Environment Court appeal a second peer review was required. No substantive risks or concerns were raised in either of the studies and just exposed the small 7MW project to more expense; and
b) each consenting authority has discretion to consider an application with its own approach / process / focus. For example, consenting authorities can impose different methodologies for testing the same particular effects.

We **suggest an Expert Panel** be created that can assess a generating plant proposal and shape the consent application at an earlier stage before any studies are undertaken. The Expert Panel would have:

- knowledge and expertise of all generating technologies and apply a consistent approach or criteria across projects across New Zealand
- regard to and act consistent with all government policies and objectives

[8] Other statutory obligations are simplified or tailored for SMEs relative to large scale / utility businesses.

- regard to Regional Council Plans but could encourage a consistent approach across New Zealand to monitoring and testing ongoing compliance with consent conditions. For example, different councils apply different rules for the passage of the same fish past power stations in different catchments – increasing costs for members' have plant located in different areas of New Zealand
- authority to determine what studies are required
- ability to shape the consent application by identifying the issues associated with the project that have to be further investigated or addressed in the consent application, ie determining the consented activities. Determinations would be binding through all consenting processes (RMA and DoC)
- authority to impose conditions which, if met, would not be re-litigated during the consent process by the consenting authority. Or it could impose conditions that form a minimum threshold – this threshold could be exceeded if the investor does a study to satisfy that the aspect of the project is not an issue, eg, a hydro plant that diverts less than 25% of the river's flow is allowed; or the project can take more than 25% if a study proves this will not have a detrimental effect

The advantages of an Expert Panel are:

- provides a higher level of certainty for investors considering a proposal prior to making a significant investment in the regulatory process
    - an investor currently undertakes a large amount of work at considerable cost to put their best foot forward in a consent application but there is absolutely no certainty about whether the information prepared will be sufficient to satisfy the consenting authority
- reduces the cost of undertaking studies to support a consent application
    - Expert Panel will determine the studies that are directly relevant to the application
- hastens consenting timeframes – removing bureaucratic drag. The consenting authority could then be required to approve the consent within a maximum time limit
- creates a consistent approach to reviewing applications across New Zealand
- would use the knowledge of a century of renewable power schemes in New Zealand
- applicants are dealing with an expert body
    - our members are dispersed across New Zealand and are often dealing with small local authorities that infrequently deal with consenting generation plant[9]
- process works for reconsenting, repowering and new generation projects
- is consistent with other rules faced by distributed generation in the electricity market
    - Electricity Industry Participation Code has a de-minimus of 10MW in relation to the obligations to the System Operator

This Expert Panel would be consistent with the 'one-stop-shop' process proposed in the European Union for small-scale projects:

The European Union "Proposal for a DIRECTIVE OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL on the promotion of the use of energy from renewable sources"[10] included the following process for repowering:

[9] This differs from say Meridian and Genesis that deal with one consenting authority for the entire Waitaki power scheme or Mercury for the Waikato power scheme

d) Administrative simplification: (1) reinforced provisions with "one-stop-shop", time ranges and facilitated procedures for repowering; (2) permitting procedures time limited, through automatic approval and simple notification for small projects.

A combination of Options 1 and 2 is preferred for this Proposal, in order to establish a permit granting process for renewable energy projects with one designated authority ("one-stop-shop"), a maximum time limit for the permit granting process, a simple notification to Distribution System Operators for small scale projects and a specific provision on accelerating permit granting process for repowering existing renewable plants. This option allows achieving clearer, more transparent, predictable and less time-consuming permitting processes for applicants.

This option is proportionate as it is to a large extent the implementation of best-practice procedures that already exist in some Member States. It does not entail high costs. It respects subsidiarity as it leaves Member States the choice of how to organise the one-stop-shops. It also does not interfere with the content of the permitting procedures.

***Answers to specific questions in Section 7***

Q7.1 Do you consider that the current NPSREG gives sufficient weight and direction to the importance of renewable energy?

The Discussion Document states revising the NPSREG is a priority of the Renewable Energy Strategy work programme[11]. Considerable feedback has been provided, over an extended period, on suggested improvements to the NPSREG to improve its effectiveness.

IEGA supports changes to the NPSREG to make this instrument more directive. We note the NPSREG categorises small commercial DG as of national significance. However, IEGA members can provide numerous examples of how the RMA constrains investment in renewable generation. The IEGA does not have the technical or legal resource to suggest specific rewording of the NPSREG but we have made the following comments in previous submissions:

- the NPSREG must be more prominent and taken more seriously by decision makers
- the NPSREG has equal weighting with numerous other criteria in the RMA so has no 'teeth'
- there is little consistency between regions / districts as to the provisions that apply to the operation, maintenance and development of renewable electricity generation activities
- the provisions in the NPSREG are not as directive or 'forceful' as those within the New Zealand Coastal Policy Statement or the National Policy Statement on Electricity Transmission which impacts on its implementation within lower-order statutory planning documents
- the NPSREG has not provided any certainty for the re-consenting of existing renewable electricity generation schemes.

Q7.2 What changes to the NPSREG would facilitate future development of renewable energy? In particular, what policies could be introduced or amended to provide sufficient direction to councils regarding the matters listed in points a-i mentioned on page 59 of the discussion document?

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[10] See https://eur-lex.europa.eu/resource.html?uri=cellar:3eb9ae57-faa6-11e6-8a35-01aa75ed71a1.0007.02/DOC_1&format=PDF

[11] Page 58 of the Discussion Document

Maybe the NPSREG objective or purpose statement should include a statement about how this regulatory instrument contributes to, or is an integral part of achieving, the government's climate change and renewable energy targets, as well as the commitment to transition to a low emissions economy. This would provide clarity to everyone about the overriding driver for consenting renewable electricity generation plant. This is different from point a. explaining *how to consider the national benefits of renewable generation when making decisions on renewable energy consent applications*.

### Q7.3 How should the NPSREG address the balancing of local environmental effects and the national benefits of renewable energy development in RMA decisions?

As for our answer to question 7.2, everyone has a role in achieving a low emissions economy.

### Q7.4 What are your views on the interaction and relative priority of the NPSREG with other existing or pending national direction instruments?

The NPSREG must have at least equal standing or priority with other existing or pending national direction instruments. This is particularly important in relation to the proposed NPS for Freshwater Management (NPSFM) and NPS for Indigenous Biodiversity (NPSIB).

The NPSFM proposes exemptions from national bottom-line standards for hydro generating plant in six major catchments. This places all other hydro generation, including members' plant at a competitive disadvantage to the utility owned hydro generating plant. This is clearly inequitable.

Further, the draft NPSIB defines renewable electricity generation connected to the national grid as nationally significant infrastructure with lesser requirements relative to all other renewable electricity generation. This is obviously inconsistent with the NPSREG which includes small and community-scale renewable generation activities as nationally significant.

The onus is on all parts of government to ensure a consistent approach which does not disadvantage one group of renewable generation plant relative to others. Closure of existing generation because of this biased approach only lengthens the journey New Zealand is on to transition to a low emissions economy. Further, the government must decide what takes environmental precedent. The legislated new zero carbon target, in our view, is the primary objective of government and all government agencies should take this goal into account when developing government policy instruments and mechanisms. MBIE should be aware that the current draft NPSIB will mean that most, if not all, new wind farm design will need to avoid all indigenous features with no effect of offset potential.[12] This is in direct contradiction to achieving a significant increase in New Zealand's renewable generation capacity by 2050 to achieve a net zero carbon economy.

### Q7.5 Do you have any suggestions for how changes to the NPSREG could help achieve the right balance between renewable energy development and environmental outcomes?

We recognise the importance of the environmental focus of the RMA and NPSREG. However, renewable electricity developments displacing thermal generation also have strong positive environmental outcomes. This is a difficult balance but New Zealanders and the government have to

[12] The IEGA will be making a submission to the Ministry for the Environment on this draft NPSIB but discussion between government agencies is critical.

decide whether mitigating or adapting to climate change outweigh maintaining the overall equivalent of a 'status quo' for New Zealand's environment.

We suggest New Zealand has options for new small-scale commercial distributed generation with a small environmental footprint which are currently locked up in Crown ownership of land. There is significant hydro generation resource in the high country – where there is rainfall and a 'head' to maximise generation output. The Conservation estate covers about 30% of New Zealand's land mass. Land with low conservation value could be made available for small-scale renewable generation development.

The Crown also owns high country pastoral land under long-term tenure leases to farmers. Under these leases, tourism has been 'approved' as an allowable activity on this land. We strongly suggest small-scale renewable generation development also be an approved activity.

### Q7.6 What objectives or policies could be included in the NPSREG regarding councils' role in locating and planning strategically for renewable energy resources?

As discussed above, everyone has a role in achieving a low emissions economy – including local government. The IEGA notes members' have limited resource to monitor and engage in local council initiatives to amend or develop regional plans. More guidance from government and a more consistent approach to consenting and monitoring across local councils is highly desirable, particularly in relation to water take and use.

We need clear direction from central government to allow/ make regional government's decision making more transparent and unbiased.

### Q7.7 Can you identify any particular consenting barriers to development of other types of renewable energy than REG, such as green hydrogen, bioenergy and waste-to-energy facilities? Can any specific policies be included in a national policy statement to address these barriers?

The NPSREG should cover be renewable fuel agnostic – applying to any fuel from which electricity can be generated.

### Q7.8 What specific policies could be included in the NPSREG for small-scale renewable energy projects?

Any change to the NPSREG should not lessen the current status of small-scale renewable energy projects – currently stated as nationally significant. The NPSREG could recognise that small-scale projects have a smaller environmental footprint. They can also be more remote (serving local communities) than utility scale generation projects that require connection to the transmission grid.

The NPSREG treats all renewable electricity generation activities equally. It is critical this approach is consistent across all national policy instruments. The IEGA recently submitted on the proposed NPSFM that we strongly disagreed with the proposed exemption approach to hydro electricity generation infrastructure in the draft NPSFM. All existing hydro generation capacity has equal weight in the NPSREG and must be placed on a consistent equal footing under the NPSFM. The proposed exceptions approach for the six large hydro catchments is anti-competitive, discriminatory and inequitable. All electricity is an essential service for human wellbeing and all plant generating electricity must be treated equally. The work proposed by MBIE to enable renewable electricity generation by improving the NPSREG could be quickly undone by the proposed NPSFM.

The same feedback applies with respect to the NPS on Indigenous Biodiversity which defines renewable electricity generation connected to the national grid as nationally significant infrastructure with lesser requirements relative to all other renewable electricity generation.

As discussed in our answer to Q7.4 consistency across instruments of government as well as within particular instruments is essential.

### Q7.9 The NPSREG currently does not provide any definition or threshold for “small and community-scale renewable electricity generation activities”. Do you have any view on the definition or threshold for these activities?

As discussed above a generating plant of 10MW or less should be classified as small. This is consistent with the approach in the Electricity Industry Participation Code.

### Q7.10 What specific policies could be included to facilitate re-consenting consented but unbuilt wind farms, where consent variations are needed to allow the use of the latest technology?

Re-consenting consented but unbuilt wind farms should involve a process that reviews only the aspects of the consent that is changing and not re-litigate all consent conditions.

### Q7.11 Are there any downsides or risks to amending the NPSREG?

The IEGA suggests work be prioritised on drafting amendments to the NPSREG and the downsides or risks from the proposed amendments can be consulted on at the same time. We would welcome the opportunity to participate in a thorough and wide-ranging review of this policy instrument given the significant need for new renewable generating capacity if NZ is to transition to a low emissions economy.

***Another suggestion to improve the RMA impost on small scale commercial distributed generation***

MBIE could investigate financial tax deductibility of costs associated with the consenting process - a bit like the approach to research and development.

## Section 11: Local network connections and trading arrangements

The IEGA (obviously) strongly agrees with the following from the Discussion Document[13]:

> Distributed generation can play an important role in maintaining system security and reliability, and potentially provide a lower-cost alternative to investing in transmission or distribution networks directly. As a Distributed Energy Resource (DER), it can also reduce electricity losses, and provide incremental increases in supply that are more aligned to local growth in demand. Other DER includes rooftop solar, battery storage, and demand response. Distributors can enable DER by providing a neutral platform to providers to facilitate two way power flows.

We note that the Discussion Document *"does not have any specific recommendations on reducing distribution barriers, instead we seek information on your experiences, and on whether there are any gaps not addressed by current and planned future work outlined below in relation to the three areas identified".*

As a reminder, the IEGA's focus is on small scale commercial distributed generation. The Discussion Document does not appear to distinguish between household or behind the meter distributed generation and small scale commercial distributed generation. Part 6 of the Electricity Industry Participation Code has a standardised connection process for distributed generation up to 10kW.

The IEGA suggests it is important to facilitate both household and small scale commercial distributed generation. Any arrangements for one should not preclude or disadvantage the other. With some form of control a group of household distributed generation could be equivalent to small scale commercial scale distributed generation – it just require a control/grouping mechanism.

Uncertainty about the Authority's approach to distributed generation and possible further changes to current regulatory arrangements managing the relationship between local network companies and distributed generation were the second key regulatory priority for our members.

Our comments on this chapter have been provided as answers to specific questions in the Discussion Document.

### Q11.1: Have you experienced, or are you aware of, significant barriers to connecting? Are there any that will not be addressed by current work programmes outlined above?

IEGA members experience difficulty and issues relating to negotiating with monopoly distribution companies for connection and charges.

Part 6 of the Electricity Industry Participation Code stipulates timeframes in relation to connection agreements but these are not adhered to. The distributed generation owner could take a dispute to the Authority but this is with the party you are trying to connect to and create a long term relationship with.

Also under Part 6, connection charges are limited to incremental costs but the distribution company determines how much is new to enable connection for distributed generation and how much is something that the distribution company wants for its network (eg. communications systems).

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There are examples of distribution companies preferring distribution solutions without discussing if the distributed generation could make a lower cost investment that achieves the same outcome. Appendix C includes a case study on a dispute that took **six years** to resolve between an IEGA member and a distribution company that **cost hundreds of thousands of dollars** because the distribution company was acting as a monopoly provider. In early 2019 the Authority published a case study of their investigation into the dispute. This is a clear articulation of the issues, including evidence of poor behaviour, that can and does form a barrier for distributed generation.

Distribution companies' also view distributed generation as only a cost when distributed generation can and does provide services to distribution companies which they are not being paid for.

The mindset and expertise of distribution companies is focused on traditional distribution infrastructure assets. A wider perspective could result in distribution companies working with owners of distributed energy resources (DER) to manage capacity or power quality issues on the network. For example, the Authority is about to change the Code to impose a limit of 3MW per household installation of solar pv in areas of the network that the distribution company has classified as congested. An alternative would be for the distribution company to use the investment made by consumers in solar pv to reduce the demand for electricity from the grid (reducing capacity utilisation during periods of the day) and encourage the consumer to also install a battery which could be controlled by the distribution company to manage congestion.

Revised technical standards or a different approach to first-come-first-served could be relevant for behind the meter energy connections. The IEGA submits this should not apply to small scale commercial distributed generation. These investors have a direct relationship with the distribution company including bespoke connection assets. The analogy is the approach to direct connected load on the transmission grid versus all other load.

The IEGA is engaged with the Authority's Open Networks work programme, although the public face of this thus far appears to be on behind the meter energy.

Significant investment is planned for distribution networks as many assets are approaching the end of their economic lives. Further, population growth as well as the government's housing investment is seeing the development of substantial new housing areas. Government could pilot development of a new network area that is built for a low emissions future, rather than based on the status quo.

### Q11.2: Should the section 10 option to produce a users' guide extend to the process for getting an upgraded or new distribution line? Are there other section 10 information options that could be extended to include information about local networks and distributed generation?

Transpower publishes considerable information about the state of the transmission grid and potential constraints. Their development of a major capital expenditure application includes a comprehensive process to identify non-transmission solutions.

Distribution companies have the same regulatory requirement to analyse alternatives to investment in distribution assets. This process has happened infrequently and appears to be more of a 'box ticking' exercise than representing a genuine interest in contracting distributed generation or other alternatives.

Q11.3: Do the work programmes outlined above cover all issues to ensure the settings for connecting to and trading on the local network are fit for purpose into the future? Are there things that should be prioritised, or sped up?

**Issues with the arrangements for trading on the local network**

The issue that distributors investing in distributed energy resources (DER) could unduly lessen competition in the emerging DER market[14] is perennial. The regulatory regime should ensure that the distributor is competing on a level playing field with third party investors in DER. For example, everyone has the same information about the network and where best to invest and receive the same compensation for any services that assist with managing the network.

Distribution companies' discretion to categorise a network area as 'congested' has implications for the growth of DER.

**Issues with pricing and cost allocation for network connections and services**

IEGA agrees that distribution pricing should signal peak demand periods and potentially encourage a reduction in consumption, increase in consumption from consumer owned generation or increase in output from small commercial distributed generation, and that owners of these assets are compensated.

Consumers sign up to reducing demand during peak demand periods by going on controlled as opposed to uncontrolled tariffs. These consumers benefit from lower distribution tariffs – between 1c/kWh and 8c/kWh across New Zealand (and average of $3.5/kWh).

IEGA members' generation plant can and do provide unpaid benefits to distribution companies. The IEGA submits progress in valuing these benefits and agreeing compensation is overdue. MBIE could standardise the value for reliability and ancillary services provided by distributed generation across all networks. For example, the value of reliability should be standard across New Zealand when the value of lost load in the transmission context and security of supply framework is set at one number of $20,000/MWh.

Currently small commercial DG receive no compensation from distribution companies for generating during periods of peak demand and reducing the volume the distribution company has to carry from the national grid. The IEGA submits that this is inequitable relative to other customers of the distribution company.

The different policies applied by lines companies and poor approach leads us to **recommend a pragmatic nationwide solution to recognise the benefits of distributed generation**. The previous Avoided Cost of Transmission was such a pragmatic standardised approach. Otherwise distributed generation is not rewarded for its benefits.

[14] Second last paragraph Page 119 of Discussion Document

**Contracting for network support**

Trial framing of EDBs requirements for network support and introduce contestable procurement to discover a range of solutions. Develop the necessary processes to support contestable procurement of network support from trial experience. Move to regular practice, practiced consistently across all EDBs.

The Electricity Network Association Network Transformation Roadmap[15] includes the following task to build and adapt network capability. The IEGA strongly supports this work being prioritised and welcomes the opportunity to engage in whatever process is implemented to achieve this.

**Incremental costs**

Part 6.4 of the Code requires that distribution companies charge distributed generation owners' incremental costs of distribution services. In its May 2016 consultation paper, the Authority proposed to change the incremental cost rule to allow distribution companies to allocate a portion of their common costs to connected distributed generation. Following submissions, the Authority decided not to proceed with any change.

The IEGA's submission provided evidence that common costs allocated to distributed generation owners could be $20–$40/MWh, equivalent to 25–50% of a long run spot price of $80/MWh.

IEGA commissioned PwC to analysis the financial implications of these charges for members[16]. Payment of common costs resulted in a significant increase in average total operating expenses of 45% and 90% assuming common cost payments of $20/MWh and $40/MWh respectively.

Assuming members also lost any Avoided Cost of Transmission revenue and faced common costs of $20/MWh and $40/MWh resulted in financing ratios that would be unacceptable to banks providing debt funding. There would therefore have been serious financial consequences for existing distributed generation investors. For example, increasing the average net debt to total assets ratio to 61% and 87% respectively; increasing the net debt to EBITDA ratio to over 8 times.

In our view, the issue of distribution companies' allocation of common costs to small commercial scale distributed generation has been thoroughly analysed and reviewed and the decision by the Authority does not need to be re-litigated. We are surprised the topic has been included in the Discussion Document and welcome the opportunity to discuss this with you if further work is proposed.

### Q11.4: What changes, if any, to the current arrangements would ensure distribution networks are fit for purpose into the future?

The IEGA recommends the approach to regulatory arrangements outlined in the report "ReShaping Regulation, Powering from the Future" [17] which describes regulatory principles to shape a new energy system from a blank sheet of paper. This paper comments that the focus on 'transition' is "*resulting in incremental rather than systemic thinking that is creating significant policy and cost "drag", is constrained by incumbent thinking and does not draw sufficiently from drivers of change beyond the energy sector. … Prescription is yesterday, facilitation is tomorrow, all judged against great consumer outcomes.*"[18]

[15] See https://www.ena.org.nz/dmsdocument/484

[16] See report at https://www.ea.govt.nz/dmsdocument/21168-independent-electricity-generators-association-attachment-a

[17] See https://www.imperial.ac.uk/media/imperial-college/grantham-institute/public/publications/collaborative-publications/Reshaping-Regulation-Powering-from-the-future.pdf

[18] Ibid Page 4

## Section 10: Connecting to the national grid

The IEGA has a stake in issues relating to connecting to the national transmission grid. While not connected to the grid, distributed generation competes with (is an alternative to) electricity delivered by the transmission grid.

In addition, recent analysis has revealed that 80% of existing distributed generation's contribution to winter peak load (MW) ensures that Transpower meets its grid reliability standards.

The Discussion Document does not mention the role of peak demand price signals in managing electricity demand efficiently or reducing the need for additional investment in renewable generation, distribution or transmission capacity. We have not attempted to quantify the impact of peak demand price signals as we transition to a low emissions economy. However, we have estimated a portion of the cost if distributed generation no longer supplies electricity during periods of peak demand[19] - the value of the lost electricity (as demand is met instead by grid connected generating plant located distant from load) could be $500 million per annum. We suggest government has a role in ensuring an efficient allocation of transmission costs to consumers that recognises the international perspective that peak demand drives the need for new capacity.

Our other point that is not recognised in the Discussion Document is that generating renewable electricity does not mean that the transmission grid is necessary to transport that energy. Distributed generation does not use the transmission grid. If / when hydrogen plays a role in New Zealand's energy future (behind the meter or where there is no meter) this renewable energy will not use the transmission grid.

The Discussion Document canvasses a number of options - feedback on the options relevant to the IEGA follows.

*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.*

The IEGA supports this option. Further the emissions cost of electricity lost due to resistance as it moves from remote generation to load must be taken into account. Transpower are required to consider non-transmission solutions in any investment decision. Inclusion of emissions prices could make more non-transmission solutions more economically valuable that traditional transmission infrastructure investment. If / when this is the case Transpower must have contractual and compensation arrangements in place to commit to the non-transmission solution.

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[19] This is in the context of IEGA submissions on the Electricity Authority's transmission pricing proposals and changes to the avoided cost of transmission mechanism. It is bizarre that investors in new distributed generation now have to negotiate with Transpower for services distributed generation provides when Transpower competes with distributed generation to deliver electricity to end consumers.

*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:*

*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.*

The IEGA agrees that Transpower should progress investment based on the best available information at the time. If this results in overinvestment for a period of time, because demand does not increase as fast as expected, we suggest the shareholder can bear the risk of underutilisation in the context of the need to transition to a low emissions economy. This is preferable to a regulator making a post investment decision that an asset is uneconomic and the costs cannot be recovered. At the same time there should be rigour about whether the valuation of the asset is fair or should be revalued.

Lumpy investment in transmission infrastructure, due to huge economies of scale, does not mean the system value provided by distributed generation changes over time.

Distributed generation can defer investment in transmission up to the point when a lumpy investment can no longer be avoided. Distributed generation is a long-life asset, like transmission, with a number of plant around New Zealand over 100 years old. Figure B below represents the correct analysis of the economic efficiency impacts of distributed generation on excess supply of delivery capacity. Further, it is common and acceptable to have surplus capacity following an economically sized infrastructure expansion that meets future demand projections.

Investments by both Transpower and distributed generation are efficient, and both should be allowed to be compensated by adequate cost recovery.

Figure B - *Correct Economic Perspective: DG is part of in-use capacity, Transpower upgrade results in excess capacity (AIEG)*

*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).*

The IEGA suggests there is a substantial amount of information already available and that commercial incentives already drive an understanding of potential sites for new generation. We do not support this option.

*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 IEGA supports extending and increasing the publication frequency of MBIE's EDGS analysis. This has significant public benefits including potential new entrants that would not be subject to the existing levy on electricity industry participants.

*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.*

The IEGA suggests commercial factors will drive the location of new wind farms. There is some diversity in wind flows across New Zealand. Nodal spot prices will compensate wind farm owners for this diversity. We do not support this option.

## Proposal 8.1: Introduce a Power Purchase Agreement (PPA) Platform

The IEGA notes this proposal aims "*to provide investors with greater certainty regarding future electricity demand growth and help to manage wholesale power price exposure (also referred to and merchant power price risk)*".[20]

We also understand that the aim of this proposal is to match new small-scale generation with local industrial load that is converting to electric processes. We agree that for these energy users in-house know-how, such as the legal expertise required to negotiate long-term deals, and other resources, may be limited[21].

We also agree access to any 'Platform' does not need to be available to large scale generation and load which already have the economies of scale to reach long-term deals.

In our view, the current market attributes that make it difficult for small-scale renewable generation investors to secure finance are:

- non-firm generation is very difficult to hedge with ASX products which makes the ASX market unsuitable to IEGA members
- new grid scale generation results in a stepwise increase in electricity volumes which applies downward pressure on spot prices impacting the likely return on investment. This factor, which impacts investment timing, is unlikely with small commercial DG
- managing spot price or merchant power price risk - members are price takers for their generation output. They do not have the financial or physical resources to man a 24/7 desk bidding into the wholesale spot market to influence the spot price
- attempts are made to manage spot price risk by using the hedge market but this is volatile and has limited liquidity
- the absence of a longer dated contract market is one of the factors inhibiting expansion or new investment. It is difficult to negotiate with vertically integrated gentailers that make up ~90% of the generation and retail market and who 'control' the hedge market
- renewable generation projects involve a high upfront cost to construct and this cost is recovered over the long life of the asset. Regulatory certainty is therefore critically important to the bankability of these projects. Distributed generation investors currently face a regulatory environment that might only become more stable in about five years when changes to the TPM and distribution pricing are in place. The level of uncertainty is disproportionate to the size of this sector and the scale of the businesses owned by IEGA members. This uncertainty is also impacting the bankability of existing and new distributed generation investments.

Other regulatory issues that we are concerned about are:

- issues relating to negotiating with monopoly distribution companies
- issues for new DG negotiating with Transpower
- engagement with the Authority

[20] Page 69 of Discussion Document
[21] Page 69 of Discussion Document

All of these barriers or concerns culminate in it being difficult for independent small commercial investors to debt fund new generation projects. Some fundamental changes to the wholesale market may be required to achieve change, as efforts to improve liquidity in the hedge market have had limited impact since 2010.

Membership support for Option C is the highest from our survey – although it is 50 / 50. Existing rules provide for PPA between generators and consumers. However, any assistance towards enabling easier and a more widely utilised PPA market would be beneficial. We query if limits on just central or regional government participation is ideal, or making this only available for new loads and generation. These two options may have some place if they are used as a type of lower risk proof of concept and then quickly widened to maximise the benefit.

Other options to facilitate new small-scale commercial distributed generation close to load that needs to electrify could be:

- establish a fund that allows a contribution towards construction cost, particularly when this generation contributes to wider benefits
- widening the scope so that access to a long term contract (PPA) for managing price risk (hedging) is available to small scale generator that is not large enough to trade on the ASX (noting, also, the costs of ASX transactions, margin calls etc)
- financial assistance at a proportion of the LOCE (say $20/MWh) with the balance of revenue being the responsibility of the renewable generation investor

The IEGA cautions any proposal that creates excess bureaucracy and a further layer of costs. We also suggest the New Zealand Green Investment Fund may be the appropriate agency to implement any proposals - given its focus on established technologies, green energy and finance focus.

## Section 9: Facilitating local and community engagement in renewable energy and energy efficiency

The IEGA appreciates the definition of community energy provided in the Discussion Document:

> *"community energy as any renewable energy activity that is managed in an open and participative way, and has local and collective benefits and outcomes. Community energy includes both communities of place (defined by the places people live, such as a neighbourhood or region), and communities of interest (defined by a shared interest, such as a sports club or national co-operative)."* [22]

IEGA's members' small-scale commercial and renewable distributed generation is embedded in the local network and is part of the local community. Some member organisations are 'owned' by the local community. Even if the organisation is not owned by the local community, our members' distributed generation plant provide numerous benefits to their local community.

For example, NZ Energy owns and operates generation, the distribution network and retails electricity in the Haast area (islanded from the transmission grid) at prices that are the lowest of any region in New Zealand.

Members' bring technical expertise in small scale commercial distributed generation to provide the following benefits to local communities:

- building and maintaining local generation plant at a cost (LRMC) equivalent to grid connected generation (which is important to participate in electricity market arrangements)
- employing local people for construction and maintenance across most regions of New Zealand
- procuring local supplies to construct and maintain assets
- introducing competition resulting in lower regional electricity prices for consumers
- paying rebates and distributions back to local communities. For example, Pioneer Energy has distributed approximately $75m over 15 years to its community trust shareholder
- assisting with local security of supply and resilience. Many of IEGA members' distributed generation plant supplied their local regional networks prior to the grid being built so have a proven track record of reliable supply as they are designed to run islanded from the grid in an emergency loss of transmission
- avoiding or deferring distribution network and transmission investment reducing the overall cost of electricity for all consumers
- complementing consumer load management - these network connected services have been incentivised to flatten more than 20% of the New Zealand electricity system's peak demand
- improving New Zealand's energy productivity by avoiding losses of electricity over the transmission and distribution networks. Recent data shows 1,239GWhs (3.2% of total electricity injected) was lost while travelling over the transmission grid; 1,670GWh (6%) was lost while

[22] Page 93 of Discussion Document

travelling over distribution networks.[23] This is equivalent to the output of the Huntly power station

- providing local power as well as the security of energy on demand from the national network.

Given the nature of IEGA members' investment, being embedded in the local community, the trust of local consumers is a critical part of their ongoing licence to operate. IEGA members take this very seriously.

It would be interesting to understand consumers' perceptions of the 'social licence' to operate for small commercial scale distributed generation relative to utility scale generation plant. We suggest MBIE commission a study to evaluate the public's preferences in relation to the scale of future renewable power schemes. This could identify the social cost of utility scale versus incremental smaller regional generation capacity and assist with identifying and addressing barriers to new generation investment.

Member feedback included the following benefits of community energy: local ownership and investment in community resilience; better local engagement in the consenting and ongoing operation of the electricity plant; could include or enable recreational access; community drives for and achieves a low or zero carbon energy footprint.

The IEGA has some concerns about a focus on 'community' energy, namely:

- it is important the community has the ongoing financial and technical capability to ensure safe operation of these investments in assets with very long lives. A not-for-profit structure may be inconsistent with these ongoing commitments or the level of profit may not be sufficient to be distributed in a way that meets community expectations
- potential loss of efficiency due to scale benefits
- query whether 'community' investment will have the scale to generate and distribute electricity efficiently or result in lower prices for its constituents
- a community energy scheme, unless disconnected from the distribution network, will have to be part of the electricity system and be compliant with a complex array of requirements.

The IEGA submits the benefits a community aims for from investing in a community energy scheme can be delivered by working with an experienced investor in local renewable electricity generation. IEGA members have the technical expertise to build and operate plant that is competitive with utility scale generation plant. The challenge is to facilitate connection between local communities and IEGA members or potential small-scale commercial investors and deliver new generation capacity that meets both parties' ambitions.

Before continuing any further work on community energy we suggest a comprehensive definition of community energy be determined. We recommend this encompass less that 10MW generation capacity and needs to include small scale single investors. The definition will also reflect the objectives / outcomes the government seeks to achieve from community energy.

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[23] Top Energy took into account the economic value of lost energy (~6% in their case) when deciding to invest in distributed generation compared with investing in 110kV lines. Top Energy application for an exemption http://www.ea.govt.nz/dmsdocument/21586

For community energy to work there will first need to have a major rethink/revamp of what role distribution networks play and how their charges are recovered. Distribution networks will be an integral part of a successful community energy deployment

The Discussion Document outlines problems for community energy.[24] The following table lists these and the IEGA's feedback.

| Problem | IEGA feedback |
|---|---|
| Market arrangements: | |
| • Ensuring electricity distributors have the necessary incentives, data and know-how to identify and promote distributed energy solutions and engage with community actors. | Information on current and forecast 'congestion' in distribution networks is going to be critical in the future as the EA is likely to implement a rule that limits consumer scale solar to 3kW in congested areas.<br>The IEGA suggests network companies should be investigating and facilitating ways that distributed generation can assist with network management. |
| • Concerns independent power generators have in some instances faced high risk and poor terms and conditions in securing power purchase contracts/agreements in the market. | This is the experience of IEGA members. A more liquid hedge market with contracts out 7-10 years would assist with this, as could potentially a PPA Platform. |
| • Concerns that current network charges for distributed generation do not accurately reflect the costs incurred by networks.<br>• Inconsistent terms and conditions for distributed generation to connect to the network, and the need to recognise the range of (ancillary, capacity, demand response) services it can deliver to the network. | Part 6 of the Electricity Industry Participation Code states distribution connection charges must be no more than the incremental cost of connection. The EA consulted on a proposed change and, based on feedback, decided to make no change. Decentralised generation is a focus of this government – similar to government policy when this rule was put in place in 2007 to facilitate connection of distributed generation.<br>The IEGA strongly supports work on resolving valuation of and payment for services already provided by existing small scale commercial distributed generation to their network company. It is not clear if this issue is within scope of the EA's work. |
| • Difficulties for consumers to grant access to consumption data with (non-retail) third parties, or to be serviced by peer-to-peer and retail service providers simultaneously. | This is not relevant for IEGA members |
| Coordination of policy across government | A lack of coordination of policy across government is an ongoing frustration for IEGA members. Our suggested solutions included in this (and previous submissions) are:<br>• An Expert Panel for RMA and DoC consent applications (see pages 10-17)<br>• any target in primary legislation should apply to the activities, purpose or statutory objectives of any government agency that could make decisions with climate change implications<br>• every government agency is part of the overall regulatory system and should be held to account |

[24] Page 96 – 97 of Discussion Document

| | |
|---|---|
| | to achieve the government's priorities<br>• there are multiple private and public benefits from distributed generation (see IEA table below). The mandate of some government agencies do not take into account the range of public benefits and can / have amended market arrangements that are detrimental to distributed generation. |
| Small scale of community energy advocates, and lack of networking effects | The IEGA was initially established to share technical expertise and for the last seven years has committed resource to a growing spectrum of regulatory issues. Membership is open.[25] |
| Resource Management Act barriers | IEGA feedback on these real barriers and our strongly recommended solution in the section on RMA in this submission (pages 10-17) |

The International Energy Agency (IEA) identified multiple public and private benefits of increasing energy efficiency and renewable energy use – copied below[26].

| **Multiple benefits of increasing energy efficiency and renewable energy use[1]** | |
|---|---|
| **Public benefits** | **Private benefits** |
| Employment and market growth in energy efficiency and renewables | Cost reduction, energy affordability, low energy prices |
| GDP growth | Productivity, competitiveness, product quality, employee comfort and satisfaction |
| Productivity and competitiveness | |
| Reputational benefits from reduced environmental impacts | |
| Energy system resilience and security | Reputational benefits from reduced environmental impacts |
| Reduced reliance on imported fuels | |
| Emissions reductions | |
| Improved air quality | Health and wellbeing, comfort, reduced respiratory illness |
| Reduced public health costs | |

Under the current arrangements the Authority does not consider these multiple public and private benefits in its analysis of proposed Code amendments. This might create some outcomes that are not fully aligned with the government's renewable energy target, government energy policies in total or New Zealand's international climate change commitments and targets.

[25] See website http://www.iega.org.nz/

[26] Source: Page 5 http://www.mbie.govt.nz/info-services/sectors-industries/energy/energy-strategies/consultation-draft-replacement-new-zealand-energy-efficiency-and-conservation-strategy/draft-replacement-nzeec-strategy.pdf

The Discussion Document proposes three solutions. These are discussed below.

### 9.1 Ensuring a clear and consistent government position on community energy issues, aligned across different policies and work programmes

The proposal is for a clear government position statement that would set out strategies and direction for how the sector can overcome key challenges, covering matters such as electricity market arrangements, distribution networks, the ability of local government to invest and facilitate projects, and resource management issues.

At a high level, a statement as part of the Renewable Energy Strategy about New Zealand benefiting or focusing on the decentralisation of energy and distributed energy resources within local networks or proximate to local demand without referencing scale or ownership structure and consistent with international trends, would be accurate and useful.

The IEGA is concerned to ensure small scale commercial distributed generation continues to play a role in local community resilience and well-being.

### 9.2 Enabling market access and addressing regulatory barriers

To make a practical difference in the short term the IEGA suggests government priortise simplifying the RMA DoC consent processes for generation plant of 10MW or less. On an ongoing basis government should ensure existing arrangements that facilitate distributed generation continue and a more coordinated approach across government will assist community energy as well as small scale commercial distributed generation.

### 9.3 Government supports development of a small number of community energy pilot projects

The IEGA suggests the priority should be addressing barriers for any local energy development. A community energy scheme could seek funding from the Provincial Growth Fund with one of the stated benefits being providing a template for further regional development of renewable energy resource.

If a community project is proposing to test new technologies (catalyse the early adoption of new technologies) this could be an opportunity for the National New Energy Development Centre. This could test unique options or build on international experience, for example, Denmark they have piped hot water to the houses, using waste heat from industry.

Government must be clear when ‘supporting’ a community energy pilot project who will pick up the tab of failed projects.

## Section 8.2 Encourage greater demand-side participation and develop the demand response market

The IEGA supports development of a demand-response market, building on the pilot that Transpower has been running for a number of years. Demand response has an important role to play in achieving efficient use of infrastructure. Non-firm distributed generation must be allowed to play in the demand-response market – otherwise it is discriminatory.

Transpower estimate that load control/demand response and distributed generation at about 20% of peak demand. That is, this volume has not been carried by the transmission grid because consumers have reduced their demand for electricity **and** distributed generation has generated to supply local load.

As discussed on page 18-21, consumers managing their load by electing to go on a controlled tariff benefit from lower tariffs – ie, are being compensated for this decision. With the removal of the Avoided Cost of Transmission mechanism (which incentivised distributed generation to maximise output during peak demand periods) distributed generation does not get compensated and is no longer incentivised to generate and thus reduce load on the transmission grid. IEGA believes it is bizarre that new distributed generation has to negotiate with Transpower for avoided cost of transmission payments when Transpower is a competitor to distributed generation. A member described this as a farmer with two cows trying to negotiate with Fonterra.

The IEGA has some queries about the proposal:

- By 'government' is the Discussion Document proposing MBIE develop the demand response market or the Authority?
- The proposal is for this national DR market to run alongside the wholesale market[27]. We query how this fits with the Authority's proposed Real-time Pricing project. This real-time pricing proposal includes an option for the demand side of the market to bid into or participate in the wholesale spot market. Reducing demand when it looks like there are going to be high prices will reduce the amount the consumer pays. However, distributed generation is on the same 'side' of the market as demand. If distributed generation increases output to meet peaks in demand when it looks like there are going to be high prices this will reduce the spot price but there is no mechanism for distributed generation to be paid for this service.
- Peak demand price signals are important to inform consumers and distributed generation when to reduce load / increase generation output respectively. While new distribution pricing should include these signals, the Authority's proposed transmission pricing methodology has limited focus on providing a peak demand price signal.

The IEGA agrees that a demand response market be investigated. We also support the concept of a distribution system operator which could be developed as a standard model but implemented on a regional basis – say Transpower's four transmission regions.

It is important the demand response market and DSO changes are well structured, funded and have clear objectives / outcomes within a stipulated timeframe. Transpower's demand response

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[27] Page 73 of the Discussion Document

programme has been operating for over five years but, from 1 April 2020 has no specific funding for this programme. There are other examples of similar activities that have good intentions that have not been implemented. For example, Transpower is required by the Commerce Commission's regulatory regime to consider transmission alternatives but has never signed a Grid Support Agreement with a transmission alternative.

# Appendix C: Three Case Studies

## 1. Re-consenting 0.5MW Raetihi hydro generation power station, 19 year process at a cost of over $0.5 million

**Raetihi is a small ~0.5MW hydroelectric power station located near Raetihi in the central North Island built in 1918 which has now supplied power to the Raetihi / Ohakune communities for 100 years**

**2000**: Existing resource consents expired and NZ Energy applied to have these renewed. The application for renewal included an increased water take from the streams. All but two of the consents required to operate the scheme were given 35 year consent. However, the two main water takes were only given five years as the Council determined that more information was required before granting an increase in water take.

**2007**: NZ Energy, having undertaken the extensive and very expensive further monitoring, re-applied to have the remaining two consents renewed in line with the other consents along with the additional water that was originally applied for in 2000.

From this point on NZ Energy experienced a series of extensive and prolonged delays:

- Initially the processing of the consent was delayed due to staffing issues at Horizon Regional Council. This meant Horizon breached the statutory time frames. However there were no penalties or ramifications for doing this.
- Horizon continued having staffing issues and then decided to contract out the resource consent process to a third party. This meant further delays and costs to NZ Energy.
- Then the Council decided to take the processing back in house meaning yet further delays and costs. Each time the planner changed they had to get back up to speed with our application. This resulted in a huge processing cost to NZ Energy which NZ Energy objected to as this was at no fault of our own. NZ Energy subsequently refused to pay any further processing costs.
- Horizon then took the position of refusing to process the application any further because NZ Energy hadn't paid the bill. Horizon then went as far as giving written notice to liquidate NZ Energy.
- NZ Energy objected to this and the Court ordered Horizon to continue processing the application and ordered that NZ Energy didn't need to pay any further costs and the dispute in relation to processing costs was to be sorted at the end of the application process.
- During this time Horizon had been in the process of ratifying their resource management plan (The One Plan). The plan was changed significantly during the process of submissions, hearings, appeals etc and one of these changes was the introduction of the need for discharge consents at the point of abstraction, ie. the water that runs over NZ Energy's weir. Note that this isn't for the water discharged from the tailrace but merely the residual run of the river water over the weirs. A new yet ridiculous planning rule that had absolutely no purpose in this activity. NZ Energy had the increased tailrace discharge consent approved as part of the 2002 approval and at the higher abstraction rate volumes that had been applied for but not yet granted.

- NZ Energy objected strongly against these consents as they weren't required in the 90 years previously and furthermore the residual discharge over the weirs was considered during the 2000 consenting process and deemed by the decision makers to be an integral part of that water take/structure in the river activity.
- Nevertheless, because it was a rule proposed under the revised One Plan, the rules of the RMA meant that it had to be considered. Had Horizon processed the re-application in 2007 in the statutory time frames then NZ Energy would never have been faced with this dilemma.
- This then meant NZ Energy had to lodge a new application just for the discharge consents over the weirs. Horizon then required further information on the effects of the discharges. This meant NZ Energy had to do significant further monitoring and engage further experts. The fact the scheme had these weirs in the river for 90 years were not taken into account.
- Finally after 6 - 7 years from when the 2007 re-application was made a hearing was held. However, the decision was appealed by Iwi and also NZ Energy.
- This lead to an order from the Environment Court to have all parties caucus in order to find any common ground and provide the Court their findings in advance of a hearing. The caucusing involved further expert work and also analysing water take scenarios including a scenario offered by the Court. This took a further 2 years.
- An Environment Court hearing was eventually held and the decision subsequently appealed by Iwi to the High Court. The appeal was upheld and the High Court referred the matter back to the Environment Court for a re-determination (on a point of law).
- The Environment court eventually re-issued their decision and part of that was that the parties were to agree on a set of conditions. This involved yet another prolonged process of exchanging information.

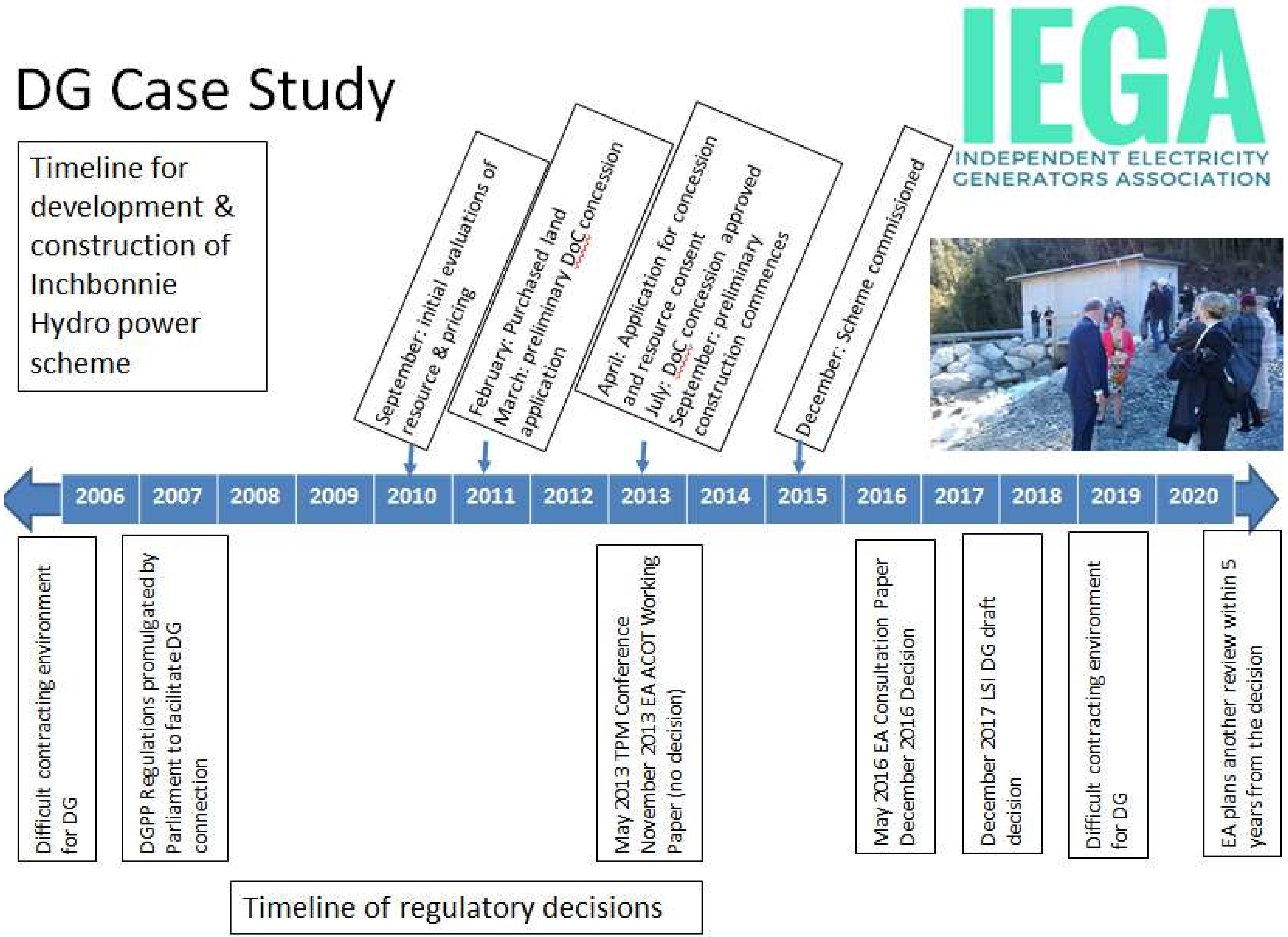
**2018**: In August the Environment court approved the conditions and the Court order sealed and the resource consent process was finished after 19 years from the date of the initial application.

The Raetihi Power Scheme has been in desperate need of a refurbishment for this entire time yet NZ Energy was unable to undertake the refurbishment until the legal consents to continue to operate the scheme were approved.

Genesis' neighbouring Tongariro Power Scheme has a capacity of 330MW. If they were to face the same degree of costs for renewing their consents then they would incur a $330,000,000 cost to renew their consents. A ridiculous thought, however a reality for NZ Energy. Clearly, de-minimus policies need to be implemented throughout local and central government in order to support small scale distributed generation.

The costs and delays mentioned above are common for consenting small scale distributed generation hydro power schemes and this doesn't take into account other processes like the Department of Conservation concession process and distribution company connection agreements.

## 2. Consenting and development of Inchbonnie Hydro power scheme



# 3. Dispute between wind farm and distribution company

This case study is a summary of an anonymised version of an Electricity Authority (Authority) determination[28] of connection charges payable under clause 4 of Schedule 6.3 of the Electricity Industry Participation Code 2010 (Code).

Part 6 of the Code provides the regulatory framework under which distributors may impose connection charges on distributed generators. Part 6 also provides a dispute resolution process for disputes between distributors and distributed generators. For the purposes of this anonymised version of the determination, the distributor is called Electricity Distribution Limited (EDL) and the distributed generator is called Tūpararā Wind Farm Limited (Tūpararā).

**BACKGROUND**

Tūpararā applied to connect a wind farm to EDL's network and used EDL's application form for connecting distributed generation for this purpose.

EDL approved the application and Tūpararā was connected under the regulated terms in Schedule 2 of the Electricity Governance (Connection of Distributed Generation) Regulations 2007 (DG Regulations).

Tūpararā's generators are asynchronous induction generators that always consume reactive power, regardless of whether they are generating or operating as a motor, i.e., consuming electricity rather than generating it.

Tūpararā's application to connect to EDL's network:

- stated the generators were asynchronous induction generators
- stated the generators consumed reactive power
- provided the generators' nameplate information
- provided engineering advice (based on EDL's network information) about the generators' simulated effect on EDL's network
- stated Tūpararā would use switched capacitors for power factor control.

Regulation 6 of the DG Regulations (subsequently, clause 6.3(2) of the Code) required a distributor to make certain information publicly available to enable connection of distributed generation where consistent with the distributor's connection and operation standards. The information the distributor had to make publicly available included the distributor's application forms and its connection and operation standards.

When Tūpararā applied to connect its distributed generation, EDL's application form and its connection and operation standards were set out in a single publicly available information pack. Before approving an application to connect distributed generation, the DG Regulations required EDL to provide information to Tūpararā regarding any conditions, requirements, or charges relating to power factor (or otherwise) that EDL wished to impose on Tūpararā:

The Authority understood that EDL approved Tūpararā's application orally. Before approval, EDL did not provide any of the required information to impose any specific conditions, requirements, or charges.

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[28] See https://www.ea.govt.nz/dmsdocument/24747-determination-of-connection-charges-payable-by-distributed-generator

After connecting Tūpararā, EDL imposed a new requirement on Tūpararā to maintain a power factor of 0.95 or greater. Failure to maintain a power factor of 0.95 or greater attracted power factor charges, based on per kvar below the required power factor.

To find an appropriate solution, Tūpararā sought advice from EDL on how EDL determined the power factor charges. Based on this advice, Tūpararā installed additional capacitors and control equipment. However, despite Tūpararā adding the further capacitors and making further control system modifications, it continued to incur power factor charges. Tūpararā asked EDL whether a joint solution was available, such as a shared STATCOM at the substation. However, Tūpararā considered EDL's indicative pricing for a STATCOM to be uneconomic. This meant that the situation continued with Tūpararā maintaining and supplementing the existing capacitor-based system, and paying power factor charges when it did not achieve a power factor of at least 0.95.

EDL then advised Tūpararā EDL would increase its minimum required power factor from 0.95 to 1.00 (unity) for Tūpararā's six highest monthly generation outputs. EDL also indicated that it would require all distributed generators on its network to adopt a higher power factor in the future. In effect, this would require distributed generators to actively export reactive power when exporting electricity into EDL's network.

Tūpararā added further capacitors and was able to achieve a power factor of 0.975. However, Tūpararā continued to incur power factor charges when its power factor fell below unity. Tūpararā became concerned that EDL's increased power factor requirements had imposed additional costs. Tūpararā considered EDL had given insufficient reasons for the new requirements and had not justified the power factor charges as a direct cost to EDL.

**DESPUTE RESOLUTION PROCESS INITIATED**

Tūpararā initiated the dispute resolution process under clause 2 of Schedule 6.3 of the Code, and wrote to EDL, disputing the basis for the power factor charges under Part 6. In EDL's view, its connection and operation standards enabled EDL to specify power factor requirements. EDL also considered that, after Tūpararā applied to connect to its network, its benchmark agreement with Transpower required EDL to maintain a unity power factor. EDL considered it fair and reasonable to require distributed generation on its network to assist in either maintaining a unity power factor on EDL's network or paying the costs of supplying the required reactive power from elsewhere.

Tūpararā complained to the Authority under clause 2(3) of Schedule 6.3 of the Code and alleged that EDL had breached Part 6 of the Code.

Tūpararā said it had tried to work cooperatively with EDL to meet EDL's changing power factor requirements. This required Tūpararā to invest in a custom-built, capacitor-based system and associated switching controls, together with upgrades to this equipment as EDL increased its power factor requirements. Tūpararā claimed that if EDL had been clear about these requirements at the time it applied to connect (as required under the DG Regulations at the time, and the Code now), Tūpararā would have had greater scope to select and install the most appropriate, cost-effective equipment at that time. EDL's unilateral changes to its power factor requirements after Tūpararā connected therefore undermined Tūpararā's original investment decisions.

**DETERMINATION**

In conclusion, the Authority determined that:

- Charges for system operation and maintenance in relation to the assets required to connect Tūpararā to EDL's network would be consistent with the Schedule 6.4 pricing principles. Charges should be based on the actual costs EDL has incurred to operate and maintain these assets since the connection of Tūpararā to EDL's network and will incur in the future. Any charges to Tūpararā should take into account any reduction in EDL's distribution network costs resulting from the connection of Tūpararā.
- The fixed daily charge and the uncontrolled energy charge that EDL invoiced to Tūpararā were inconsistent with the Schedule 6.4 pricing principles. Accordingly, EDL had to refund Tūpararā the full value of these charges paid by Tūpararā since its connection to EDL's network.
- All of the power factor charges on Tūpararā (i.e., applied when Tūpararā operated as load or operated as generation) were inconsistent with the Schedule 6.4 pricing principles. Accordingly, EDL should refund Tūpararā the full value of these charges paid by Tūpararā since its connection to EDL's network.
- Any charge for the cost of the STATCOM installed by EDL at the substation would be inconsistent with the Schedule 6.4 pricing principles. Accordingly, Tūpararā would not be required to pay for the costs of the STATCOM, and EDL should bear the full costs of the STATCOM.