To: Ministry for Business, Innovation and Employment (MBIE)

From: Todd Energy Limited

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Submission: Proposals for a regulatory regime for Carbon Capture, Utilisation and Storage

Todd Energy Limited welcomes the opportunity to provide feedback on the consultation relating to a proposed regulatory regime for Carbon Capture, Utilisation, and Storage (CCUS)

1 About Todd

Todd is one of New Zealand's largest family-owned businesses and has been part of business enterprise in New Zealand for over a century. As New Zealand's only vertically-integrated player in the natural gas market and owner of New Zealand's largest consented solar site, Todd has a unique perspective and a key role to play in New Zealand's energy transition.

Reducing emissions is a key priority for Todd and a core component of our transition strategy. In 2023, Todd set an intermediate emissions target, marking a significant milestone in our commitment to reducing emissions progressively. This target aligns with our pledge to achieve Net Zero status for Scope 1 and 2 emissions by 2045 and our commitment to be Net Zero for Scope 1, 2 and 3 by 2050.

While New Zealand needs natural gas as a transition tool, Todd Energy's gas reserves are being used up, and faster than previously thought. Gas for New Zealand is a finite resource so while there may be spikes in Todd's emissions based on our response to New Zealand's demand for natural gas, Todd is on target to reach net zero by 2045.

2 Potential to decarbonise gas processing

Todd supports the development of enabling legislation for CCUS in New Zealand and believes that CCS (carbon capture without utilisation) is a demonstrated technology with the potential to provide a valuable contribution to the decarbonisation of New Zealand's energy system. However, an enabling regime will not necessarily mean CCS investment by New Zealand's gas sector will proceed. The deployment of CCS in New Zealand will depend upon the commerciality of a project, which is driven by the abatement cost ($/tonne), carbon price, and the perceived project risk profile.

The projected decline in New Zealand's gas reserves makes the project economics for a CCS project based upon natural gas production challenging. To achieve a reasonable abatement cost from a CCS project, the volume of gas to be processed is critical as the capital expenditure of capture is fixed.

Due to the criticality of timing associated with CCS project economics, Todd believes that progressing CCS under the existing legislation is the preferred approach. By the time bespoke regulation is drafted, it will most likely be too late. Todd believes that hydrocarbon field operators can already reinject produced CO_2 into reservoirs under the existing regulations. However, Todd recommends that the government needs to publicly support CCS in depleted hydrocarbon fields and that:

1. CO_2 injection needs to be a controlled activity under the RMA;
2. The ETS settings need to be changed to allow for sequestration of third-party gas; and
3. The CMA needs to be amended to align with CCS project requirements.

If CCS is to form a part of New Zealand's decarbonisation pathway, then the division of risk and liability between a project operator and the Crown also needs to be reviewed. The relatively small amounts of industrial CO_2 projected to be produced in New Zealand make it difficult for companies to invest the considerable capital required into CCS without more certainty about commerciality. Carbon price uncertainty and ETS liability due to possible, but unlikely, leakage from storage sites are items that need to be addressed. In this regard, Todd believes that CCS projects should be considered as providing service to New Zealand's low emissions transition rather than as a robust market-led commercial venture.

3 Kapuni CCS project

Todd has been involved with the Kapuni field in South Taranaki since its discovery by Shell BP Todd in 1959. The New Zealand government established the National Gas Company (NGC) in 1967 and completed building the Kapuni Gas Treatment Plant (KGTP) in 1970. The KGTP processes natural gas from Kapuni and separates CO_2. The natural gas is distributed nationally via the transmission distribution network and the CO_2 is vented or used to produce liquid carbon dioxide for industrial use. Todd took 100% equity and Operatorship of the Kapuni field in 2017 and purchased the KGTP from Vector in 2020.

Todd has been investigating CCS to reduce emissions from natural gas processing at the Kapuni field. Through a CCS feasibility study and engineering assessment, Todd is confident that capture of CO_2 from gas processing is technically feasible and that storage of CO_2 in the Kapuni field reservoirs is technically robust because:

1. It is technically feasible using proven technologies to modify the existing KGTP and install new CO_2 capture and handling facilities.

2. The Kapuni field is a proven trap that for millions of years has contained a large gas column, and the reservoir naturally contains high CO_2 concentrations.

Using the Year End 2023 2P reserves supplied to MBIE, and a January 2027 start-up date, up to 2.7 million tonnes of CO_2 could be captured from the Kapuni field over the life of the project between 2027 and 2040 (Figure 1). The overall storage capacity of the Kapuni reservoir is much larger than this captured volume and so third-party gas could be sequestered, should this be allowed under future legislation.

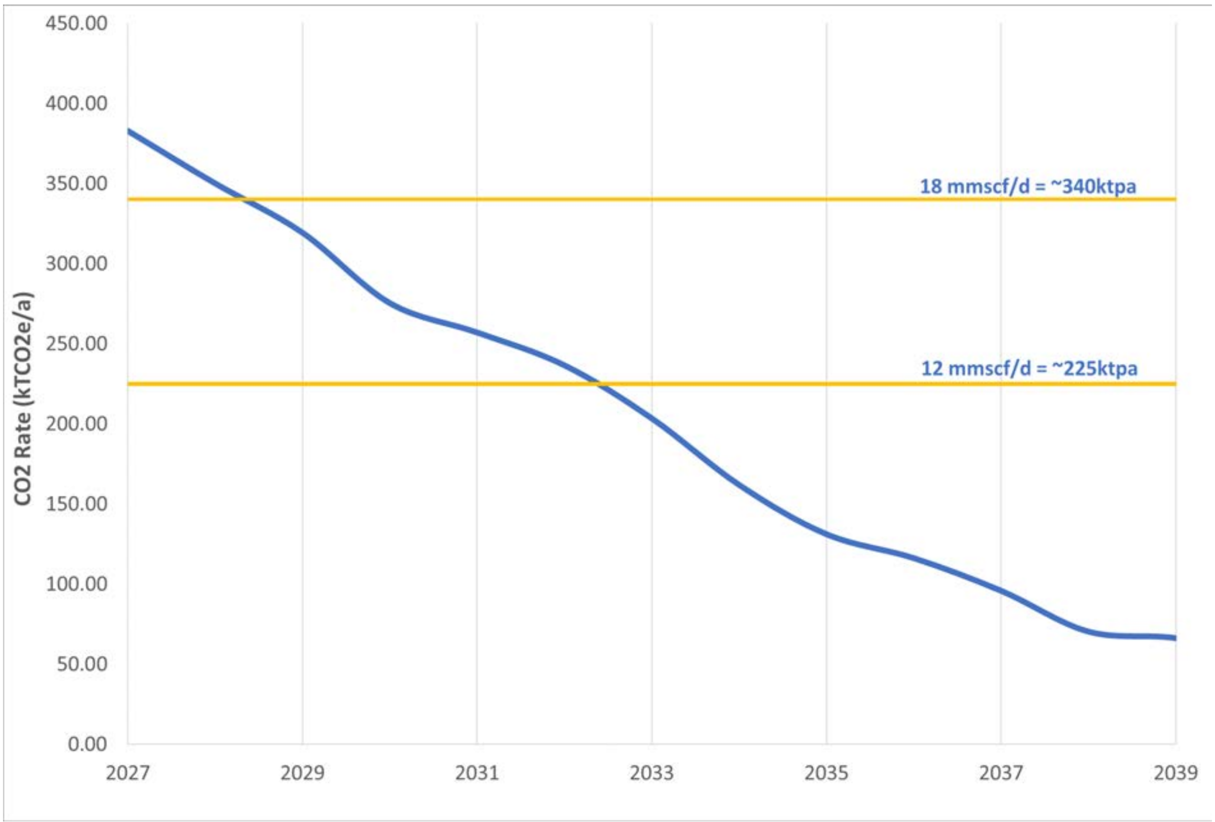

Figure 1. Indicative CO_2 production forecast from Kapuni from year-end 2023 2P production data supplied to MBIE. Orange lines represent indicative capacity of two different sized potential capture facilities

While technically feasible, a number of barriers remain to further progressing a CCS project at Kapuni.

3.1 Barriers to CCS at Kapuni

Project economic viability

CCS project economics are determined by the relationship of the cost ($/tonne price to capture and inject CO_2) to income / ETS cost avoided ($/tonne received for sequestration of the CO_2).

The cost of capture for Kapuni CO_2 is largely fixed – being the capital outlay to facilitate capture of CO_2 from the KGTP and compress it for injection. With a fixed cost, the breakeven $/tonne price is largely a function of the amount of CO_2 available for storage.

Regulatory uncertainty

Regulatory uncertainty has been, and remains, a major barrier to a CCS project at Kapuni and therefore erodes value. Todd has submitted in support of regulations to enable CCS since 2017 and advised the Climate Change Commission as part of the Heat, Industry and Power Group Technical Reference Group in 2020. Now, more than five years later, the issue has become how to introduce regulations in time to provide enough certainty to maintain a CCS project start up in 2027. In this context, Todd believes that:

1. Drafting new bespoke regulations is likely to take longer than is needed; and
2. A publicly notified consent approach under the RMA will likely delay the start up enough to make the project uneconomic.

A non-notified consent approach with National Direction from the Environmental Protection Agency would be the most efficient way to provide more certainty in project timing and provide public support for CCS by government.

There are additional regulatory uncertainties that provide barriers to CCS at Kapuni. These include:

3. Uncertainty in the ETS settings and the approach to monetise the operator's own CO_2 storage and that of third parties;
4. Uncertainty in the monitoring regime and requirements – which affects the ongoing OPEX cost and therefore viability of a project; and
5. Uncertainty in the treatment of ETS liability for stored CO_2 – ETS liability will create a barrier to investment if it resides with the operator.

In addition, the regulatory uncertainty makes a New Zealand CCS project difficult to finance, impossible to book and value storage, and problematic to insure.

4 Direct response to questions

Todd's response to these consultation questions is informed by the work we have undertaken over the last two years to assess the feasibility of CCS at Kapuni. Rather than a hypothetical desk-top response, Todd has undertaken technical analysis, subsurface characterisation and modelling, and financial assessment. This provides us a unique insight to really understand how a gas-processing based CCS project might be progressed in New Zealand.

1) Do you agree that the government should establish an enabling regime for CCUS? Please provide any further information to support your answer.

Yes, the pathway to meet New Zealand's emissions targets should be technology and fuel agnostic. This will ensure that our policy framework is best-placed to efficiently reduce emissions and eliminate barriers that might result in higher-cost abatement options. At present CCUS is at a disadvantage compared to other low-emission opportunities due to the uncertain regulatory regime.

However, timing is critical. In order for CCUS to be supported by emissions reduction from natural gas processing, the regulatory regime needs to be clarified within the next ~6 months. New Zealand's declining gas reserves and production means that potential CCUS project economics are being quickly eroded: the opportunity to underpin CCUS with existing gas production will be lost.

2) Do you agree with our objectives for the enabling regime for CCUS? Please provide any further information to support your answer.

Todd agrees with the three objectives of 1) efficient emissions abatement, 2) ensuring environmental integrity of storage sites, and 3) supporting energy security. Transition technologies, like CCUS, provide a valuable opportunity for high-emission industrial sectors to reduce gross emissions.

Globally, there is a strong case for injection and storage of CO_2 within depleted hydrocarbon fields using proven oil and gas industry technology. New Zealand is well placed for CCUS as it is fortunate to have a well-established oil and gas industry. Hydrocarbon fields in Taranaki have proven capability to trap fluids as they have retained oil and gas over millions of years. New Zealand's oil and gas sector has invested hundreds of millions of dollars to collect data, characterise these fields, and understand the subsurface. The sector also has decades of in-country engineering expertise to manage and conduct CCUS operations in a safe manner.

3) Should the ETS be modified to account for the emissions reductions achieved using CCS? If so, how do you think it should be modified?

It is Todd's interpretation of the current ETS scheme that a participant is *already* not subject to ETS liability if the removal and storage of greenhouse gas is prior to the sales meter.

Todd believes that Option 1 could *additionally* allow an ETS participant to net captured emissions off its ETS liability if the removal and storage of greenhouse gas is post sales meter.

However, Todd supports Option 2 as the overall most efficient mechanism to allow both 1) own ETS participant activity removal and storage, and 2) third party removal and storage of greenhouse gas. Option 2 ensures that CCUS is an eligible removal activity irrespective of the source of the emissions and allows for sequestration of greenhouse gas from other parties or from direct air capture.

4) Do you agree that all CCS activities should be eligible to receive recognition for the emissions captured and stored? If not, why not?

Todd, in principle is supportive of all CCS activities being eligible to receive recognition for the emissions captured and stored but highlights the following risks:

1. CCUS: If CCUS activities are developed in New Zealand there will be a need to double check that the ETS framework appropriately accounts for downstream emissions sources such as those from syn-fuels produced. Noting the breadth of the ETS this may be a low-risk issue, but there may be cases where a technical amendment to the ETS is required to ensure the downstream emission source is an eligible activity.

2. Direct air capture (DAC): CCS in New Zealand will initially focus on emission streams that are generated in New Zealand and are already included in the ETS. In contrast, DAC will be sequestering ‘global’ emissions and forms an essentially unlimited pool of sequestration potential. This has the potential to create a similar challenge as seen in the forestry sector where there is a risk of creating an oversupply of NZUs. This potential mismatch between supply and demand would dampen NZU pricing. Current DAC cost estimates suggest this risk is presently small, but highlights the need to clarify the role of international carbon trading in the NZ ETS.

If the ETS is modified it will be important to consider similar ETS schemes abroad. With the potential for international trading in the future, it will be important that our approach is compatible with other ETS schemes that New Zealand may wish to link to.

5) Do you think there should be a separate non-ETS mechanism for providing economic incentives for CCS? If so, what would this mechanism be?

Todd generally considers the ETS to be the best mechanism to provide economic incentives for emissions reductions. However, if New Zealand believes that CCS is a strategic component of our transition by reducing emissions at a large point-source, then Todd would suggest that other non-ETS mechanisms be considered.

There are many alternative methods for providing economic incentives for a strategic CCS project. Probably the simplest and most efficient method would be to provide a fixed $\$/tCO_2$

sequestration contract for a tranche of gas to underwrite a project and remove the volatility of the ETS. Any sequestration above this tranche could be made subject to the ETS.

This would have the advantage to New Zealand of providing a clear path to up to ~3 million tonnes of gross CO_2 removal at source, provides an opportunity for further third-party CO_2 capture and emissions reduction, and could help meet New Zealand's 2050 emissions reduction targets domestically.

6) In your opinion, which overseas standards for monitoring, verification and reporting of CCUS-related information should New Zealand adopt?

In Todd's opinion it is most important that any measurement, monitoring, and verification (MMV) requirements are risk-based, site-specific, and adaptive. There is no 'one size fits all' solution to monitoring CCS projects and different technologies work in different settings – an offshore monitoring programme will look very different to an onshore programme, for example.

It is also important to note that Todd views depleted hydrocarbon fields as very different to "greenfield" sites for CCS projects. Hydrocarbon fields have:

1. Proven capability to trap fluids as they have retained hydrocarbons of millions of years.
2. Millions of dollars already invested in data collection and subsurface analysis.
3. Typically, many years of production to calibrate the reservoir behaviour.
4. Generally low pressure from production depletion creating proven storage potential.

Therefore, depleted hydrocarbon fields have a very different risk profile in comparison to new sites that are poorly understood. With a risk-based process these considerations will be incorporated into robust MMV plans that will vary from project to project.

In assessing CCS feasibility in New Zealand, Todd has looked towards ISO standard ISO27914:2017 for guidance. It is up-to-date, technically inclusive, and an operationally practicable standard for CCS. It is our understanding that Australia has also adopted this standard.

7) Is there any other information that CCS project operators should be required to verify and report? Please reference the relevant overseas standards where applicable.

Todd believes the requirements are well captured in ISO 27914:2017. Todd would recommend avoiding bespoke New Zealand MMV conditions unless they are necessary for the application of existing legislation. This avoids potential issues with obtaining international insurance and finance requirements, and the potential for international trading in the future.

Todd believes that one agency should ideally have oversight of CCS projects to prevent conflicting MMV plans and inefficient reporting requirements.

8) What methods should be used to quantify CO_2 removal and storage in CCUS projects?

For CCS projects this is generally covered in ISO 27914:2017 (sections 8.5.2.1 and 8.5.2.2).

For CCS projects with removal and storage of greenhouse gas prior to the sales meter, not subject to ETS liability, quantification of CO_2 volumes removed and stored is less critical from a financial perspective. Although fugitive emissions still need to be considered.

For NZU credits under Option 2, the gas removed and stored needs to be accurately metered prior to injection whether for operator or third-party CO_2 sequestration. If injected deep underground into depleted hydrocarbon reservoirs all the gas can be assumed to be stored unless monitoring shows otherwise. Recycling of CO_2 in gas fields through ongoing production should be easily accounted for using CO_2 content of the gas produced.

CCUS schemes involving the utilisation of CO_2 are more difficult to assess and may need to be reviewed on a project-by-project basis. In enhanced oil recovery projects, for example, the CO_2 is usually recycled during oil recovery and is ultimately left underground at the end of the project ensuring that it is permanently stored. The utilisation of CO_2 for other applications may be different and subject to different assessment. Paying for CO_2 to be captured and utilised in syn-fuels before they are exported and the emissions released overseas needs to be avoided, for example.

9) Are additional mechanisms required to ensure compliance with monitoring requirements?

The mechanisms required to ensure compliance with monitoring requirements will depend upon the regulatory framework used. Todd believes the current consent process under the RMA is fit for purpose to manage this.

10) What level of transparency and information sharing is required?

The level of transparency and information sharing may depend upon the regulatory framework used. The RMA has annual reporting requirements for discharge consents which already become open file.

Todd generally believes that demonstration of compliance to international standards and transparency of emissions reductions will increase public confidence in carbon capture and the security of CO_2 storage.

11) Do you consider there should a minimum threshold for monitoring requirements so that small-scale pilot CCS operators would not have to comply with them? If so, what should be the threshold?

If a small-scale project is claiming ETS relief then it should be subject to the same process of assessing monitoring requirements as a full-scale project. In-line with ISO 27914, monitoring requirements should be dictated by a risk-based assessment of the site and project: if a project has risk outcomes assessed to be of lower likelihood and severity, then monitoring requirements should be correspondingly less intensive than higher risk projects.

12) Should a monitoring regime extend to CCU activity?

Given the proposed approach to a monitoring regime is based upon carbon capture and sequestration regulations it is unclear how this could be applied to all utilisation technologies. If the CO_2 is ultimately tapped in the subsurface, such as CO_2 utilisation for enhanced oil recovery for example, the same monitoring regime could be extended. Utilisation for applications such as syn-fuel production, which do not result in ultimate underground storage, would need different requirements. These usages of CO_2 could presumably be covered by other areas of the ETS.

13) Do you agree the proposed approach on liability for CO_2 storage sites aligns with other comparable countries (like Australia)? If not, why not and how should it be changed?

Yes, the proposed approach to liability for CO_2 storage sites aligns with other comparable countries. However, due to the challenging commercial conditions for a CCUS project in New Zealand, the allocation of liability to operators engaging in CCUS needs to be carefully considered else it will prevent the development and implementation of CCUS. This is further addressed in Question 14.

14) Is the proposed allocation of liability consistent with risks and potential benefits? Are there other participants that should share liability for CCS operations?

CCS provides a valuable opportunity for New Zealand to help decarbonise the transition to a lower emissions economy. This will result in lower New Zealand and global emissions, and a cleaner domestic energy supply. Whilst, aside from ETS relief, the benefits are communal for New Zealand, the risks and liabilities for the project are proposed to be borne solely by the CCS operator. Given that CCS project economics are marginal, this is currently a detriment to deploying the technology in New Zealand.

For a CCS scheme underpinned on capture of CO_2 from gas processing, such as Kapuni, the operator is exposed to the following material commercial risks:

1. Appraisal and production of natural gas. If the reserves are not there, the cost of sequestration \$/tCO_2 will increase. Thus the operator is subject to the risk of higher appraisal and production costs, higher sequestration costs, but lower revenue.

2. Uncertain carbon price. The revenue from sequestration is dependent upon the NZU price. New Zealand has seen large fluctuations in the price of carbon due to ETS settings.

3. Uncertain financing costs.

4. Risk of migration and leakage of CO_2 from a storage site, with the operator potentially incurring the cost of surrendering NZUs.

5. If the operator is paid to sequester third party CO_2, the uncertainty as to who may be responsible for leakage of that gas.

There is a limited volume of CO_2 available for sequestration in New Zealand to provide revenue to offset these risks. Therefore for CCS to proceed in New Zealand Todd believe these risks and liabilities need to be more evenly apportioned. A wider spread of liability would better reflect the communal benefits of sequestration to New Zealand.

Todd suggests considering:

6. Reducing the carbon price uncertainty for a CCS project. This could be done with a fixed \$/tCO_2 sequestration contract for a tranche of gas to underwrite a project, rather than using the ETS scheme, if it is considered key to New Zealand's emissions reduction strategy (as outlined in Question 5).

7. No liability of paying back NZUs for CO_2 leakage once it has entered a storage reservoir. The potential scale of this liability for the operator, for an event that is highly unlikely to occur, is a barrier to investment. The development of a CCS project requires significant up-front work to ensure that the leakage risk from a storage project is acceptably low prior to injection, and that an appropriate monitoring regime is in place. This puts the onus on the Crown and operator to ensure that risks are appropriately managed to ensure there is a small potential for significant leakage prior to proceeding with the project, noting that under the current proposal, the Crown ultimately indemnifies the storage site in any case.

   The operator would still be liable under usual RMA or CMA rules for any remediation work that could be done to prevent the leak during the injection period (i.e. if it is from a leaking suspended well or injection well) or risk having the injection permit revoked. The risk of having a project shut down should still be enough to encourage adequate due diligence and characterisation of storage site prior to injection. The operator would still be liable for leakage during transport and injection.

8. If the operator is not liable for paying back NZUs for CO_2 leakage from the reservoir then third-party gas sequestration becomes much more commercially reasonable. Third party CO_2 sequestration would also help provide some potential mitigation for low-side appraisal and production of natural gas outcomes.

With regards to point 7 it should be noted that this is an area where others have provided detailed perspective. The Global CCS Institute provide a Thought Leadership piece in 2019 titled "Lessons and perceptions" Adopting a commercial approach to CCS liability" which may be of use. They highlight the "*these liabilities present some unique challenges"* including the "*practicality of coupling climate change liabilities to the provision of financial security effectively linking liability to the uncertainty of pricing under an emissions trading scheme".* Therefore, as long as the government is in agreement that the sequestration site is appropriate, and the operator is prudently following the permitted injection and MMV plans, it seems that there is little to be gained from adding this additional liability. The only impact is likely to discourage investment through creating a potentially existential risk to a company.

For operators, the much lower risk alternative is to pay the ETS price and the liability is discharged immediately without future risk or uncertainty.

Reviewing the suitability of storage sites and the suitability of MMV programmes can be supported by organisations such as CO2Tech, which is a commercial spin-off from the Australian CO2CRC project undertaken by CSIRO.

15) Should liability be the same for all storage sites if projects are approved? Or should liability differ, depending on the geological features and characteristics of an individual storage formation?

If a project is claiming ETS relief then it should be subject to the same liabilities as other projects and there should be consistency of approach. As discussed in Question 14, Todd believes that once the government agrees that a storage site is suitable, an operator should not be held liable for leakage.

In this regard Todd believes that Kapuni is an attractive storage site. The field has a proven trapping mechanism, large storage capacity, and has already had >500 bcf of high CO_2 gas reinjected into it. The field has produced ~2 trillion cubic feet of gas while the forecast is only for 50 billion cubic feet of CO_2 gas storage. Therefore this seems like a very low risk project.

Storage projects in other depleted hydrocarbon fields and green-field sites should have adequate investment in characterisation prior to project progression. Then the leakage risk can be appropriately assessed and deemed acceptable, or the project stopped.

16) Do you consider there should a minimum threshold for CCUS operators being held responsible for liability for CO_2 storage sites so that small-scale pilot CCS operators would be exempt? If so, what should be the threshold?

If a small-scale project is claiming ETS relief then it should be subject to the same liabilities as a full-scale project within the context of New Zealand. However, in order to encourage the uptake of CCUS in New Zealand, liabilities need to be appropriately apportioned as outlined in Question 13.

The scale of CCUS development in New Zealand is likely to be substantially smaller than many international CCUS facilities. Chevron's Gorgon project in Australia, for example, is estimated to reduce emissions by over 100 million tonnes over the life of the project. Santos's Moomba project in Australia is expected to sequester 1.7 million tonnes CO_2e per annum. Given the much larger amount of CO_2 available for sequestration and the longer timeframe of these international developments, operators have much greater revenue and therefore flexibility to accept more liability.

17) Should the government indemnify the operator of a storage site once it has closed? If so, what should be the minimum time before the government chooses to indemnify the operator against liabilities for the CO_2 storage sites?

Due to the nature of storing CO_2 in the subsurface the liability will, in the long term, return to the Crown. The Crown owns the subsurface and Crown Minerals Estate, and companies are generally ephemeral in comparison. For CCS to be acceptable to operators and the public, long-term or perpetual liability is not an option and the Government should provide indemnity to the operator (make exempt from loss or damages) once a site is closed.

As part of hydrocarbon field abandonment, it is required that wells should be plugged and abandoned with isolation/barriers established via "Acceptance Criteria" and verified under the Well Examination Scheme by an external, independent, and competent person. As a depleted hydrocarbon field this abandonment process would apply to a Kapuni CCS project. Todd would suggest a similar abandonment process be applied more widely to CCS projects to reduce the risk of leakage post-closure.

Todd would suggest a period of five years following cessation of CO_2 injection is reasonable. Five years aligns with existing discharge consents for deep well injection (DWI) from Taranaki Regional Council. As in other jurisdictions, Todd envisions that a MMV programme would incorporate a post injection plan to cover this period. That plan would likely ramp down in scope and frequency in the post injection period, but would address the main risks to ensure that a safe and sound sequestration site remains. This should be enough time for the operation to have shown itself to be free from any significant risk of leakage.

18) Are additional insurance mechanisms or financial instruments required to cover potential liabilities from CO_2 leakage in CCS projects?

As outlined above, Todd does not believe that leakage of carbon stored in the subsurface should be subject to ETS liability.

If operators are required to carry insurance for such liabilities it is critical that insurance cover is available on commercially reasonable terms and consistent with what is available in the insurance market. This will ensure that insurance does not become an obstacle to investment in CCS projects. On this basis, Todd encourages MBIE to engage early with industry participants and the insurance sector to develop a good understanding of the risks involved in CCS projects and understand to what extent the risks will be insurable.

For operators of hydrocarbon fields, the remaining insurance requirements for drilling, well intervention, and plant maintenance and integrity activities are likely to be similar to that held already.

In general, the more closely aligned New Zealand is with international standards and approaches, the easier it will be to obtain insurance and other financial products from the relevant markets.

19) What measures should be implemented to monitor CCS projects for potential leakage and ensure early detection?

This should be addressed by the project specific MMV plan as outlined above. It is most important that any MMV requirements are risk-based, site-specific, and adaptive. There is no ‘one size fits all’ solution to monitoring CCS projects. This is covered in ISO 27914:2017.

20) Do you agree that trailing liability provisions are needed? How do you think they should be managed?

For CCS in depleted hydrocarbon fields, we believe that trailing liability provisions for decommissions are already covered by the CMA.

For permitting green-field sites, it depends upon the mechanism used for permit award. If the CMA is used to allow for exploring and appraisal of CO_2 injection sites and CO_2 injection activities, then decommissioning liability will already be covered.

Todd believes that ETS liability for storage leakage should not apply and so trailing liability for CCS projects should also not apply.

21) Are inconsistencies in existing legislation for consenting and permitting impacting investment?

Yes, although project commerciality is also problematic.

Uncertainty in whether bespoke CCS regulation will be introduced, how CCS in depleted hydrocarbon fields will be treated under the CMA, the lengthy and uncertain RMA and appeals process, and the ETS settings and treatment of removal activities all create large uncertainty. It is difficult to make a robust investment case for a CCS project given this lack of clarity.

Resource Management Act (RMA)

New Zealand needs a supportive consenting framework to enable CCS and Todd supports the sentiment that a more straightforward consenting regime is required, with longer consents. The RMA is in the midst of radical change and we are concerned that the consenting process through the new legislation will make it impossible to design and build the required infrastructure in the time frame required. The new regime is not yet in force, so is currently untested, but it is not expected to facilitate the fast-tracking of much needed energy infrastructure due to the ability for activist individuals or groups to stall the process through exercising appeal rights. The current RMA presents considerable consenting process issues, including timing and appeal rights.

22) Should the permit regime for CCUS operations be set out in bespoke legislation or be part of an existing regulatory regime (such as the RMA, EEZ Act, the CMA or the Climate Change Response Act 2002)? Please give reasons for your answer.

It is not yet clear whether CCS is going to be economic for New Zealand. Given the decline in New Zealand's natural gas production it is imperative that CCS projects underpinned by gas processing become operational quickly, otherwise there will be insufficient remaining CO_2 to make projects commercially viable. Therefore, Todd believes it would take too long to enable any bespoke legislation and instead the Government should look at clarifying the path under current legislation.

Todd believes that operators can already reinject produced gas and CO_2 into field reservoirs under existing regulations. However, the existing regulations can be clarified and consideration needs to be given to how CCS activities interact between the RMA, CMA, and ETS. Clarification is also needed about who is the "lead" agency in this framework to allow for efficient oversight and reporting. Examples of some additional considerations of using the existing regulatory framework for CCS are as follows:

RMA

1. A publicly notified consent approach under the RMA would likely delay the start up enough to make a CCS project at Kapuni uneconomic. Therefore, Todd believes that a non-notified consent approach with National Direction from the EPA would be the most efficient way to provide more certainty in project timing and provide public government support for CCS.

2. The MMV requirements under the RMA should be clarified and agreed so that project economics can be accurately modelled and so that there is up-front and durable agreement on what is required. The MMV requirements need to be fit-for-purpose, site-specific, and adaptive while being pragmatic so that additional cost burdens to the project are minimised.

3. Will a CO_2 injection discharge consent only be allowed in a CMA permit? How will this work for greenfield sites?

4. The interaction of the RMA with CMA at end of field life needs to be clarified: extension of discharge consents and MMV plans if field life is extended etc.

CMA

5. The primary purpose of mining permits is to permit the extraction of minerals, including petroleum. The CMA generally would not apply to the injection of pure CO_2 (i.e., not mixed with hydrocarbons) as it does not meet the definition of 'petroleum' in section 2. Therefore, any injection of pure CO_2 at a stand-alone site that does not directly occur a result of petroleum mining from the same site would appear to not trigger any requirements under the CMA as there is no nexus to petroleum mining activities.

6. However, where the injection of pure CO_2 occurs as a result of petroleum mining activities within the same site (for example, as anticipated at Kapuni), it appears that the CMA will generally apply to relevant wells and infrastructure, primarily, decommissioning, financial security, and post-decommissioning obligations.

Taking Kapuni as an example, it is likely that when petroleum mining activities cease the injection of pure CO_2 would also cease. Usual decommissioning obligations would arise so the CMA in its current form would appear to be appropriate.

7. However, it is not clear how the CMA would apply in the situation where the injection of pure CO_2 continues to occur after petroleum mining activities have ceased, for example, if the permit holder continues to inject pure CO_2 for a third-party provider of CO_2, (e.g. another permit holder).

Whilst there is the ability to apply for Ministerial discretion under the CMA to delay the decommissioning of some infrastructure and wells, some certainty would be preferred, including:

a. The permit surrender process, i.e., could the permit be surrendered as it relates to petroleum mining but other CMA obligations retained as it relates to decommissioning, financial security, etc?
b. How decommissioning of relevant CO_2 injection infrastructure will be dealt with.
c. How financial security will be managed between decommissioned petroleum mining infrastructure vs remaining CO_2 injection infrastructure.
d. Any post-decommissioning obligations.

8. Liability of the stored CO2 needs to be clarified, but the CMA may not be the best place for that.

9. Reporting requirements for CO_2 injection activities need to be clarified – is it through the discharge consent provided or through the CMA? What needs to be reported and to whom?

10. Site monitoring activities also need to be distinguished from prospecting activities. At the moment it is not an entitlement to collect subsurface data in adjacent permits. This might be a requirement for CCS monitoring.

ETS

11. ETS settings need to be modified to allow for removal activity and provide incentive for third parties to sequester their CO_2.

12. ETS settings need to be durable to provide more certainty in the forward carbon price.

13. Todd believes that once stored underground, CCS operators should not be liable for CO_2 leakage under the ETS, as outlined in Question 14.

Using current regulations, long-term regulatory certainty is also required. Given the extent of Government policy and regulatory change across election cycles, and the impact it can have on making investment uncertain or uneconomic, the Government should consider underwriting the risk of future Government policy or regulatory changes materially negatively impacting the economics and overall viability of such investments. Any CCS operator needs a level of assurance around the policy and regulatory settings to make any such investment.

23) Should CCS project proponents be required to submit evidence that proposed reinjection sites are geologically suitable for permanent storage, in order for projects to be approved? If so, what evidence should be provided to establish their suitability?

Yes, as per ISO 27914:2017 standard and outlined above.

24) Should there be separate permitting regime for CCU activity if there is no intention to store the CO_2?

If there is no storage of CO_2, then this is not a removal activity. Therefore, the emissions should be considered under the ETS.

If this question refers specifically to subsurface storage, then other types of storage such as high CO_2 cement production should be treated differently, although still considered as removal activities under the ETS if appropriate.

25) Are there regulatory or policy barriers to investment and adoption of CCU technologies?

As noted in the consultation document, Todd Energy's Kapuni plant is currently the only domestic manufacturer of liquid CO_2 in New Zealand. With respect to utilisation of CO_2 for industrial applications e.g. production of food grade CO_2, we do not believe there are regulatory or policy barriers to investment and adoption of CCU as evidenced by the continued operation of the Todd Energy Kapuni plant.

26) What potential markets for CO_2 derived products do you see as most critical in New Zealand?

Liquid CO_2 is an important industrial product that is already produced at Kapuni. This will use between 5-10% of the total produced CO_2 from the Kapuni field over the duration of the field life (Year End 2023 2P reserves) and is compatible with the sequestration project.

27) Are there any specific barriers to transportation of CO_2?

Todd produces liquid CO_2 at Kapuni and has not identified any barriers to CO_2 transportation under the existing regulations.

Whilst some international CCUS projects are transporting CO_2 by road / rail / sea tankers, this has not been considered for Kapuni CCS. Re-utilisation or installation of new dedicated pipelines for CO_2 are the most likely intra-field or inter-field transportation solution.

The New Zealand technical standard, NZS / AS 2885.1 provides guidelines for the design and construction of pipelines for CO_2 transport. This standard acknowledges certain aspects of CO_2 pipeline design are subject to ongoing research, however there is sufficient guidance available for an operator to successfully execute a CO_2 pipeline installation (or conversion) in New Zealand.

Todd has investigated the feasibility of converting various natural gas pipelines to supercritical and gaseous CO_2 transportation service. The conversion of an existing pipeline asset to CO_2 service must be considered on a case-by-case basis. Due to the physical properties of CO_2, it is likely that many existing natural gas pipelines are un-suitable for conversion to CO_2 transportation service (or would require substantial capital investment to convert service). It should not be assumed that the presence of an existing pipeline or pipeline network will offer an economically viable transportation solution for CO_2.

Barriers to supply of third-party gas to a CCS site from third party industrial emissions are mainly economic – the cost of capture, CO_2 purification, compression from atmospheric pressure stacks, and transportation – rather than regulatory.