fracking inquiry

From: Stonier, Stephanie [redacted]
Sent: Sunday, 25 February 2018 3:46 PM
To: fracking inquiry
Cc: origin_nt_beetaloo; Close, David
Subject: Origin Submission - Panel Hearings (Round 3)
Attachments: 180225 Attachment 1 - Origin Response to Panel Hearings (Round 3) (Final).pdf

Dear Justice Pepper and Panel Members, NT Inquiry

Please find attached Origin's Submission pertaining to information requested and / or discussed during the final round of the Inquiry's Panel Hearings.

Please feel free to contact us should you require any additional information or clarification with regards to the attached.

Regards

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Origin Energy

Provision of Information to the Northern Territory Scientific Inquiry into Hydraulic Fracturing - Post Round 3 Panel Hearings (February 2018)

DISCLAIMER : All Origin comments and / or representations in this document pertain only to its shale gas exploration project in Australia's Northern Territory

Version	**1.0**
Submitted	**25 February 2018**
Presented by	**Origin Energy**

Contents

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Reference Attachment(s)

1 Information Provision - Commitments to the NT Inquiry Panel

During Origin's appearance at the final round of Public Hearings held in February 2018, Origin committed to follow up on the following questions and / or requests for information.

1.1 Origin's View of Recommendations - NT Inquiry Draft Final Report

During Origin's appearance before the Panel, the question was put to Origin as follows.

<u>Question</u>

Can the Panel assume that if Origin has not formally responded to a recommendation in the Draft Final Report, then it is the case that Origin accept and support the recommendation?

<u>Response</u>

Origin advised the Panel that that assumption is incorrect and Origin made a commitment to provide a response to each Recommendation. Statement A and Statement B contain Origin's response and / or feedback and / or suggestions pertaining to each recommendation in the Draft Final Report.

1.2 Origin's View on Recommendations - Social Impact Report(s)

<u>Question</u>

Can Origin provide a response / position on the recommendations contained in the Social Impact Assessment / Framework Report?

<u>Response</u>

Statement C is Origin's response and / or feedback and / or suggestions pertaining to each recommendation and principle relating to the Independent Social Impact Assessment reporting.

1.3 Industry participation initiatives / examples relating to host Traditional Owners and local community

Question

Can Origin provide examples of employment programs / community initiatives that demonstrate how the company would seek to maximise local benefit and participation in their activities?

Response

Origin's core principles to yield maximum local benefit and participation include:

- primary stakeholders, directly impacted by hosting Origin's natural gas extraction activities, that is, host Traditional Owners and host Pastoralists, will continue to participate directly in elements of project design, planning and execution and will continue to receive statutory and additional benefits as project partners. Secondary, albeit parallel engagement benefit will also extend to include the local, regional and NT communities more broadly.

- future initiatives and programmes will be co-designed, and agreed with directly impacted stakeholders and will be encapsulated into legally binding agreements. For example, in a future Production Agreement with host Traditional Owners and Access Agreements with host pastoralists;

- contributing positively to regional economic development is considered critical to establishing purposeful partnerships with communities to deliver tangible and collective benefits. At the correct time in the project's lifecycle, Origin has committed to working collaboratively with local and State government and agencies to optimise collective benefit. Examples of collective benefits may include, though are not limited to;

  - shared infrastructure improvements
    - roads;
    - airstrips;
    - telecommunications; and
    - community and emergency services.

  - acceptable and agreed increases in residential workforce numbers, who, with their families, in turn contribute to the local and regional economies;

- establishment of a business and employment portal or facility to ensure communities have consistent and credible access to information relating to opportunities associated with:
  - training and work ready pathway opportunities;
  - employment opportunities;
  - contracting and procurements opportunities; and
  - 'new' industry opportunities;

  an example of a potential partnership opportunity would be to work with Aboriginal Ranger groups to support the resourcing of dedicated teams who would be able to provide independent and participatory monitoring services for ongoing contracts such as:

  - weed monitoring and management;
  - fire control and management;
  - noise monitoring;
  - dust monitoring;
  - water monitoring, to name but a few.

To deliver on the above commitments, Origin will seek to maximise local, regional and NT opportunities by:

- forecasting jobs, and identifying early, the applicable training, qualifications, and skills required to be competitive in securing those opportunities and, where necessary, establish programmes to assist in obtaining the necessary training and skills - be it by way of apprenticeships, scholarships, job ready programs etc;

- forecasting project spend, goods and services to allow NT businesses to prepare to competitively secure those future contracts. A current, albeit early example of new industry / business opportunities is in the areas of waste management and sand / proppant contracts. Origin has reached out to several Aboriginal businesses to secure sand samples so we may have them laboratory tested to ascertain their compatibility for stimulation activities. Early identification of these type of opportunities, well in advance of full scale development, will allow potential suppliers to ramp up their business to meet the forecast demands of any future project development activities;

- purposefully and proactively working with stakeholders to ensure that our contributions align with community objectives and initiatives. That we do not intervene with our own ideas of suitable programs, rather we collaborate with communities to design 'fit-for-community initiatives' that are owned by the community and led by the community, supported by companies operating in their area of influence; and

- establishing internal hard local procurement and employment targets.

1.4 Gas Composition from Amungee production test

Question

Can Origin please advise the composition of the gas from the Amungee production test?

Response

At Statement D, we have provided Origin's Certificate of Analysis from SGS Certified Chemists.

1.5 Composition of Amungee flowback fluid / water

Question

Can Origin please advise the composition of the flowback water / fluid from the Amungee well that was fracture stimulated in 2016.

Response

The composition of the flowback water / fluid from the Amungee well is contained in the Human Health Risk Assessment (HHRA), completed by a third-party expert, for the Amungee NW-1H stimulation, in Origin Submission Number 466 to the NT Inquiry.

2 Provision of Information of Interest identified during the final round of Panel Hearings

2.1 Convention and Unconventional

Despite the NT Inquiry Panel providing an explanation of the difference between conventional gas and unconventional gas in their *Background and Issues Paper* published on 20 February 2017 and the *Draft Final Report* published on 12 December 2017– the terms conventional and unconventional continue to be misused and misunderstood in the community more broadly.

This was again evidenced during presentations and subsequent question(s) and / discussion(s) on this topic during the final round of public hearings and community meetings. It is Origin's view that there remains considerable confusion and misunderstanding on the use of the terms conventional and unconventional as they relate and pertain to natural gas extraction.

During the final round of Panel Hearings, presenters for both the Arid Lands Council and Drs for the Environment talked about the Mereenie gas field as being a positive project / development. Declaring that natural gas was good for reducing carbon emissions; and that local Traditional Owners working at the project and / or participating in the project are happy with the project and the extraction process. Both presenting organisations remained in opposition of the same extraction activity being utilised elsewhere in the Northern Territory as they stated to believe that Mereenie was *conventional fracking* (support) as opposed to u*nconventional fracking* (oppose).

We seek to take a moment to reiterate that industry does not recognise the terms used of *conventional fracking* and / or *unconventional fracking*.

The NT Inquiry's *Background and Issues Paper* and *Draft Final Report* both explain that the use of the terms conventional and unconventional are used to describe a type of gas reservoir. That is - conventional describes gas plays where the natural gas or hydrocarbons have migrated from their source (the source rock) and have travelled through permeable layers above until it ultimately becomes trapped by an impermeable natural rock barrier (impermeable rock formation). This typically is true for describing onshore and offshore conventional gas plays such as Mereenie and Black Tip. Unconventional shale reservoirs describe plays where the source rock remains the host rock, that is, the natural gas or hydrocarbons have not migrated from their original source – they are trapped in the same formation that they have been formed in. This is the case for the Velkerri and Kyalla formations in the Beetaloo Sub-basin. Figure 2.1 below seeks to illustrate the differences between conventional and unconventional natural gas reservoirs as they are described above.

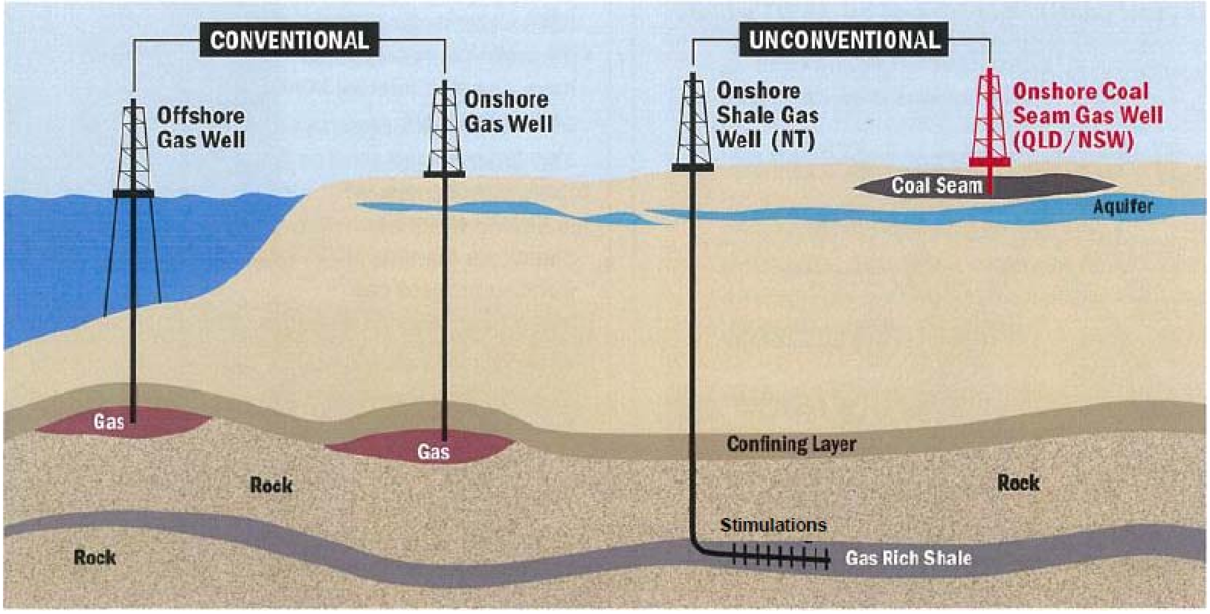


Figure 2.1 – Conventional and Unconventional Gas Reservoirs

It is difficult to find the source of the misinformation about conventional fracking and unconventional fracking - and how it has become such a common misconception within the broader Northern Territory community. Origin respectfully requests that the Panel consider how it may be appropriate to correct this common misunderstanding by giving it prominence in its *Final Report.* That is, that the terms do not describe the extraction process of hydraulic fracture stimulation which can be the same technical process in both conventional and unconventional onshore gas reservoirs. Correcting or clearly stating this element of misinformation is considered critical by Origin as it appears to be at the heart of distress and concern amongst the community.

2.2 Exploration and Appraisal Activity

Origin has maintained and evidenced throughout the NT Inquiry process that small scale exploration and appraisal activities can be safely executed and that activities should be permitted to continue during the forthcoming period of improvements to the NT regulatory framework. During the final round of Public Hearings and Community Meetings, misunderstanding or misalignment existed as to the level of activity during Exploration and Appraisal.

To support the Panel in assessing and contemplating recommendations in this regard, Origin sets out below the exploration work currently being contemplated for the next three years.

2018	Zero (0) new wells to be installed (drilled)
	Engineering and civils / infrastructure work required for 2019 activities
2019	Two (2) to four (4) wells to be installed (drilled and stimulated)
2020	Two (2) to four (4) wells to be installed (drilled and stimulated)

In outlining the above activity level(s), we consider it important to highlight that in Origin's submission dated 30 April 2017 – in response to the NT Inquiry's *Background and Issues Paper* - we provided information at Chapter 3 *(Exploration work to date and national development scenarios).* In this submission, information was provided in the context of assisting in articulating the slow pace and steady nature of activities through each phase leading up to a potential development. Such a notional development scenario was deemed necessary and appropriate in order to assist the Panel in being able to purposefully identify and assess risk anchored in a notional and plausible level of activity from exploration, appraisal, delineation through to development (options provided being small-scale and large-scale).

2.3 Baseline Water Monitoring (Before, During and After Hydraulic Fracture Stimulation)

In Origin's submission dated 30 April 2017 – in response to the NT Inquiry's *Background and Issues Paper*, Origin provided information at Chapter 4 *(Risk Theme 1: Water)* about groundwater and groundwater baseline monitoring.

Origin commenced a ground water monitoring program in 2014, prior to exploration activities being commenced. Origin described that the water monitoring network included over 30 water bores which are located within proximity to proposed activity to ensure localised monitoring and early detection of any fluctuations and / or changes to baseline conditions. Origin understood the importance of the early establishment of a robust and activity-applicable water monitoring network, focussed on monitoring potable water from the Cambrian Limestone Aquifer - commonly referred to as the Tindal Aquifer, which is the region's most frequently accessed and / or utilised aquifer for domestic use as well as for use by the agricultural, tourism, mining and pastoral industries.

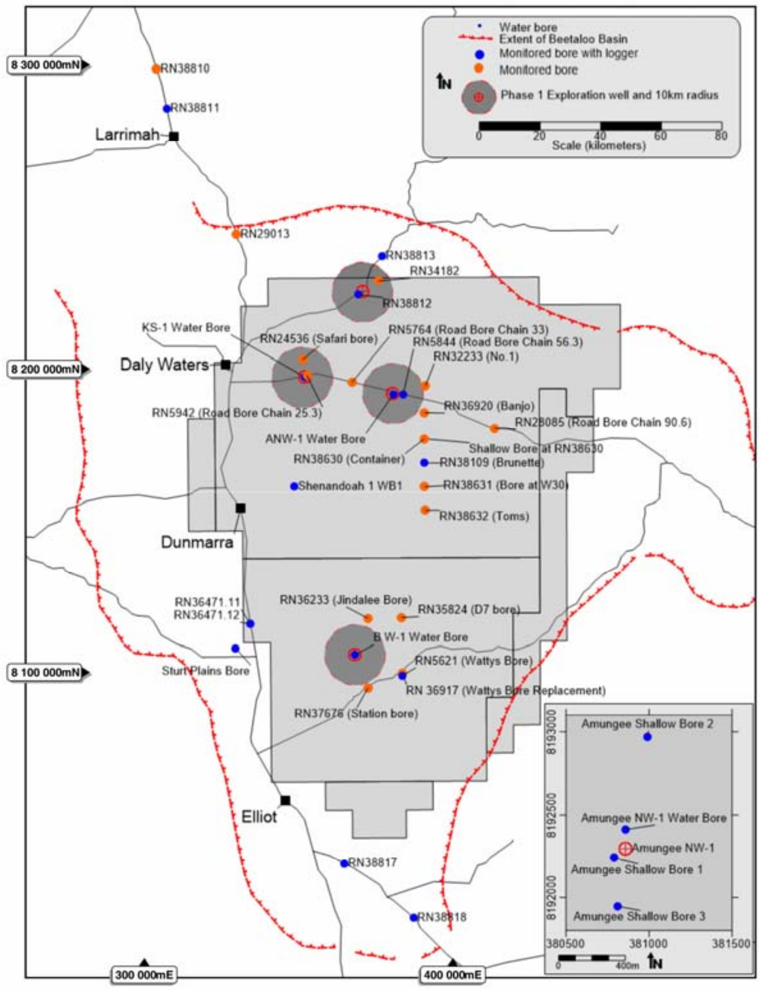


Figure 2.3: Origin's baseline groundwater monitoring network

Water monitoring includes twice yearly testing of all waterbore wells, where samples are taken from each well and analysed for a range of water quality indicators at an independent laboratory. These data are critical to demonstrating that exploration activities, including hydraulic fracture stimulation, have not impacted the aquifer(s). In addition to the discrete sampling program, approximately half of the wells being monitored are equipped with pressure logger devices, which provide a continuous recording of standing water level.

In addition, to further expand on the preliminary baseline water monitoring program, Origin approached Santos and CSIRO to discuss a regional assessment - akin to studies carried out in other Australian jurisdictions under the GISERA framework. Origin and Santos co-funded a scope of work proposed by CSIRO and that work is due to be completed and reported back on in mid-2018. Origin respectfully request that the Panel request an update from CSIRO on the status of that work to date.

We respectfully request that the Panel consider whether it can be more explicit in reporting that it is incorrect to suggest that no baseline data or baseline monitoring is taking place.

2.4 Amungee NW-1H Hydraulic Fracture Stimulation Operations
Additional Detail pertaining to Horizontal Casing Deformation Event

2.4.1 Background information

1. The Amungee NW-1H well was drilled in late 2015 (28/10/2015 to 14/11/2015) and then suspended.

2. Amungee NW-1H is a horizontal well with a lateral section of approximately 1000m in the target “B Shale” of the middle Velkerri Formation.

3. The horizontal section of the well was drilled with a 6 ¾” bit and designed to be completed with a 4 ½” production casing string.

4. The well was re-entered in June, 2016, and production casing was installed in July, 2016, from the surface to the total depth (TD) of the well at 3808 m measured depth and then cemented.

5. Casing was selected with physical properties, ratings and certifications that would ensure the pressures required to successfully execute the hydraulic fracture stimulation operations could be achieved.

6. Key production casing parameters:
   i. Size: 4.5”
   ii. Weight: 15.1 ppf
   iii. Grade: P-110
   iv. Thread: JFE BEAR (Premium Gas Tight Connection).

7. Pages 59 to 68 of Origin’s April 30 submission provides further details regarding casing, cementing and pressure testing of the well.

8. “Plug and perf” was selected as the stimulation deployment strategy for Amungee NW-1H – this method of hydraulic fracturing is the most commonly deployed technique for shale gas wells.

9. Plug and perf operations involve:

   i. dividing the lateral section of the well into stages. A stage is typically a 50-200 metre section of the horizontal well, starting at the toe or deepest part of the well (i.e. the first stage is at the toe of the well). Each stage will be perforated over 1-3 intervals and each is between 1-3 metres long.

   ii. pumping hydraulic stimulation fluid and proppant down the production casing through the perforations until the “stage” is complete (e.g. 1 ML and 100 tonnes of proppant).

   iii. placing a plug (usually using wireline) uphole (i.e. away from the toe and towards the heel of the well) of the perforations used in the prior stage to isolate the prior stage from new perforation clusters that will be used for the next stage.

   iv. repeating steps i-iii until all stages are completed.

10. Origin elected to use “flow-through” plugs in the event it was not possible to drill out (or “mill”) the plugs used to isolate each of the stages – the most common reason that it may not be possible to drill out plugs is due to casing deformation events in the horizontal section of the well that are associated with hydraulic fracturing.

11. 12 stages were planned for Amungee NW-1H, with the spacing and intervals selected based on modelled reservoir properties and the locations of interpreted small faults (average 6 metres of throw with a maximum ~15 metres of throw) – a 20 metre standoff from the faults was incorporated into the stage design.

12. The well encountered no substantial faults, as per Origin’s pre-drill interpretation. The execution of safely drilling and stimulating the Amungee well is evidence of Origin’s ability to identify safe technical zones within the target formation. The drilling plan accounted for small faults being encountered (as sub-seismic faults are always present) in the subsurface.

13. DFIT and stimulation operations were conducted from 25 August to 8 September 2016.

14. 11 stages were successfully pumped into the formation – each of the 11 stages was separately executed by injecting fluid directly down the production casing at rates up to 50 bpm (barrels per minute) while treating pressures remained below 9300 psi.

2.4.2 Casing Deformation

1. A casing obstruction or restriction was encountered after Stage 7 during the operation to place a plug to isolate Stage 7 from Stage 8.

2. The restriction, encountered at 3117 metres measured depth (coiled tubing depth estimate), prevented the plug to be set at the planned depth of 3183 metres.

Origin deems it important to highlight that technically the total depth of a well is the sum of the total length of the well. That is, from surface to the end of the horizontal length. In the Amungee well this includes the vertical length and the horizontal length until the well ultimately ends).

3. The plug initially became stuck at the restriction, but pressure from the toe section of the well dislodged the plug, which confirmed that the wellbore was not disconnected by the restriction and that there was communication with the well on the toe-side of the restriction.

4. Coiled tubing was used to make a summary investigation of the obstruction and confirm that there was a reduction in the diameter of the casing at the restriction.

5. A conservative offset from where the restriction was observed was incorporated into re-spacing the remaining stages towards the heel of the wellbore (Figure 1); but no other immediate action was required as we were confident that as we had deployed flow-through plugs a production test that included contribution from Stages 1-6 would still be achievable.

6. Coiled tubing was used at the completion of stimulation operations to mill out five bridge plugs up-hole of the wellbore obstruction – the remaining flow-through plugs were not milled out but left in place in the horizontal wellbore (it is our interpretation that the stages below the wellbore obstruction contributed to the wellbore production due to the flow-through design of the plugs).

7. Origin and its prime contractor Schlumberger are familiar with casing deformation events in the horizontal section and understand that they pose no risk to operational safety, well integrity or the environment (BCOGC, 2014 - attached) – the horizontal well section is designed to be perforated and create a pathway for gas to flow from the reservoir to the surface through the well bore and importantly the horizontal part of the well is not designed to provide barrier protections required for well integrity (short term or long term). The multiple barrier protection layers - of casing and cement - exist in the vertical section of the well to mitigate interfacing and connecting with the environment.

8. The casing deformation event is therefore not relevant from a well integrity perspective, it is, however, potentially relevant from an operations, execution and potentially economic perspective (although there are insufficient data to establish whether this will be the case).

9. Origin has discussed the casing deformation or wellbore obstruction event widely and openly in the context of the potential impacts on the Amungee NW-1H extended production test, however, it has not been discussed widely in other contexts as it is a minor, relatively common event of no significance in terms of well integrity or environmental protection.

> *Origin sees that the technical term of 'casing deformation' can contribute to confusion and concern in the community if one is not familiar with the same.*

2.4.3 Attempted Twelfth Stage

1. Stage 12 was attempted on 8 September 2016, however fracture initiation for that interval was not achieved and the stage was terminated without fracturing the reservoir or placing any proppant – a total of only ~60 barrels of fluid was injected into the stage over the course of several hours.

2. An inability to create a fracture does not create a safety, environmental or well integrity risk.

2.5 Origin 2014 Risk Assessment of Aquifer Crossflow and Drilling Program Changes to Eliminate Risk

Origin undertook a third-party risk assessment in 2014-15 prior to the 2015 Beetaloo drilling program.

One of the unmitigated risks identified during this assessment was of crossflow between two shallow, potable aquifers - specifically in regions of the southern Beetaloo Sub-basin where there is an aquifer that was identified within sandstones of the Undifferentiated Cretaceous cover over the Cambrian Limestone Aquifers (Figure 1). The unmitigated risk arises if the aquifers can communicate during or following the drilling of the surface hole of an exploration well or if the aquifers are isolated behind a single casing string. Such an event was considered a “Medium” environmental risk and, realistically, occurs any time a water bore is drilled to the Cambrian Limestone Aquifer in an area where such Cretaceous sandstones occur (noting that both aquifers have similar water chemistry and quality and is therefore likely to be of low concern for water bore drillers and/or landholders). The unmitigated risk consequence, however, was identified as of “Serious” consequence in the risk assessment conducted by Origin. Origin’s risk assessment methodology is broader than environmental risk alone and incorporates the Northern Territory Water Act regulations, which do not permit aquifer crossflow.

Although the unmitigated crossflow risk is specific to the shallow, potable aquifers in a specific area it has been incorrectly interpreted by media, and accepted as fact by some, to be relevant to all aquifers in all parts of the Beetaloo Sub-basin, this is not the case. The crossflow from deeper aquifers is prevented by the drilling and casing design of exploration wells; and this is the case for conventional and unconventional wells and is not related to hydraulic fracture stimulation in any way.

The risk assessment has been raised on several occasions by opposition groups who seek to highlight, out of context, a section from a technical document to claim that an ‘Origin report concludes fracking will cause contamination of ground water’. It’s been a good learning in terms of how a risk assessment can be interpreted by non-technical specialists.

To mitigate or eliminate the crossflow risk Origin re-engineered and designed the emplacement of the conductor and surface casing, and used casing while drilling technology, to prevent crossflow between the Cretaceous and Cambrian aquifers (known as risk controls). In the final Beetaloo W-1 well design the conductor hole was drilled with the conductor casing (i.e. installing the casing while drilling) to below the level of the Cretaceous Aquifer and then cemented in place (Figure 2.5a). The surface hole was then drilled to below the Cambrian Limestone Aquifer (Figure 2.5b). This re-design mitigated the risk that “…multiple shallow aquifers…are proposed in well design to be sealed by a single run of cemented surface casing” (Fulton and Knapton, 2015).

In summary, following the risk assessment, the drilling design for wells in the area where the unmitigated risk was identified was changed to use two surface casing strings - effectively eliminating the identified cross-flow risk. Further to this, we successfully executed the new design and no incidents of shallow aquifer cross-flow occurred. This example highlights the thoroughness with which our risk assessments are completed, and our ability to design out risks.

Distribution of Ground Water Bores and Source Aquifers

PROVINCE	PERIOD / AGE	FORMATION		AQUIFER STATUS	THICKNESS (m)	YIELD (l/s)	AVE. EC (µs/cm)
CARPENTARIA BASIN	CRETACEOUS 145 – 66 Ma	Undifferentiated		*Local Aquifer*	0 - 130	0.3 - 4	1800
GEORGINA BASIN	CAMBRIAN 497-630 Ma	Cambrian Limestone Aquifer (CLA)	Anthony Lagoon Beds	REGIONAL AQUIFER	0 – 200	1 - 10	1600
			Gum Ridge Formation	REGIONAL AQUIFER	0 – 300	0.3 - >20	1400
		Antrim Plateau Volcanics		REGIONAL AQUITARD *Local Aquifer*	0 – 440	0.3 - 5	900
		Bukalara Sandstone		*Local Aquifer*	0 – 75	0.3 - 5	1000
BEETALOO BASIN (ROPER GROUP)	NOT KNOWN	Hayfield Mudstone		REGIONAL AQUITARD *Local Aquifer*	0 – 450	-	32000
		Jamison Sandstone		*Local Aquifer*	0 – 150	-	138000
	MESO-PROTEROZOIC 1430-1500 Ma	Kyalla Formation		REGIONAL AQUITARD	0 – 800	-	-
		Moroak Sandstone		*Local Aquifer*	0 – 500	0.5 - 5	131000
		Velkerri Formation		REGIONAL AQUITARD	700 – 900	-	-
		Bessie Ck Sandstone		*Local Aquifer*	450	0.5 - 5	-

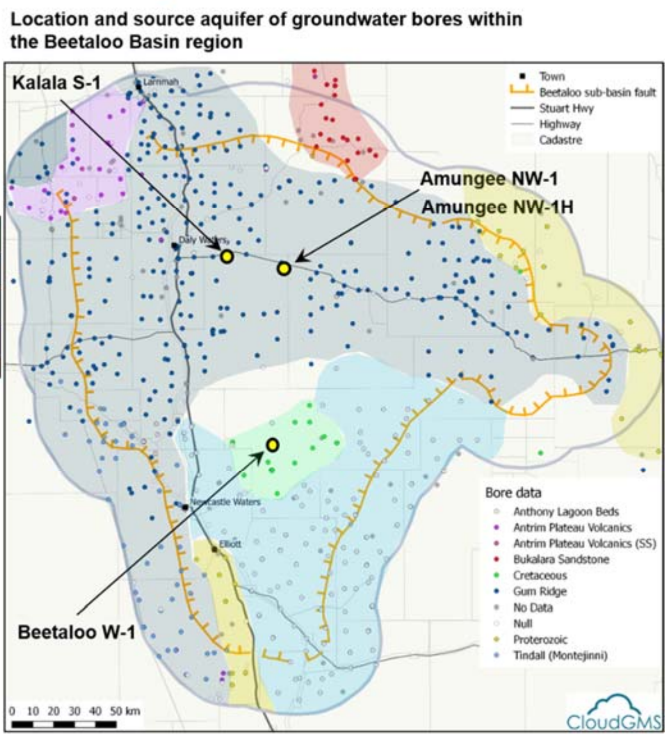


Figure 2.5a: Distribution of groundwater bores and the primary source aquifers showing that the area where the risk of communication between the Cretaceous and Cambrian Limestone aquifers is limited to a portion of the southern / central Beetaloo Sub-basin (green highlighted area).

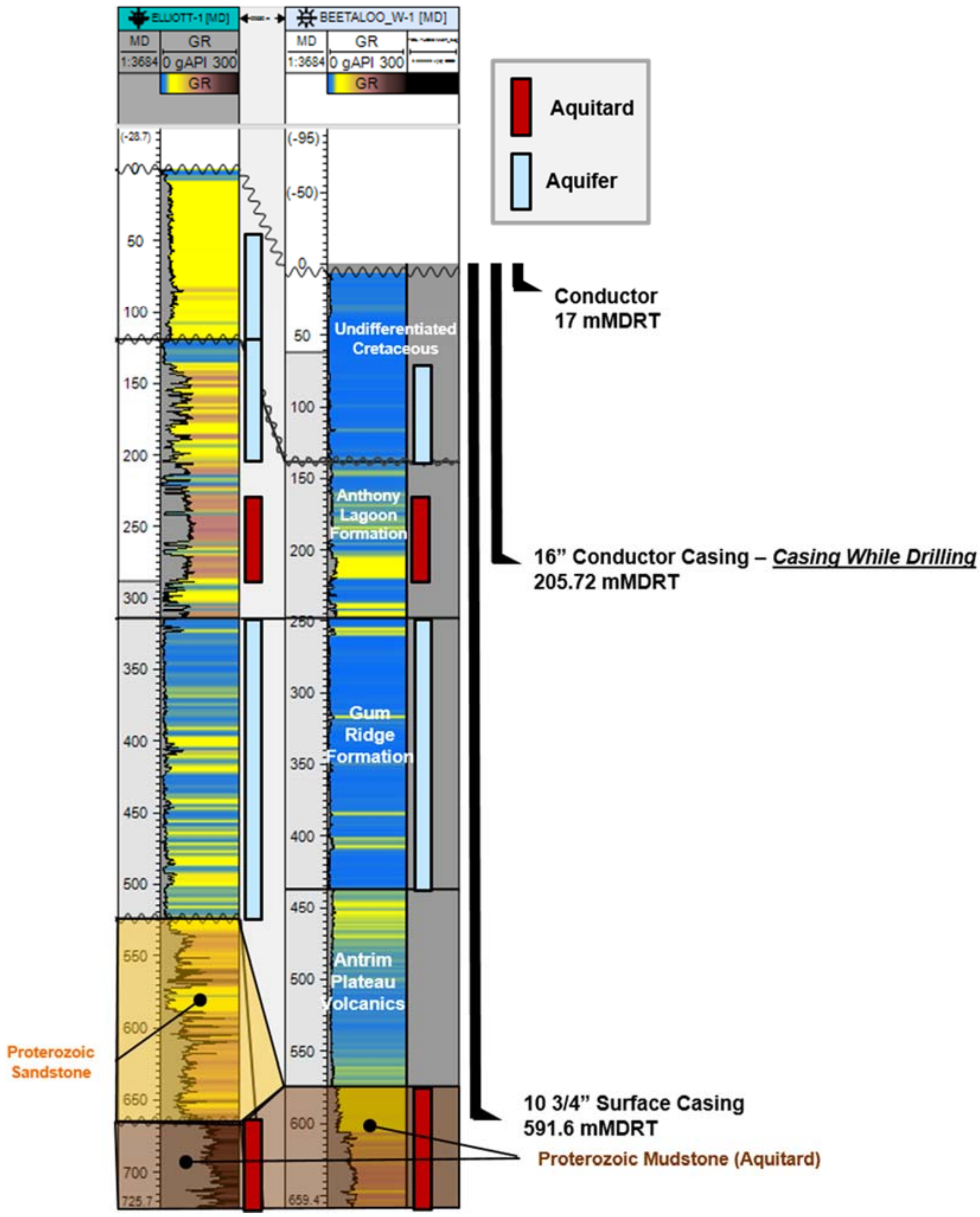


Figure 2.5b: Conductor and casing configuration at Beetaloo W-1 (right hand well panel) that shows the updated design separating the two shallow, potable aquifers behind separate casing strings

Statement A - Draft Final Report Recommendations

Accept and Support

Origin accept and support the following eighty-one (81) recommendations as they are represented in the NT Inquiry's Draft Final Report dated December 2017.

Chapter 5: Shale gas extraction and development

Recommendation 5.1

Recommendation 5.4 – 5.8

Chapter 7: Water

Recommendation 7.3

Recommendation 7.9

Recommendation 7.12 – 7.19

Chapter 8: Land

Recommendation 8.3 – 8.10

Recommendation 8.12 – 8.14

Recommendation 8.16

Chapter 9: Greenhouse Gas Emissions

Recommendation 9.1 to 9.4

Recommendation 9.6 to 9.7

Chapter 10: Public Health

Recommendation 10.2

Chapter 11: Aboriginal people and their culture

Recommendation 11.4

Recommendation 11.6 – 11.7

Chapter 12: Social impacts

Recommendation 12.1 to 12.11

Recommendation 12.14 to 12.15

Chapter 13: Economic impacts

Recommendation 13.1 to 13.10

Chapter 14: Regulatory reform

Recommendation 14.2 to 14.4

Recommendation 14.6 – 14.8

Recommendation 14.11 – 14.12

Recommendation 14.15

Recommendation 14.17 – 14.22

Recommendation 14.24

Recommendation 14.26 – 14.28

Recommendation 14.31

Statement B - Draft Final Report Recommendations

Agree and support the intent / principle of the following Recommendation(s)

Origin accept and support the intent / principle of the following recommendations and for each:

a. offer some additional information relating to process and / or applicability of the recommendation; or
b. seek additional clarification on the recommendation (as it presently stands); or
c. propose an amendment.

Chapter 5: Shale gas extraction and development

Recommendation 5.2

That the Government mandate a program for the ongoing monitoring of abandoned shale gas wells in the NT. The program must include the ongoing monitoring of water quality by bores installed adjacent to the well and the results of such monitoring to be *published in real-time*.

> *If a risk based monitoring program is to be developed, the following points should be considered:*
>
> - *the geological setting of the basin so as any site-specific risks can be planned for, managed and monitored;*
> - *the requirements and outcomes achieved through decommissioning performed in accordance with the code of practice for abandonment of wells (Recommendation 5.1); and*
> - *minimising clearing and land disturbance of other impact required to manage risk.*

Origin would be able to accept Recommendation 5.2 if the following proposed amendments were incorporated:

That the Government mandate a program for the ongoing monitoring of abandoned shale gas wells in the NT. The program must include the ongoing monitoring of water quality by bores installed adjacent to the well and the results of such monitoring be *reported to Government and made publicly available*.

Recommendation 5.3

That in consultation with industry and other stakeholders, the Government develop and mandate an enforceable code of practice setting out the minimum requirements that must be met to ensure the integrity of the onshore shale gas wells in the NT. This code must require that:

- all onshore shale gas wells (including exploration wells constructed for the purposes of production testing) be constructed to at least a Category 9 (or equivalent) standard, with cementing extending up to at least the shallowest problematic hydrocarbon bearing, organic carbon rich or saline aquifer zone;
- all wells be fully tested for integrity before and after hydraulic fracturing and the results be independently certified, with the immediate remediation of identified issues required;
- an ongoing program of integrity testing be established for each well during its operational life. For example, every two years initially for a period of 10 years and then at five-yearly intervals thereafter to ensure that if any issues develop they are detected early and remediated; and
- the results of all well integrity testing programs and any remedial actions undertaken be publicly reported.

With respect to the Beetaloo shale basin, Origin recognise Category 9 wells as having an intermediate casing though note that it is plausible that not all wells will require intermediate casing (such as wells potentially targeting the Kyalla formation). Origin comprehensively agrees with, and supports, a requirement to cement below potable aquifers and above the shallowest hydrocarbon bearing zone or saline aquifer.

Origin agrees with the intent of ensuring the integrity of a well before hydraulic fracture stimulation (HFS) though we seek clarification on the intent of integrity testing post HFS. Reason being is that once the HFS is executed, annular pressures are being constantly monitored as a test for well integrity and it is not technically possible to execute pressure testing in a live well when the well is operational and open to the formation. Rather the wellhead is routinely inspected and tested.

Origin would be able to accept Recommendation 5.3 if the following proposed amendments were incorporated:

That in consultation with industry and other stakeholders, the Government develop and mandate an enforceable code of practice setting out the minimum requirements that must be met to ensure the integrity of onshore shale gas wells in the NT. This code must require that:

- *Surface casing will be set below the potable aquifer and that the cement will be set above the hydrocarbon zone*;
- *all onshore shale gas wells (including exploration wells constructed for the purposes of production testing) be constructed so that cementing extends up to at least the shallowest hydrocarbon-bearing or saline aquifer zone;*
- **all wells be tested and monitored for integrity before and after hydraulic fracturing and the results be independently certified, with the immediate remediation of identified issues required;**
- **an ongoing program of integrity testing be established for each well during its operational life. For example, every two years initially for a period of 10 years and then at five-yearly intervals thereafter to ensure that if any issues develop they are detected early and remediated; and**
- **the results of all well integrity testing programs and any remedial actions undertaken be publicly reported**

Chapter 7: Water

Recommendation 7.1

That before any *production licence* is granted to extract onshore shale gas, the Water Act be amended to require gas companies to obtain water extraction licences under that Act. That the Government introduce a charge on water in the NT for all onshore shale gas activities.

Origin presented to the Inquiry its representation that a Production License is a tenure instrument rather than a consent and / or approval for activity and respectfully request that the use of Production License in some recommendations be substituted with wording akin to "approval of development and production activities".

Origin would be able to accept Recommendation 7.1 if the following proposed amendments were incorporated:

That before *an approval for onshore shale gas development and production activities* is granted, the Water Act be amended to *require gas companies to obtain water extraction licences under that Act*. That the Government consider introducing a charge on water in the NT for all onshore shale gas activities.

Recommendation 7.2

That the Government request the Australian Government to amend the EPBC Act to apply the 'water trigger' to all onshore shale gas development.

If the NT Inquiry's Water and HHRA related recommendations are adopted in full then applying the EPBC Act's 'water trigger' should not be required.

Origin would be able to accept Recommendation 7.2 if the following proposed amendments were incorporated:

That the Government request the Australian Government to *consider the applicability of* the EPBC Act's 'water trigger' to all onshore shale gas development.

Recommendation 7.4

That a strategic regional environmental and baseline assessment (SREBA), including a regional groundwater model, be developed and undertaken for any prospective shale gas basin before *any production licences* are granted for shale gas activities in that basin, commencing with the Beetaloo Sub-basin.

Origin presented to the Inquiry its representation that a Production License is a tenure instrument rather than a consent and / or approval for activity and respectfully request that the use of Production License in some recommendations be substituted with wording akin to "approval of development and production activities".

Origin would be able to accept Recommendation 7.4 if the following proposed amendments were incorporated:

That a strategic regional environmental and baseline assessment (SREBA), including a regional groundwater model, be developed and undertaken for any prospective shale gas basin before *approvals for onshore shale gas development and production activities* are granted for shale gas activities in that basin, commencing with the Beetaloo Sub-basin.

Recommendation 7.5

That the use of all surface water resources for all onshore unconventional shale gas hydraulic fracturing in the NT be prohibited.

Origin would be able to accept Recommendation 7.5 if the following proposed amendments were incorporated:

That the use of all surface water resources for all onshore unconventional shale gas hydraulic fracturing in the NT be prohibited *until a comprehensive hydrological impact risk assessment is completed*.

Recommendation 7.6

That in relation to the Beetaloo Sub-basin:

- the Daly-Roper WCD be extended south to include all the Beetaloo Sub-basin;
- a separate WAP be developed for the northern and southern regions of the Beetaloo Sub-basin;
- the new northern Basin WAP provide for a water allocation rule that restricts the consumptive use to less than that which can be sustainably extracted without having adverse impacts on other users and the environment; and
- the southern Basin WAP prohibits water extraction for shale gas production until the nature and extent of the groundwater resource and recharge rates in that area is quantified.

That in relation to other shale gas basins with similar or greater rainfall than the Beetaloo Sub-basin, WCDs be declared and WAPs be developed to specify sustainable groundwater extraction rates for shale gas production that will not have adverse impacts on existing users and the environment.

That in relation to other potential shale gas basins in semi-arid and arid regions, all groundwater extraction for any shale gas production be prohibited until there is sufficient information to demonstrate that it will have no adverse impacts on existing users and the environment

Origin would be able to accept Recommendation 7.6 if the following proposed amendments were incorporated:

That in relation to the Beetaloo Sub-basin:

- the Daly-Roper WCD be extended south to include all the Beetaloo Sub-basin;
- a separate WAP be developed for the northern and southern regions of the Beetaloo Sub-basin;
- the new northern Basin WAP provide for a water allocation rule that restricts the consumptive use to less than that which can be extracted without having adverse impacts on other users and the environment **in** *consideration of the nature and extent of the consumptive use*; and
- the southern Basin WAP prohibits water extraction for shale gas production until the nature and extent of the groundwater resource and recharge rates in that area is quantified.

That in relation to other shale gas basins with similar or greater rainfall than the Beetaloo Sub-basin, WCDs be declared and WAPs be developed to *in consideration of the nature and extent of consumptive use of shale gas production* that will not have adverse impacts on existing users and the environment.

That in relation to other potential shale gas basins in semi-arid and arid regions, all groundwater extraction for any shale gas production be prohibited until there is sufficient information to demonstrate that it will have no adverse impacts on existing users and the environment

Recommendation 7.7

That the following measures be mandated to ensure that any onshore shale gas development does not cause unacceptable local drawdown of aquifers:

- the drilling of onshore shale gas petroleum wells within 1 km of existing or proposed groundwater bores be prohibited unless hydrogeological investigations and groundwater modelling indicate that a different distance is appropriate, or if the landholder is in agreement with a closer distance;
- additional information on the aquifer characteristics is obtained as a result of the regional environmental and baseline assessment recommended in Section 7.4.1;
- relevant WAPs include provisions that adequately control both the rate and volume of water extraction by the gas companies;
- gas companies be required, at their expense, to monitor drawdown in local water supply bores; and
- companies be required to 'make good' any problems if this drawdown is found to be excessive *(that is greater than 1 m)*.

Origin would be able to accept Recommendation 7.7 if the following proposed amendments were incorporated:

That the following measures be mandated to ensure that *the gas production phase for an* onshore gas development does not cause unacceptable local drawdown of aquifers:

- the drilling of onshore shale gas petroleum wells within 1 km of existing or proposed groundwater bores be prohibited unless hydrogeological investigations and groundwater modelling indicate that a different distance is appropriate, or if the landholder agrees with a closer distance;
- *additional information on the aquifer characteristics is obtained as a result of the regional environmental and baseline assessment recommended in Section 7.4.1*;
- *relevant WAPs include provisions that adequately control both the rate and volume of water extraction by the gas companies to manage risk*;
- *gas companies be required to monitor drawdown in local water supply bores*; and
- companies be required to 'make good' any problems if this drawdown is found to be excessive *as determined by the SREBA findings and WAP*.

Recommendation 7.8

That reinjection of wastewater into deep aquifers and conventional reservoirs should be prohibited until comprehensive geotechnical investigations are *undertaken to show that no seismic activity will occur.*

Origin would be able to accept Recommendation 7.5 if the following proposed amendments were incorporated:

That reinjection of wastewater into deep aquifers and conventional reservoirs should be prohibited until comprehensive geotechnical investigations are _undertaken to determine whether any identified risks can be adequately mitigated and managed_.

Recommendation 7.10

That in order to minimise the risk of groundwater contamination from leaky gas wells :

- _all wells to be hydraulically fractured must be constructed to at least category 9 or equivalent and tested to ensure well integrity before and after hydraulic fracturing, with the results certified by the Regulation (see also Recommendations 5.3 and 5.4)_;
- a minimum offset distances of at least 1km between pads must be adopted unless specific site-specific information is available to the contrary (see also Recommendation 7.7);
- a robust and rapid wastewater spill clean up management plan must be prepared for each well pad to ensure immediate remediation in the event of a spill; and
- _real time publicly available groundwater quality monitoring must be implemente4d around each well pad to detect any groundwater contamination. Multi-level observation bores must be used to ensure full coverage of the aquifer horizon with a level of vertical resolution sufficient to be able to identify the location of any leak._

Origin would be able to accept Recommendation 7.10 if the following proposed amendments were incorporated:

That to minimise the risk of groundwater contamination from leaky gas wells:

- _well integrity is to be independently verified_ (Recommendations 5.3 and 5.4)
- a minimum offset distance of at least 1 km between _existing and active groundwater supply bores and well pads_ must be adopted unless specific site-specific information is available to the contrary (see also Recommendation 7.7);
- a robust and rapid wastewater spill clean-up management plan must be prepared for each well pad to ensure immediate remediation in the event of a spill: and
- _a groundwater quality monitoring program is to be developed and implemented based on the outcomes of the HHRA (completed as per recommendation 7.3)_.
- _if the groundwater monitoring program determines a potential leak from a gas well to be occurring, then a targeted investigation is to be undertaken to identify the location of the leak and inform any remedial actions required in accordance with the Integrity Management System (recommendation 5.4)_.

Recommendation 7.11

That to reduce the risk of contamination of surface aquifers from on-site spills of wastewater:

- the EMP for each well pad must include an enforceable wastewater management plan and spill management plan, which must be approved prior to the commencement of hydraulic fracturing;
- enclosed tanks must be used to hold all wastewater;
- the well pad site must be treated (for example, with a geomembrane) to prevent the infiltration of wastewater spills into underlying soil and thence into to an aquifer; and
- a real-time publicly accessible monitoring program for each well pad must be established.

Origin would be able to accept Recommendation 7.11 if the following proposed amendments were incorporated.

That to reduce the risk of contamination of surface aquifers from on-site spills of wastewater:

- the EMP for each well pad must include an enforceable wastewater management plan and spill management plan, which must be approved prior to the commencement of hydraulic fracturing;
- *wastewater storage must be designed and managed based on the outcomes of the HHRA and in consideration of climatic conditions and variability to manage the risk of overtopping*;
- *well pads must be designed and managed based on the outcomes of the HHRA, including managing risk of adverse impact to groundwater from surface spills; and*
- *based on the outcome of the HHRA, a monitoring program must be established and implemented. The results of monitoring are to be made publicly available*.

Chapter 8: Land

Recommendation 8.1

That strategic regional terrestrial biodiversity assessments are conducted as part of a SREBA for all bioregions prior to *any* onshore shale gas production, with all onshore shale gas development excluded from areas considered to be of high conservation value. The results of the SREBA must inform any decision to release land for exploration as specified in Recommendation 14.2 and be considered by the decision-maker in respect of any activity-based EMP.

Origin would be able to accept Recommendation 8.1 if the following proposed amendments were incorporated

That strategic regional terrestrial biodiversity assessments are conducted as part of a SREBA for all bioregions prior to *approvals for* onshore shale gas *development and* production *activities*, with all onshore shale gas development excluded from areas considered to be of high conservation value. The results of the SREBA must inform any decision to release land for exploration as specified in Recommendation 14.2 and be considered by the decision-maker in respect of any activity-based EMP.

Recommendation 8.2

That a baseline assessment of all weeds within a permit area be conducted prior to any onshore shale gas exploration or development and that ongoing weed monitoring be undertaken to inform any weed management measures necessary to ensure no incursions or spread of weeds. Gas companies must have *a dedicated weed officer whose role is* to monitor well pads, roads and pipeline corridors for weeds.

Origin would be able to accept Recommendation 8.2 if the following proposed amendments were incorporated

That a baseline assessment of all weeds within an activity area be conducted prior to any onshore shale gas development and that a weed management plan and ongoing weed monitoring be undertaken to inform any weed management measures necessary to ensure no incursions or spread of weeds. Gas companies must have *appropriately trained personnel for weeds management to* monitor well pads, roads and pipeline corridors for weeds.

Recommendation 8.11

That corridor widths be kept to a minimum, with pipelines and other linear infrastructure buried, except for necessary inspection points, and the disturbed ground revegetated.

Origin would be able to accept Recommendation 8.11 if the following proposed amendments were incorporated

That corridor widths be kept to a minimum, with pipelines and other linear infrastructure buried, except for necessary inspection points *and within operational areas and temporary activities*, and the disturbed ground revegetated.

Recommendation 8.15

That to minimise the impact of any onshore shale gas industry on landscape amenity, gas companies must *demonstrate that they have minimised the surface footprint of development to ALARP, including that:*

- *well pads are spaced a minimum of 2 km apart; and*
- *the infrastructure within any development areas is not visible from major public roads*.

Origin would be able to accept Recommendation 8.15 if the following proposed amendments were incorporated

That to minimise the impact of any onshore shale gas industry on landscape amenity, gas companies *not exceed One (1) well pad per 3km^2 or cumulative surface impact no greater than five percent (5%) of a graticular block. Exceptions to this must be agreed to by all parties, prior to being considered and / or accepted by the Regulator*.

Chapter 9: Greenhouse Gas Emissions

Recommendation 9.5

That all monitoring results should be published online on a *continuous basis in real time*.

Origin would be able to accept Recommendation 9.5 if the following proposed amendments were incorporated

That all monitoring results should be published online on a *regular basis in accordance with the NGERS*.

Chapter 10: Public Health

Recommendation 10.1

That formal site or regional-specific HHRA reports be prepared and approved prior to the *grant of any production licence* for the purpose of any shale gas development. Such HHRA reports to address the potential human exposures and health risks associated with the exploration for, and the production of, any shale gas development, off-site transport, and the decommissioning of wells, as recommended in NCRA guidance. The HHRA reports must include risk estimates assessments of exposure pathways that are deemed to be incomplete.

> *Origin presented to the Inquiry its representation that a Production License is a tenure instrument rather than a consent and / or approval for activity and respectfully request that the use of Production License in some recommendations be substituted with wording akin to "approval of development and production activities".*

Origin would be able to accept Recommendation 10.1 if the following proposed amendments were incorporated

That formal site or regional-specific HHRA reports be prepared and approved prior to the *approval of any production activities* for the purpose of any shale gas development. Such HHRA reports to address the potential human exposures and health risks associated with the exploration for, and the production of, any shale gas development, off-site transport, and the decommissioning of wells, as recommended in NCRA guidance. The HHRA reports must include risk estimates assessments of exposure pathways that are deemed to be incomplete.

Recommendation 10.3

That in consultation with industry, landowners and local communities, the regulator set appropriate setback distances to minimise risks identified in HHRA reports, including potential pathways for waterborne and airborne contaminants, for all shale gas development (exploration and production). *Such setback distances to be not less than 1,600 m*.

> *Origin supports objective-based recommendations that allow fit-for-purpose set back distances based on targeted and localised risk assessments.*

Origin would be able to accept Recommendation 10.3 if the following proposed amendments were incorporated

That in consultation with industry, landowners and local communities, the regulator set appropriate setback distances to minimise risks identified in HHRA reports, including potential pathways for waterborne and airborne contaminants, for all shale gas development (exploration and production). *The outcomes of the HHRA in consideration of mitigation and management controls must be used to inform the setback distance(s)*.

Chapter 11: Aboriginal People and their Culture

Recommendation 11.1

That gas companies be required to obtain an Authority Certificate before undertaking any onshore shale gas *activity*.

Origin would be able to accept Recommendation 11.1 if the following proposed amendments were incorporated

That gas companies be required to obtain an Authority Certificate ***where a sacred site has been identified within proximity of a proposed activity***.

Recommendation 11.2

That AAPA:
- be provided with a copy of any application to conduct hydraulic fracturing for onshore shale gas under petroleum environment legislation at an early stage of the assessment and approval process;
- be given an adequate opportunity to explain the application to custodians; and
- be given an adequate opportunity to comment on the application and have those comments considered by the decision-maker.

Origin would be able to accept Recommendation 11.2 if the following proposed amendments were incorporated

That AAPA:
- be provided with a copy of any application to conduct hydraulic fracturing for onshore shale gas under petroleum environment legislation at an early stage of the assessment and approval process **as long as it doesn't duplicate any of the current processes in place**;
- be given an adequate opportunity to validate that the activities of the application have been explained to custodians; and
- be given an adequate opportunity to comment on the application and have those comments considered by the decision-maker.

Recommendation 11.3

That legislation for the protection of sacred sites be amended so that sub-surface formations can be included as a sacred site or a feature of a sacred site.

Origin accept a Sacred Site as identified by host Traditional Owners during the cultural heritage survey work process and accept that such sights can be at both surface and sub-surface. Current legislation does not prescribe surface and / or subsurface so it is taken that it can be either. Current Exploration Agreement obligations, including conducting cultural heritage survey(s) prior to activities ensure Origin's host Traditional Owners participate in early identification and protection of sites.

Origin would be able to accept Recommendation 11.3 if the following proposed amendments were incorporated

That legislation for the protection of sacred sites be amended so that sub-surface formations can be included as a sacred site or a feature of a sacred site *with a clearly defined framework in place that defines what formations or features meet criteria*.

Recommendation 11.5

That interpreters be used *at all* consultations with Aboriginal people for whom English is a second language. Interpreters must be appropriately supported to ensure that they understand the subject matter of the consultation.

Origin would be able to accept Recommendation 11.5 if the following proposed amendments were incorporated

Where requested by the relevant Land Council and host Traditional Owners, that interpreters be used *in* consultations with Aboriginal people for whom English is a second language. Interpreters must be appropriately supported to ensure that they understand the subject matter of the consultation.

Recommendation 11.8

That a comprehensive assessment of the cultural impacts of any onshore shale gas development be completed prior to the *grant of any production licence*. The cultural assessment must:

- be designed in consultation with Land Councils and AAPA;
- engage traditional Aboriginal owners, native title holders and the affected Aboriginal communities, and be conducted in accordance with world leading practice; and
- be resourced by the gas industry.

Origin presented to the Inquiry its representation that a Production License is a tenure instrument rather than a consent and / or approval for activity and respectfully request that the use of Production License in some recommendations be substituted with wording akin to "approval of development and production activities".

Origin would be able to accept Recommendation 11.8 if the following proposed amendments were incorporated

That a comprehensive assessment of the cultural impacts of any onshore shale gas development be completed prior to the *approval of any development* and production activities. The cultural assessment must:

- be designed in consultation with Land Councils and AAPA;
- engage traditional Aboriginal owners, native title holders and the affected Aboriginal communities, and be conducted in accordance with world leading practice; and
- be resourced by the gas industry.

Chapter 12: Social Impacts

Recommendation 12.12

That gas companies be required to develop a social impact management plan *that outlines how they intend to develop and continue their SLO within each of the communities they will operate in*. This should be developed in conjunction with any SIA, and introduced as early as possible, *preferably in the exploration phase*, to ensure that any potential changes can be flagged in advance to allow communities time to adapt and prepare for the changes.

Origin agrees that early engagement will serve the community, government and operators well however we caution against attempting to develop purposeful and targeted social impact management plans in the absence of a confirmed project to be developed.

Origin would be able to accept Recommendation 12.12 if the following proposed amendments were incorporated

That gas companies be required to develop a social impact management plan. This should be developed in conjunction with any SIA, and introduced as early as possible, to ensure that any potential changes can be flagged in advance to allow communities time to adapt and prepare for the changes.

Recommendation 12.13

That a strategic SIA, separate from an Environmental Impact Statement, be conducted in advance of any onshore shale gas development, *during the exploration phase*. Such SIAs must be conducted holistically to anticipate any expected impacts on infrastructure and services, and to mitigate potential negative impacts, and be funded by industry.

> *Origin maintains that further exploration is required to inform the optimum location and size of a potential future development. A purposeful SIA must then be anchored in, and contemplate, a plausible base of development which is not necessarily identifiable during the exploration phase. Origin commits to funding and executing SIAs, separate from EIS though preserve the right for it to be directly link a project area of influence so the impacts may be accurately assessed.*
>
> Origin would be able to accept Recommendation 12.13 if the following proposed amendments were incorporated
>
> That a strategic SIA, separate from an Environmental Impact Statement, be conducted in advance of any onshore shale gas development. Such SIAs must be conducted holistically to anticipate any expected impacts on infrastructure and services, and to mitigate potential negative impacts, and be funded by industry.

Recommendation 12.16

That in order to operationalise an SIA framework in the NT the Government should make the following structural reforms:

- introduce mechanisms for strategic assessment, either through a Strategic Assessment Agreement under the EBPC Act, or through reforms proposed in the 2015 Hawke Report. A strategic SIA is needed to decide if any onshore shale gas industry *should* go ahead, *and if so, under what conditions*;
- establish or enhance an independent authoritative body, such as the EPA or a newly established independent regulator (see Chapter 14), with powers to request information from, and to facilitate the collaboration between individual gas companies, and between gas companies, government agencies (including local government), communities and landholders;
- establish a long-term participatory regional monitoring framework, overseen by the EPA or the independent regulator, with secure funding (raised from industry *levies*) and able to endure multiple election cycles and
- establish periodic and standardised reporting to communities on the social, economic and environmental performance of the industry through either the independent regulator or a specialised research institution. This includes information from the monitoring of key indicators, and an industry-wide complaints and escalation process.

Origin would be able to accept Recommendation 12.16 if the following proposed amendments were incorporated

That in order to operationalise an SIA framework in the NT the Government should make the following structural reforms:

- *introduce mechanisms for strategic assessment, either through a Strategic Assessment Agreement under the EBPC Act, or through reforms proposed in the 2015 Hawke Report. A strategic SIA will identify the conditions for which any onshore shale gas industry* ***may*** *go ahead*;
- establish or enhance an independent authoritative body, such as the EPA or a newly established independent regulator (see Chapter 14), with powers to request information from, and to facilitate the collaboration between individual gas companies, and between gas companies, government agencies (including local government), communities and landholders;
- establish a long-term participatory regional monitoring framework, overseen by the EPA or the independent regulator, with secure funding (raised from industry *royalties*) and able to endure multiple election cycles and
- establish periodic and standardised reporting to communities on the social, economic and environmental performance of the industry through either the independent regulator or a specialised research institution. This includes information from the monitoring of key indicators, and an industry-wide complaints and escalation process.

Chapter 14: Regulatory Reform

Recommendation 14.1

That the Government design and *implement* a full cost recovery system for the regulation of any onshore shale gas industry.

Origin would be able to accept Recommendation 14.1 if the following proposed amendments were incorporated

That the Government *consider* the design and *implementation of* a full cost recovery system for the regulation of any onshore shale gas industry *as part of the regulatory and tax reform review*.

Recommendation 14.5

That prior to undertaking any onshore shale gas activity on a Pastoral Lease (including exploration), a land access agreement must be signed by the Pastoral Lessee and the gas company.

That the land access agreement be required by legislation.

That breach of the land access agreement will be a breach of the relevant approval giving rise to the petroleum activity being carried out on the land.

Origin agrees and Origin supports that transparency of compliance to the Regulator is reasonable, and along with other recommendations provides further support to ensure landholder rights are maintained. However, penalties for non-compliance with land access agreements is provided for within those agreements and should not be linked to other statutory approvals to undertake activity.

Origin would be able to accept Recommendation 14.5 if the following proposed amendments were incorporated

That prior to undertaking any onshore shale gas activity on a Pastoral Lease (including exploration), a land access agreement must be signed by the Pastoral Lessee and the gas company.

That the land access agreement be required by legislation.

That compliance to land access agreements be demonstrated in an annual statement to the Regulator.

Recommendation 14.9

That any person may lodge an objection to the proposed grant of an exploration permit.

That the Minister must, in determining whether to grant or refuse the application, take into account the objections received, and that all objections received by the Minister be published.

Origin would be able to accept Recommendation 14.9 if the following proposed amendments were incorporated

That any person *who has standing* may lodge an objection to the proposed grant of an exploration permit.

That the Minister must, in determining whether to grant or refuse the application, take into account the objections received, and that all objections received by the Minister be published.

Recommendation 14.10

That the Petroleum Act be amended to require the Minister to take into account and apply the principles of ESD.

Origin makes the observation that the NT Petroleum (Environment) Regulations 2016 currently requires the Minister to take into account and apply the principles of ESD.

Origin would be able to accept Recommendation 14.10 if the following proposed amendments were incorporated

That government consider amending the Petroleum Act to require the Minister to take into account and apply the principles of ESD.

Recommendation 14.13

That the government *impose* a non-refundable levy for the long-term monitoring, management and remediation of abandoned onshore shale gas wells in the NT.

Origin would be able to accept Recommendation 14.13 if the following proposed amendments were incorporated

As part of the development of a financial assurance framework, the government *incorporate* a non-refundable levy for the long-term monitoring, management and remediation of abandoned onshore shale gas wells in the NT.

Recommendation 14.14

That all draft EMPs for hydraulic fracturing must be published and available for public comment prior to Ministerial approval

That all comments made on draft EMPs be published.

That the Minister must take into account comments received during the public consultation period when assessing a draft EMP.

Origin would be able to accept Recommendation 14.14 if the following proposed principle were able to be incorporated into the recommendation

Origin considers it fair and reasonable that there should be clear statutory timelines for all applications, submissions and decision making processes.

Recommendation 14.16

That the Schedule be repealed and replaced with legislation to regulate seismic surveys, drilling, hydraulic fracturing, and well abandonment prior to the grant of any production licence for the purpose of any onshore shale gas development.

Origin presented to the Inquiry its representation that a Production License is a tenure instrument rather than a consent and / or approval for activity and respectfully request that the use of Production License in some recommendations be substituted with wording akin to "approval of development and production activities".

Origin would be able to accept Recommendation 14.16 if the proposed wording below were able to be considered:

That the Schedule be replaced with legislation to regulate seismic surveys, drilling, hydraulic fracturing, and well abandonment prior to the approval of any development and production activity.

Recommendation 14.23

Where litigation is brought genuinely in the public interest, that costs rules be amended to allow NT courts to not make an order for the payment of costs against an unsuccessful public interest litigant.

Origin would be able to accept Recommendation 14.23 if the following proposed principle were able to be incorporated into the recommendation

Courts have discretion not to award costs against unsuccessful litigants. In environmental matters the High Court has established principles when to award costs. We caution not to intervene with these established principles.

Conferring immunity from costs on public interest litigants is inappropriate as there needs to be protections against frivolous, vexatious, delaying, unreasonable and / or unnecessary proceedings.

Recommendation 14.25

That the Government enact whistle-blower protections.

That a hotline be established to make anonymous reports about any onshore shale gas industry non-compliance and that such reports be investigated.

Origin makes the observation that protective mechanisms for whistle-blowers should be applicable across whole of government, for all industries, and be consistent with other Australian jurisdictions.

Origin would be able to accept Recommendation 14.25 if the following proposed amendments were incorporated

That the Government enact whistle-blower protections _as part of a broader regulatory reforms_.

Recommendation 14.29

That the Government consider enacting provisions that reverse the onus of proof or create rebuttable presumptions for pollution and environmental harm offences for all regulated onshore shale gas activities.

Origin is presently unable to accept and support Recommendation 14.29. We refer the Panel to APPEA's submission with regard to this recommendation.

Recommendation 14.30

That penalties for environmental harm under the Petroleum Act and Petroleum Environment Regulations be reviewed and _increased in line with_ leading practice.

Origin would be able to accept Recommendation 14.30 if the following proposed amendments were incorporated

That penalties for environmental harm under the Petroleum Act and Petroleum Environment Regulations be reviewed and _aligned with_ leading practice.

Recommendation 14.32

That the Government develop and implement the reforms described in Option 1 and/or Option 2 above prior to _any production licences being issued for any_ onshore shale gas activities in the NT.

Origin presented to the Inquiry its representation that a Production License is a tenure instrument rather than a consent and / or approval for activity and respectfully request that the use of Production License in some recommendations be substituted with wording akin to "approval of development and production activities".

Origin would be able to accept Recommendation 14.32 if the following proposed amendments were incorporated

That the Government develop and implement the reforms described in Option 1 and/or Option 2 above prior to _approvals for_ onshore shale gas development _and production_ in the NT.

Recommendation 15.1

That a strategic regional environmental and baseline assessment (SREBA) be undertaken prior to the grant of any *production licence* for onshore shale gas.

Origin presented to the Inquiry its representation that a Production License is a tenure instrument rather than a consent and / or approval for activity and respectfully request that the use of Production License in some recommendations be substituted with wording akin to "approval of development and production activities".

Origin would be able to accept Recommendation 15.1 if the following proposed amendments were incorporated

That a strategic regional environmental and baseline assessment (SREBA) be undertaken prior to the grant of *approvals for development of* onshore shale gas

Statement C – Social Impact Recommendations

As requested by the Panel, Origin provides the following comments on the recommendations pertaining to the independent Social Impact work commissioned by the Inquiry.

Report 1 - Coffey Report Recommendations

●	*Recommendation 1*	The SIA Framework proposed by CSRM (2017) is implemented with appropriate lead time allowed for compiling a comprehensive social baseline. The framework to be implemented is to have regard to the following recommendations.

Origin supports this recommendation of a socio-economic baseline to be conducted in advance of major work which will form the basis of a comprehensive, common-user baseline from which all planning and planners can benefit. It also provides a platform from which to monitor, manage and measure the effectiveness of initiatives intended to improve socio-economic outcomes in localised areas of development. Origin strongly supports an overarching governance body and multi-user representation, which will be a critical determinant in the success of this recommendation.

●	*Recommendation 2*	Shale gas development proponents and the Northern Territory Government enter into a memorandum of agreement to share socio-economic data to enable compilation of a comprehensive sub-basin social baseline that is periodically updated.

Origin agrees in-principle with this recommendation and welcome the opportunity to work with the Northern Territory Government on securing and publishing a Memorandum of Agreement.

●	*Recommendation 3*	Shale gas development proponents enter into a memorandum of agreement for cost recovery of expenditure on baseline study, whereby late entrants who benefit from the comprehensive social baseline proportionally fund the work of the first movers.

Origin agrees in-principle with this recommendation and welcome the opportunity to maximise the delivery of collective benefit from the Northern Territory's natural gas resources but requests consideration be given as to the Commonwealth underwriting a percentage of the cost to incentives proponents to commit to a single point of truth for baseline / monitoring approach.

- *Recommendation 4*

A representative consultative committee comprising the Northern Territory Government, shale gas development proponents and community representative bodies is convened to deal with sub-basin wide issues and to integrate government and industry initiatives with community aspirations where appropriate.

Origin agrees in-principle with this recommendation and welcomes the establishment of a Beetaloo consultative committee as a priority in order to work in a constructive manner with the Northern Territory Government and community representative bodies.

- *Recommendation 5*

Shale gas development proponents implement awareness and education programs for affected communities that provide basic information on unconventional gas development, its impacts and their management ahead of discussion about impacts associated with a particular project. The programs involve suitably qualified technical experts to answer community questions and involve visits to operating unconventional gas fields to assist community representatives understand the activities and nature of impacts.

Origin agrees in-principle with this recommendation and looks forward to participating in the design and implementation of this recommendation.

- *Recommendation 6*

The Northern Territory Government implements an awareness and education program on unconventional gas industry regulation that informs affected communities about the approval process and their rights under the applicable statutory processes including access to land.

Origin agrees in-principle with this recommendation and looks forward to participating in the design and implementation of this recommendation.

- *Recommendation 7*

Shale gas development proponents build, own and maintain relationships with communities and are involved in consultation and the compilation of social baselines supported by independent consultants and technical experts.

Origin agrees with this recommendation and recognises the importance and significance of separating proponents' own engagement with its affected stakeholders from that of the role it will play in participating in the independently executed socio-economic knowledge base engagement. Origin also considers the role of the Northern Land Council to be vital in the compilation of social baselines.

Recommendation 8	Aboriginal community engagement adopts a structured approach that incorporates preparatory meetings, dialogue on social values, industry awareness and education meetings, project-specific meetings covering proposed development and implementation issues. The meetings are timed and structured to accommodate the needs of each community noting the different issues confronting communities including the potential need for interpreters.

Origin agrees with the intent of this recommendation - and notes that in many cases the current engagement processes required by existing Exploration Agreements between the company, host Traditional Owners and the representative Land Council, would satisfy this recommendation.

Recommendation 9	Independent monitoring and evaluation is implemented and designed to differentiate industry-related impacts from other impacts and identify the extent to which industry-related impacts exacerbate or ameliorate other impacts. The CSIRO's principles for a 'social license to operate' measurement and modelling framework are incorporated in the design of the monitoring and evaluation program.

Origin agree with the intent of this recommendation however we make the observation that, by our interpretation, there is reference to two different streams of assessment, that is - the CSIRO methodology represents as 'public sentiment polling' which is acceptable in its own right for the purpose of tracking public attitudes towards hydraulic fracture stimulation. We request however that it be acknowledged and agreed that this type of work does not constitute material social impact monitoring which monitors the actual material (socio-economic) changes in people's lives.

Recommendation 10	Social programs and mitigation strategies are to be adaptive and able to be refined to accommodate the findings of monitoring and evaluation of programs and initiatives.

Origin agrees in-principle with the intent of this recommendation.

Recommendation 11	Novel approaches, including those proposed by CSRM (2017), to the distribution of benefits (relative to impacts) are investigated to ensure equity within and between communities.

On the assumption that this recommendation seeks to ensure sensible and early consideration of achieving equitably distribution, then Origin agrees with the intent of this recommendation. However, Origin does not consider it the place of Government nor the operator to interfere or intervene with how Traditional Owners benefits are distributed. Secondly we consider it the business of the Northern Territory government to appropriate benefits from future royalties to the Territory. As such we consider that this recommendation requires substantially more work and investigation.

Report 1 - CSIRO 'Social License' Report

The CSIRO 'Social License' Report focussed on a measurement and modelling framework for SLO and we Origin provide comment on the following principles of the framework development.

- *Principle 1* — The engagement of a trusted third party – CSIRO's Gas Industry Social and Economic Research Alliance (GISERA) offers one such model.

Origin's view is that CSIRO is recognised as having one of the highest 'trust profiles' in Australia and is regarded as a credible and capable independent institution. Origin therefore support this principle.

- *Principle 2* — Protection of community rights and safety – ethical and privacy standards are applied under the National Statement on Ethical Conduct in Human Research (2015), placing the safety of participants first.

Origin's agrees with this principle in its entirety.

- *Principle 3* — Longitudinal design – placing the experiences of community at the centre of the process, and to identify issues before they become conflicts.

On the basis that our interpretation of community is defined as 'directly impacted stakeholders', Origin's agree with this principle and consider it vital and appropriate that they are placed as the primary, first and foremost individuals and / or groups at the core of the longitudinal design, radiating out through to indirectly impacted individuals and / or groups to more distal stakeholders.

- *Principle 4* — Accessibility of data – transparency of process and data provision back to community and other stakeholders in central to building trust that this is a vehicle for community voice.

Origin agrees with this principle and consider it essential to building trust and maintaining mutually beneficial relationships and two way communication channels.

- *Principle 4* — Inclusiveness of process – it is important that vulnerable, marginalised and special status groups are included in SLO research using appropriate methods.

Origin agrees with this principle and considers it important to co-design fit-for-purpose engagement mechanisms that accurately measure marginalised groups. We look forward to having the opportunity to participate in the design work associated with this principle.

Report 3 - CSRM Social Impact Assessment (SIA) Framework Report

Key Findings

1. Strategic assessment is needed for a program of development. The strategic assessment would clearly identify the objectives of the program and define the scale (and staging) of development in terms of balancing economic, social and environmental impacts at local, Territory and national scales.

Subject to comprehensive governance / oversight, Origin agrees in-principle and consider this finding important in yielding maximum collective benefit. Origin agrees with the ToR and considers highly competent multi-disciplinary social science practitioners, including micro-economic expertise as being fundamental to achieving success.

2. A strategic regional approach is needed that aligns individual projects and their outcomes with the objectives of the NT Economic Development Framework, regional planning objectives and community values and aspirations.

Origin agrees in-principle and consider this finding important in yielding maximum collective benefit in a planned and purposeful way.

3. Coordination and collaboration between multiple projects is needed in order to minimise negative cumulative impacts, minimise the 'footprint' of the industry in the placing of associated infrastructure (including workers 'accommodation) and maximise long term social and economic benefits to local and regional communities. Particular attention to human rights issues, and the rights and vulnerabilities of all Aboriginal peoples, (not only those recognised as Traditional Owners).

Origin agrees in-principle and considers this finding important in minimising the footprint of the industry and maximising co-existence opportunities that yield collective benefit across multiple industries.

Origin makes the observation that human rights considerations are correct and necessary acknowledgements though caution on this element becoming a central focal point prior to the completion of the SIA.

Origin makes the observation that caution also be exercised in characterising Aboriginal groups as universally vulnerable. Our experiences evidence Aboriginal peoples as resilient, unique and deserving of central recognition it their own right. Groups of customary 'sit down' rights, ethnologically determined to a project area, are primary and central - and groups with customary 'walking through' rights are also important. The connectivity of Aboriginal groups should be carefully mapped, agreed and reconciled into complementing agreements.

4. Particular attention to human rights issues, and the rights and vulnerabilities of all Aboriginal peoples, (not only those recognised as Traditional Owners).

As commented for Key Finding 3 - Origin makes the observation that human rights considerations are correct and necessary acknowledgements though caution on this element becoming a central focal point prior to the completion of the SIA.

Origin makes the observation that caution also be exercised in characterising Aboriginal groups as universally vulnerable. Our experiences evidence Aboriginal peoples as resilient, unique and deserving of central recognition it their own right. Groups of customary 'sit down' rights, ethnologically determined to a project area, are primary and central - and groups with customary 'walking through' rights are also important. The connectivity of Aboriginal groups should be carefully mapped, agreed and reconciled into complementing agreements.

5. Particular attention to psycho-social impacts, in recognition of the interconnectedness of personal, cultural and environmental integrity for Aboriginal peoples. Also, in recognition of the potentially stressful nature of land access agreements for pastoralists.

Origin agrees in-principle.

6. An independently led social baseline assessment, using ‘agreed indicators’ to measure impacts, ongoing social performance of the industry and sustainability outcomes (the indicators should be selected in consultation with local people and stakeholders).

Origin agrees in-principle.

7. An independently led community engagement program with affected stakeholder groups to discern the significance of impacts and to co-develop acceptable and appropriate mitigation and enhancement strategies.

Origin preserves the right of project proponents to hold primacy in ‘engagement’ with affected groups. Generally speaking this is achieved through the prescribed process of agreement making - carried out in conjunction with the prescribed statutory representative body / Land Council. Origin agrees in-principle with the inclusion of supplementary, independent and participatory monitoring.

8. The SIA framework should contribute to an open data policy with regular reporting on the social, economic and environmental performance of the shale gas industry.

Origin agrees in-principle.

9. Each additional project should provide an adaptive SIA risk assessment that specifically addresses cumulative impacts and its contribution to the development program’s objectives.

Origin agrees in-principle.

Statement D - Certificate of Analysis, SGS Chartered Chemists

A.B.N. 44 000 964 278
10 / 585 Blackburn Road
Notting Hill, Vic, 3168
Telephone: (03) 9574 3200

Chartered Chemists

REPORT NUMBER: M162147R2

Site/Client Ref: Daly Waters Well Sampling

Order No: 16270530

22-Dec-2016

Origin Energy

Level 6 /135 Coronation Drive
Milton

Queensland 4064
Attention: Matt Kernke

CERTIFICATE OF ANALYSIS

This report replaces previous report dated 2-Dec-2016

SAMPLES:	Nine samples were received for analysis
DATE RECEIVED:	**17-Nov-2016**
DATE COMMENCED:	**17-Nov-2016**
METHODS:	See Attached Results
RESULTS:	Please refer to attached pages for results.

Note: Results are based on samples as received at SGS laboratories

This replacement report includes amended Hg results reported as ng/m3.

Air free calculations was performed for General gases.

REPORTED BY:

Michael Jeddou
Senior Chemist

NATA Accredited Laboratory Number: 14429

Accredited for compliance
with ISO/IEC 17025.

The sampling for the samples in this report was carried out in accordance with SGS's NATA accredited sampling methods

NATA accreditation does not cover the performance of Method(s) - MA-1567; MA-1555

ANALYTICAL RESULTS

Matrix: Gas
Method: MA-1567 Field Test Results
Units as listed

Test Started:

Analyte Name		
	Leeder ID	2016027685
	Client ID	AMUNGEE NW-1H
	Sampled Date	15/11/2016
	PQL	
Field Mercury (ng/m3)	0.01	6600

Matrix: Gas
Method: MA-1555.AIR.01
Sample units are expressed in Bq/m³

Test Started:

Analyte Name		
	Leeder ID	2016027685
	Client ID	AMUNGEE NW-1H
	Sampled Date	15/11/2016
	PQL	
Radon 222		225

Matrix: Gas Bag
Method: MA-1105.AIR.05 General Gases
Sample units are expressed in Normalised Mol %

Test Started: 17/11/2016

Analyte Name				
	Leeder ID	2016027686	2016027687	2016027688
	Client ID	AMUNGEE NW-1H	AMUNGEE NW-1H Field dup	AMUNGEE NW-1H
	Sampled Date	15/11/2016	15/11/2016	
	PQL			Duplicate
Methane	0.01	91.24	91.04	91.23
Nitrogen	0.01	1.3	1.6	1.2
Carbon Dioxide	0.01	4.4	4.3	4.4
Ethane	0.01	2.9	2.8	2.9
Propane	0.01	0.11	0.11	0.11
n-Butane	0.01	nd	nd	nd
n-Pentane	0.01	nd	nd	nd
Hexanes	0.01	nd	nd	nd
Hydrogen	0.01	0.01	0.01	0.01
Helium	0.01	0.10	0.10	0.10
Carbon Monoxide	0.01	nd	nd	nd
Average Molecular Weight	0.1	17.9	17.9	17.9

ANALYTICAL RESULTS

Matrix: Canister
Method: MA-1113.AIR.02 Sulphur Gases (ppb)
Sample units are expressed in ppb

Test Started: 28/11/2016

	Leeder ID	2016027689
	Client ID	AMUNGEE NW-1H SC1119
Analyte Name	Sampled Date	15/11/2016
	PQL	
Hydrogen Sulphide	50	10000
Carbonyl Sulphide	50	nd
Methyl Mercaptan	50	nd
Ethyl Mercaptan	50	nd
Dimethyl Sulfide	50	nd
n-Propyl Mercaptan	50	nd
Thiophene	50	nd
n-Butyl Mercaptan	50	nd
Tetrahydrothiophene	50	nd

Matrix: Canister
Method: MA-1113.AIR.02 Sulphur Gases (ppb)
Sample units are expressed in ppb

Test Started: 28/11/2016

	Leeder ID	2016027690	2016027691	2016027692
	Client ID	AMUNGEE NW-1H Field dup SC1109	AMUNGEE NW-1H SC1119	Method
Analyte Name	Sampled Date	15/11/2016		
	PQL		Duplicate	Blank
Hydrogen Sulphide	50	5000	10000	nd
Carbonyl Sulphide	50	nd	nd	nd
Methyl Mercaptan	50	nd	nd	nd
Ethyl Mercaptan	50	nd	nd	nd
Dimethyl Sulfide	50	nd	nd	nd
n-Propyl Mercaptan	50	nd	nd	nd
Thiophene	50	nd	nd	nd
n-Butyl Mercaptan	50	nd	nd	nd
Tetrahydrothiophene	50	nd	nd	nd

Matrix: Canister
Method: MA-1113 Total Sulphur Gases (ppbv)
Sample units are expressed in ppbv

Test Started: 28/11/2016

	Leeder ID	2016027689
	Client ID	AMUNGEE NW-1H SC1119
Analyte Name	Sampled Date	15/11/2016
	PQL	
Total Reduced Sulphur Gases as	50	10000
Total Sulphur Gases as S	50	10000

ANALYTICAL RESULTS

Matrix: Canister
Method: MA-1113 Total Sulphur Gases (ppbv)
Sample units are expressed in ppbv

Test Started: 28/11/2016

	Leeder ID	2016027690	2016027691	2016027692
	Client ID	AMUNGEE NW-1H Field dup SC1109	AMUNGEE NW-1H SC1119	Method
Analyte Name	**Sampled Date**	15/11/2016		
	PQL		Duplicate	Blank
Total Reduced Sulphur Gases as	50	5000	10000	nd
Total Sulphur Gases as S	50	5000	10000	nd

ANALYTICAL RESULTS

Matrix: Thermal Desorption Tube
Method: TO-17.01 Volatile Organics (w/v)
Sample units are expressed in µg/m³

Test Started: 21/11/2016

	Leeder ID	2016027693
	Client ID	AMUNGEE NW-1H Mi160415
Analyte Name	**Sampled Date**	15/11/2016
	PQL	
Benzene		260
Bromobenzene		<5
Bromochloromethane		<5
Bromodichloromethane		<5
n-Butylbenzene		<5
sec-Butylbenzene		<5
tert-Butylbenzene		<5
Carbon tetrachloride		<5
Chlorobenzene		<5
Chloroethane		<5
Chloromethane		<5
2-Chlorotoluene		<5
4-Chlorotoluene		<5
1,2-Dibromo-3-chloropropane		<5
Dibromochloromethane		<5
1,2-Dibromoethane		<5
Dibromomethane		<5
1,2-Dichlorobenzene		<5
1,3-Dichlorobenzene		<5
1,4-Dichlorobenzene		<5
Dichlorodifluoromethane		<5
1,2-Dichloroethane		<5
1,1-Dichloroethane		<5
1,1-Dichloroethene		<5
cis-1,2-Dichloroethene		<5
trans-1,2-Dichloroethene		<5
1,2-Dichloropropane		<5
1,3-Dichloropropane		<5
2,2-Dichloropropane		<5
1,1-Dichloropropene		<5
cis-1,3-Dichloropropene		<5
trans-1,3-Dichloropropene		<5
Ethylbenzene		10
Hexachlorobutadiene		<5
Isopropylbenzene		<5
4-Isopropyltoluene		<5
Naphthalene		<5
Propylbenzene		<5
Styrene		<5
1,1,1,2-Tetrachloroethane		<5

ANALYTICAL RESULTS

Matrix: Thermal Desorption Tube
Method: TO-17.01 Volatile Organics (w/v)
Sample units are expressed in µg/m³

Test Started: 21/11/2016

	Leeder ID	2016027693
	Client ID	AMUNGEE NW-1H Mi160415
Analyte Name	Sampled Date	15/11/2016
	PQL	
1,1,2,2-Tetrachloroethane		<5
Tetrachloroethene		<5
Toluene		160
Tribromomethane		<5
1,2,3-Trichlorobenzene		<5
1,2,4-Trichlorobenzene		<5
1,1,1-Trichloroethane		<5
1,1,2-Trichloroethane		<5
Trichloroethene		<5
Trichlorofluoromethane		<5
Trichloromethane		<5
1,2,3-Trichloropropane		<5
1,2,4-Trimethylbenzene		8.1
1,3,5-Trimethylbenzene		<5
Vinyl chloride		<5
o-Xylene		13
m&p-Xylenes		24

ANALYTICAL RESULTS

Matrix: Thermal Desorption Tube
Method: TO-17.01 Volatile Organics (w/v)
Sample units are expressed in µg/m³

Test Started: 21/11/2016

	Leeder ID	2016027695
	Client ID	AMUNGEE NW-1H Field dup Mi180121
Analyte Name	Sampled Date	15/11/2016
	PQL	
Benzene		270
Bromobenzene		<5
Bromochloromethane		<5
Bromodichloromethane		<5
n-Butylbenzene		<5
sec-Butylbenzene		<5
tert-Butylbenzene		<5
Carbon tetrachloride		<5
Chlorobenzene		<5
Chloroethane		<5
Chloromethane		<5
2-Chlorotoluene		<5
4-Chlorotoluene		<5
1,2-Dibromo-3-chloropropane		<5
Dibromochloromethane		<5
1,2-Dibromoethane		<5
Dibromomethane		<5
1,2-Dichlorobenzene		<5
1,3-Dichlorobenzene		<5
1,4-Dichlorobenzene		<5
Dichlorodifluoromethane		<5
1,2-Dichloroethane		<5
1,1-Dichloroethane		<5
1,1-Dichloroethene		<5
cis-1,2-Dichloroethene		<5
trans-1,2-Dichloroethene		<5
1,2-Dichloropropane		<5
1,3-Dichloropropane		<5
2,2-Dichloropropane		<5
1,1-Dichloropropene		<5
cis-1,3-Dichloropropene		<5
trans-1,3-Dichloropropene		<5
Ethylbenzene		9.5
Hexachlorobutadiene		<5
Isopropylbenzene		<5
4-Isopropyltoluene		<5
Naphthalene		<5
Propylbenzene		<5
Styrene		<5
1,1,1,2-Tetrachloroethane		<5

ANALYTICAL RESULTS

Matrix: Thermal Desorption Tube
Method: TO-17.01 Volatile Organics (w/v)
Sample units are expressed in µg/m³

Test Started: 21/11/2016

	Leeder ID	2016027695
	Client ID	AMUNGEE NW-1H Field dup Mi180121
Analyte Name	**Sampled Date**	15/11/2016
	PQL	
1,1,2,2-Tetrachloroethane		<5
Tetrachloroethene		<5
Toluene		170
Tribromomethane		<5
1,2,3-Trichlorobenzene		<5
1,2,4-Trichlorobenzene		<5
1,1,1-Trichloroethane		<5
1,1,2-Trichloroethane		<5
Trichloroethene		<5
Trichlorofluoromethane		<5
Trichloromethane		<5
1,2,3-Trichloropropane		<5
1,2,4-Trimethylbenzene		<5
1,3,5-Trimethylbenzene		<5
Vinyl chloride		<5
o-Xylene		11
m&p-Xylenes		19

Report N°: M162147R2

ANALYTICAL RESULTS

Matrix: Thermal Desorption Tube
Method: TO-17.02 Volatile Organics
Sample units are expressed in ng/tube

Test Started: 21/11/2016

Leeder ID		2016027697	2016027698
Client ID		Trip Blank Mi101224	Method Blank
Analyte Name	**Sampled Date**		
	PQL		
Benzene	5	nd	nd
Bromobenzene	5	nd	nd
Bromochloromethane	5	nd	nd
Bromodichloromethane	5	nd	nd
n-Butylbenzene	5	nd	nd
sec-Butylbenzene	5	nd	nd
tert-Butylbenzene	5	nd	nd
Carbon tetrachloride	5	nd	nd
Chlorobenzene	5	nd	nd
Chloroethane	5	nd	nd
Chloromethane	5	nd	nd
2-Chlorotoluene	5	nd	nd
4-Chlorotoluene	5	nd	nd
1,2-Dibromo-3-chloropropane	5	nd	nd
Dibromochloromethane	5	nd	nd
1,2-Dibromoethane	5	nd	nd
Dibromomethane	5	nd	nd
1,2-Dichlorobenzene	5	nd	nd
1,3-Dichlorobenzene	5	nd	nd
1,4-Dichlorobenzene	5	nd	nd
Dichlorodifluoromethane	5	nd	nd
1,2-Dichloroethane	5	nd	nd
1,1-Dichloroethane	5	nd	nd
1,1-Dichloroethene	5	nd	nd
cis-1,2-Dichloroethene	5	nd	nd
trans-1,2-Dichloroethene	5	nd	nd
1,2-Dichloropropane	5	nd	nd
1,3-Dichloropropane	5	nd	nd
2,2-Dichloropropane	5	nd	nd
1,1-Dichloropropene	5	nd	nd
cis-1,3-Dichloropropene	5	nd	nd
trans-1,3-Dichloropropene	5	nd	nd
Ethylbenzene	5	nd	nd
Hexachlorobutadiene	5	nd	nd
Isopropylbenzene	5	nd	nd
4-Isopropyltoluene	5	nd	nd
Naphthalene	5	nd	nd
Propylbenzene	5	nd	nd
Styrene	5	nd	nd
1,1,1,2-Tetrachloroethane	5	nd	nd

ANALYTICAL RESULTS

Matrix: Thermal Desorption Tube
Method: TO-17.02 Volatile Organics
Sample units are expressed in ng/tube

Test Started: 21/11/2016

	Leeder ID	2016027697	2016027698
	Client ID	Trip Blank Mi101224	Method
Analyte Name	**Sampled Date**		
	PQL		Blank
1,1,2,2-Tetrachloroethane	5	nd	nd
Tetrachloroethene	5	nd	nd
Toluene	5	nd	nd
Tribromomethane	5	nd	nd
1,2,3-Trichlorobenzene	5	nd	nd
1,2,4-Trichlorobenzene	5	nd	nd
1,1,1-Trichloroethane	5	nd	nd
1,1,2-Trichloroethane	5	nd	nd
Trichloroethene	5	nd	nd
Trichlorofluoromethane	5	nd	nd
Trichloromethane	5	nd	nd
1,2,3-Trichloropropane	5	nd	nd
1,2,4-Trimethylbenzene	5	nd	nd
1,3,5-Trimethylbenzene	5	nd	nd
Vinyl chloride	5	nd	nd
o-Xylene	5	nd	nd
m&p-Xylenes	5	nd	nd

QA/QC RESULTS

Matrix: Gas Bag
Method: MA-1105.AIR.05 General Gases
Quality Control Results are expressed in Percent Recovery of expected result   Test Started: 17/11/2016

Analyte Name	Leeder ID / Client ID / Sampled Date / PQL	2016027699 Method Spike	2016027700 Method Spike Dup
Nitrogen		98	97
Carbon Dioxide		98	97
Ethane		99	99
Propane		99	99
n-Butane		97	96
Carbon Monoxide		98	98

Matrix: Thermal Desorption Tube
Method: TO-17.02 Volatile Organics
Quality Control Results are expressed in Percent Recovery of expected result   Test Started: 21/11/2016

Analyte Name	Leeder ID / Client ID / Sampled Date / PQL	2016027703 Method Spike
Benzene		97
Bromodichloromethane		96
Carbon tetrachloride		92
Chlorobenzene		97
Dibromochloromethane		99
1,2-Dichlorobenzene		98
1,3-Dichlorobenzene		95
1,4-Dichlorobenzene		94
1,2-Dichloroethane		102
1,1-Dichloroethene		79
cis-1,2-Dichloroethene		89
trans-1,2-Dichloroethene		87
1,2-Dichloropropane		102
Ethylbenzene		99
Styrene		100

QA/QC RESULTS

Matrix: Thermal Desorption Tube
Method: TO-17.02 Volatile Organics
Quality Control Results are expressed in Percent Recovery of expected result — Test Started: 21/11/2016

Analyte Name	Leeder ID / Client ID / Sampled Date / PQL	2016027703 Method Spike
Tetrachloroethene		95
Toluene		97
Tribromomethane		102
1,2,4-Trichlorobenzene		93
1,1,1-Trichloroethane		96
1,1,2-Trichloroethane		104
Trichloroethene		97
Trichloromethane		106
o-Xylene		98
m&p-Xylenes		99

Matrix: Thermal Desorption Tube
Method: TO-17.02 Volatile Organics
Quality Control Results are expressed in Percent Recovery of expected result — Test Started: 21/11/2016

Analyte Name	Leeder ID / Client ID / Sampled Date / PQL	2016027704 Method Spike Dup
Benzene		97
Bromodichloromethane		97
Carbon tetrachloride		92
Chlorobenzene		97
Dibromochloromethane		99
1,2-Dichlorobenzene		100
1,3-Dichlorobenzene		96
1,4-Dichlorobenzene		96
1,2-Dichloroethane		103
1,1-Dichloroethene		80
cis-1,2-Dichloroethene		91
trans-1,2-Dichloroethene		89
1,2-Dichloropropane		104
Ethylbenzene		100
Styrene		101

QA/QC RESULTS

Matrix: Thermal Desorption Tube
Method: TO-17.02 Volatile Organics
Quality Control Results are expressed in Percent Recovery of expected result

Test Started: 21/11/2016

Analyte Name	PQL	2016027704 Method Spike Dup
Leeder ID		2016027704
Client ID		Method
Sampled Date		
	PQL	Spike Dup
Tetrachloroethene		97
Toluene		98
Tribromomethane		102
1,2,4-Trichlorobenzene		97
1,1,1-Trichloroethane		96
1,1,2-Trichloroethane		104
Trichloroethene		96
Trichloromethane		106
o-Xylene		100
m&p-Xylenes		100

QUALIFIERS / NOTES FOR REPORTED RESULTS

PQL	Practical Quantitation Limit
nd	Not Detected – The analyte was not detected above the reported PQL.
is	Insufficient Sample to perform this analysis.
T	Tentative identification based on computer library search of mass spectra.
NC	Not calculated and/or Results below PQL
NV	No Vacuum, Canister received above standard atmospheric pressure
nr	Not Requested for analysis.
R	Rejected Result – results for this analysis failed QC checks.
SQ	Semi-Quantitative result – quantitation based on a generic response factor for this class of analyte.
IM	Inappropriate method of analysis for this compound
U	Unable to provide Quality Control data – high levels of compounds in sample interfered with analysis of QC results.
UF	Unable to provide Quality Control data- Surrogates failed QC checks due to sample matrix effects
L	Analyte detected at a level above the linear response of calibration curve.
E	Estimated result. NATA accreditation does not cover estimated results.
C1	These compounds co-elute.
--	Parameter Not Determined
CT	Elevated concentration. Results reported from carbon tube analysis
**	Sample shows non-petroleum hydrocarbon profile

APPENDIX ONE.

CHAIN OF CUSTODY DOCUMENT

SGS

TO-15 Canister Chain of Custody Record

Dispatch samples to: Unit 10/585 Blackburn Road, Notting Hill, Victoria 3168, Australia

Attn: Sample Reception - Contact Ph: +613 9574 3311

Email: au.samplereceipt.mitcham@sgs.com

PAGE 1 OF 1

ENT NAME:	Origin Energy	CONTACT PHONE No:	0467700 565
ENT ADDRESS:	Level 5 135 Coronation Dr, Milton	CONTACT FAX No:	
	QLD 4064	RESULTS REQUIRED BY:	STAT
N:		EMAIL REPORT TO:	matt.kernke@upstream.originenergy.com.au
NTACT:	Matt Kernke		
MPLED BY:	BH	LAB QUOTE NUMBER:	AQ21610802.KH Rev1
ENT PROJECT REF:	M162147	PURCHASE ORDER NUMBER:	

Client Sample ID (Field Location)	Canister #	FlexFoil Gas Bag/ Gas Cylinder	Carbon Tube #	Carbon Tube Sample Volume	Leak Test Passed	Date of Collection	Time of Collection	Field Measurements			Canister Pressure/Vacuum		Analysis Requested					
								Radon (Bq/m3)	H2S (ppm)	Mercury Vapour ~~(ug/m³)~~	Inital ~~MH~~ 1/12/16	Final		Sulphur compounds	Gas Composition	TO-17		
AMUNGEE NW-1H		Bag				15-11-16	8.30	~~225~~	7	6562	ng/m³				x			
AMUNGEE NW-1H	x SC1119				Pass	15-11-16	8.30	225			-30	0		x				
AMUNGEE NW-1H			x Mi 166405	1L		15-11-16	8.30									x		
AMUNGEE NW-1H			x Mi 180121	1L		15-11-16	8.30									x		
AMUNGEE NW-1H			x Mi 180118	0.2L		15-11-16	8.30									x		
AMUNGEE NW-1H			x Mi 155274	0.2L		15-11-16	8.30									x		
Trip Blank			x Mi 101224													x		
MUNGEE NW-1H DUP		Bag				15-11-16	8.30								x			
MUNGEE NW-1H DUP	x SC1109				Pass	15-11-16	8.30				-30	0		x				

Notes: Analysis as per quote attached.

Un-used cannister 1120

	(Name)	(Signature)	(Date / Time)
LEASED BY:	B.harbort	BHarbort	16-11-16
CEIVED BY:	Lyndall Stevens	[signature]	17/11/16 10:30am

Reference Attachment A - BC Oil and Gas Commission 2014

Investigation of Observed Seismicity in the Montney Trend

Investigation of Observed Seismicity in the Montney Trend

December 2014

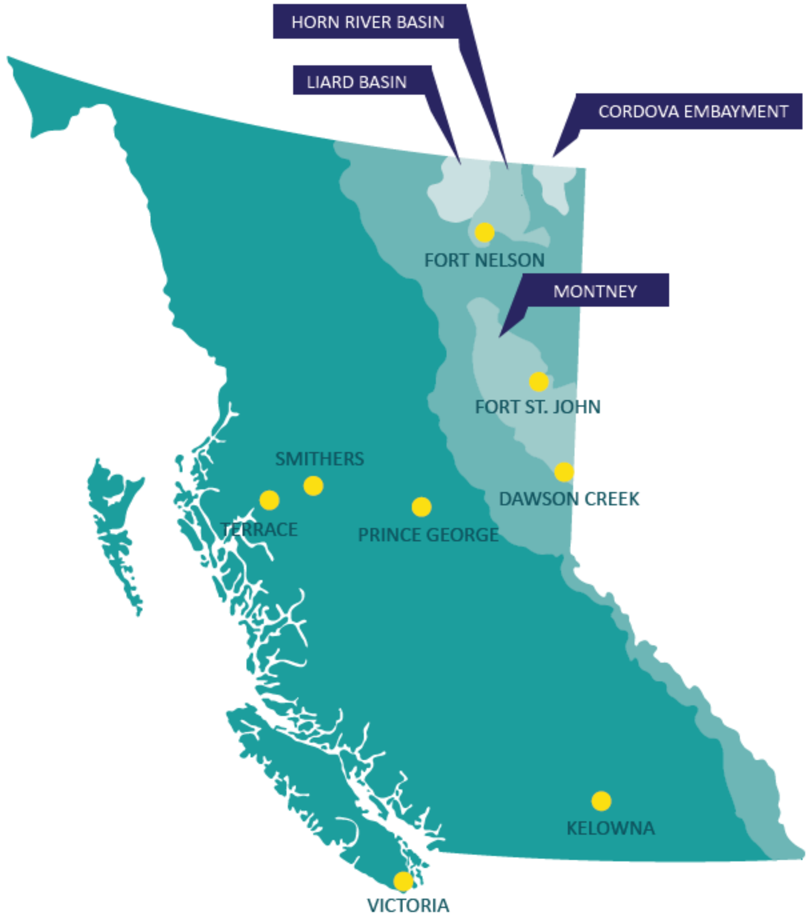
BC Oil & Gas COMMISSION

ABOUT THE COMMISSION

The BC Oil and Gas Commission is the single-window regulatory agency with responsibilities for regulating oil and gas activities in B.C., including exploration, development, pipeline transportation and reclamation.

The Commission's core services include reviewing and assessing applications for industry activity, consulting with First Nations, cooperating with partner agencies, and ensuring industry complies with provincial legislation and all regulatory requirements. The public interest is protected by ensuring public safety, respecting those affected by oil and gas activities, conserving the environment, and ensuring equitable participation in production.

For general information about the Commission, please visit www.bcogc.ca or phone 250-794-5200. For specific inquiries regarding this report, please contact ogc.communications@bcogc.ca.



Commission Offices &
B.C.'s Major Natural Gas Plays

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Terms Used in this Report

Cluster
A group of seismic events linked to a common trigger mechanism. Usually these events are closely spaced in both area and time.

Dense Seismograph Array (Dense Array)
A localized array of seismographs with a minimum of three stations, deployed to monitor for induced seismicity in a particular area. These arrays are capable of locating event hypocentres to within 500 metres and recording magnitudes down to Magnitude 1.0.

Hypocentre
The point within the earth where an earthquake starts. Hypocentres include both the horizontal surface location and depth of an event.

Induced Seismicity
Earthquakes (events) resulting from human activity.

Microseismic
Describes both the recording and processing of very low magnitude events produced by hydraulic fracturing. Typically, these events range from -3.0 to 0.5 M_L.

Richter Magnitude (M_L) and Moment Magnitude (M_w)
Seismic events reported to the Commission are in either M_L or M_w magnitudes. Both values are approximately equivalent in northeast B.C. This report uses M_L.

Seismicity
Recorded earthquakes caused primarily by fault movement. Typically refers to events greater than 0.5 M_L.

Stage
A hydraulically fractured interval along a horizontal wellbore. Each "stage" is isolated prior to the injection of fluids to hydraulically fracture the reservoir rock. Unconventional wells in the Montney average about 14 hydraulically fractured stages per wellbore.

ABOUT THE MONTNEY TREND

The Montney Trend (Montney) is a 29,850-square-kilometre underground siltstone formation that stretches from the B.C.-Alberta border near Dawson Creek 200 kilometres (km) northwest to the B.C. Rocky Mountain foothills (Figure 1). Its depth ranges from 1,200 to 3,200 metres (m) below the surface. Overall the Montney represents about 37 per cent of B.C.'s recoverable natural gas reserves at15.7 Trillion Cubic Feet. A cross-section diagram of the Montney is shown in Appendix 1.

Unconventional gas development in the Montney began in the mid-2000s, and by 2014 the region has become B.C.'s single most important natural gas producing area, accounting for 56 per cent of the province's daily production, with 75 per cent from unconventional sources.

The Montney currently has over 1,700 active natural gas wells, nearly all of which are horizontal wells drilled after 2005. In 2013, 80 per cent of wells drilled in B.C. were completed in the Montney, rising to 89 per cent by the end of August 2014. Daily production levels are presently 2.3 Billion Cubic Feet/day, and significant gas liquids and condensates are also being generated.

In order to support unconventional gas development in the Montney, there has been an increase in demand for wastewater disposal capacity. Since 2005, the number of active wastewater disposal wells has increased from 89 to 104, and disposal volumes have increased 60 per cent over the same period (Figure 2, next page). Much of the increase is attributable to disposal of flowback fluids from hydraulic fracturing operations. In B.C., water used for hydraulic fracturing must ultimately be disposed underground at an approved wastewater disposal well.

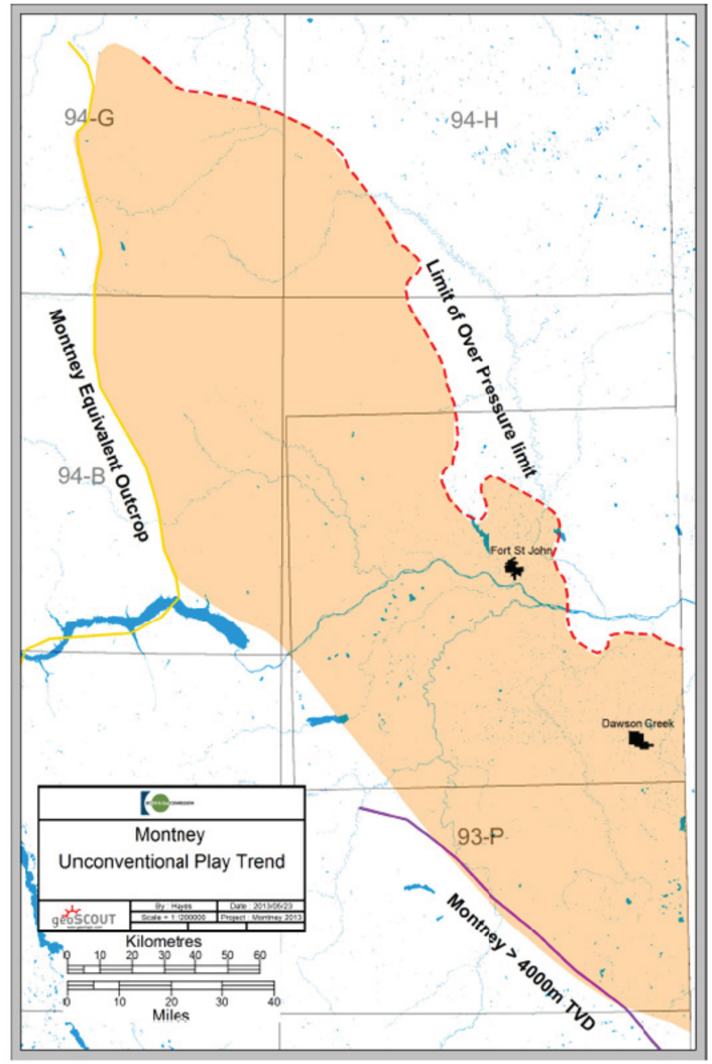
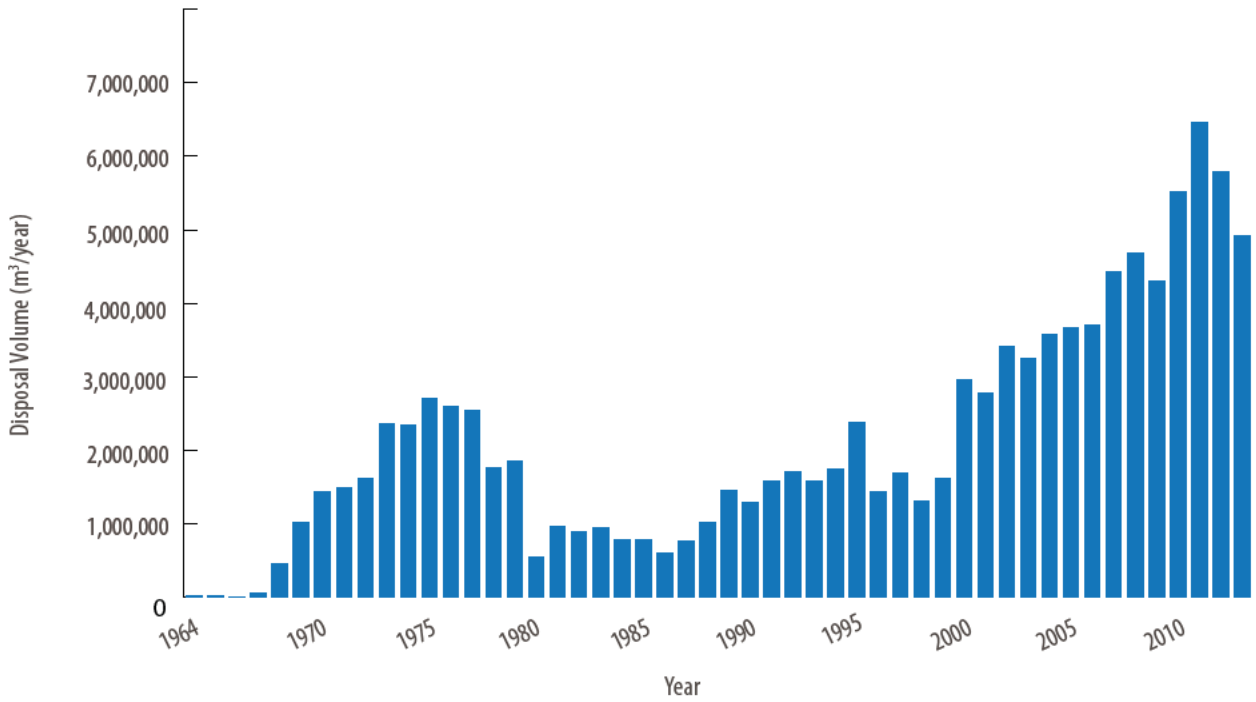


Figure 1 – The Montney Trend

Figure 2 – Annual Water Disposal Volumes for Northeast B.C.



Executive Summary

In 2012 the BC Oil and Gas Commission (Commission) released the results of its investigation into induced seismicity in the Horn River Basin. The report determined low-level seismic activity (2.2 to 3.8 M_L) was caused by fluid injection during hydraulic fracturing near pre-existing faults.[1] As noted in the 2012 report, the Commission distinguishes between the microseismic events caused by fracturing the rock during the hydraulic fracturing process (-3.0 to 0.5 M_L) and induced events caused by fault movement (events greater than 0.5 M_L).

As a result of recommendations from the investigation (Appendix 2), eight new seismograph stations (funded by the Commission, Geoscience BC, and the Canadian Association of Petroleum Producers) were added to the existing two Canadian National Seismograph Network (CNSN) stations to provide more accurate detection and location capabilities. Six went online in August 2013, and two in November 2014. With the new stations the CNSN began recording many more lower magnitude events than previously recorded, enhancing the Commission's ability to track seismicity. This report's primary focus is on the investigation into events recorded between August 2013 and October 2014 in the Montney.

The investigation found that during this period 231 seismic events in the Montney were attributed to oil and gas operations – 38 induced by wastewater disposal and 193 by hydraulic fracturing operations. None of the recorded events resulted in any injuries, property damage or loss of wellbore containment.

The report finds that events ranging from 2.5 to 4.4 M_L may produce actual fault movements in the range of one millimetre to centimetres within the target formation and at depth. Data also shows there is a higher occurrence of induced seismicity in certain areas due to the presence of pre-existing, stressed faults that are susceptible to reactivation.

As detailed in this report, the Commission identified five areas in the Montney where seismic events appear to have been triggered by hydraulic fracturing operations. Data shows that only 0.15 per cent of wellbore stage completions during the investigation period resulted in seismic events felt at surface.

Two additional areas of observed seismicity appear linked to two wastewater disposal wells. There are 104 active disposal wells in B.C.

1 Since release of the Horn River Basin Observed Seismicity Investigation report in August 2012 the Horn River and Liard Basins have been seismically quiet. Only four new seismic events have occurred in the basins over the past two years. This lack of recorded events, even after the upgrade to the CNSN, is believed to be due to a decline in the number of high-volume hydraulic fracturing operations.

Types of Induced Seismicity

Two types of induced seismicity are discussed in this report, wastewater disposal induced seismicity and hydraulic fracturing induced seismicity. In both types, the trigger mechanism is essentially the same – fluid is injected into or near an underground fault at high enough pressures for driving stresses to overcome normal stresses, resulting in fault movement. Although the trigger mechanism is the same, there are significant differences (Table 1).

Table 1 – Comparison of wastewater disposal induced seismicity to hydraulic fracturing induced seismicity

Comparison	Events triggered by fluid injection into wastewater disposal wells	Events triggered by fluid injection during hydraulic fracturing along horizontal wellbores
Injected Volumes	High cumulative volumes can be injected (typically over 100,000 m^3).	Injected volumes vary from 600 to 5,000 m^3 per stage.
Flowback	Injected fluid volume is not commonly flowed back from the target formation.	On average, 50 per cent of injected fluid volume is flowed back when a well is put into production.
Injection Point	Fluid injection is at a single point through a set of perforations in a vertical well.	The injection point changes as new hydraulic fracture stages are completed along a horizontal wellbore.
Injection Zone	Injection is into a fair to good quality reservoir or aquifer.	Injection is into an unconventional gas zone to fracture the rock. Fluid left behind after flowback stays either in pre-existing faults or fractures, or in the newly created fracture network.
Distance of Triggered Events	Distant fault movement, several kilometres away from the injection point, can be triggered by injection at the disposal well.	Triggered events are usually close to the injection point as wellbore stages intersect faults. In some cases deeper events, up to 800 m below the injection point (Skoumal, 2014) or events up to 500 m horizontally from the injection point, have been triggered.
Injection pressures	Injection rates and pressures can be controlled to mitigate seismicity. Injection pressure is regulated to remain below formation fracture pressure.	Injection pressures are designed to momentarily achieve breakdown pressure. This is usually well above fault re-activation pressure. Afterward, pressure falls to the lower treating pressure.
Seismic Correlation	Seismicity generally correlates to either injection rate/pressure or volume.	Seismicity does not appear to correlate to either injection rate or volume.

Seismic Monitoring in Northeast B.C.

The CNSN regional array is a reliable tool for locating new seismic event clusters and helping identify operations that may be triggering induced events. However, due to its spacing, it is incapable of providing accurate depths for events occurring in the upper crust.

To overcome this, dense seismograph arrays are used to provide more detailed locations. Dense array deployments collect accurate event locations and depths, and reliably record a wide range of magnitudes and detailed seismological data to monitor and mitigate induced seismic events.

The Commission ordered the deployment of three dense arrays in 2013 at Altares, Graham and Doe-Dawson (Figure 3). Dense arrays are required to have hypocentre resolution to within 500 m and magnitude detection capability to 1.5 M_L. Industry operators in northeast B.C. also voluntarily deployed several dense arrays, including one in Septimus and an 18-station dense array in the northern Montney.

Bi-weekly reports are submitted by operators of dense arrays ordered by the Commission, as well as from several of the arrays independently deployed by operators. The reports include dates, times, locations, depths, and magnitudes of all recorded events.

Responding to Seismic Events

The Commission tracks northeast B.C. seismic events through the Natural Resources Canada (NRCan) website and industry-owned dense seismographic arrays. Events reported by the public are also investigated.

The Commission compares these seismic events alongside the locations of oil and gas operations, including hydraulic fracturing. If there is a temporal and geographic similarity, operators are contacted with a request for more data, including stage times and parameters, and microseismic and dense seismograph array monitoring data if available.

Action is then taken if required, and steps may include requesting the deployment of dense seismograph arrays, or changes to hydraulic fracturing parameters, which can include limiting well pressures or suspending operations.

Seismic Event Summary and Analysis

The Commission identified five areas within the Montney where seismic events were linked to hydraulic fracturing operations (Figure 3). Two additional areas where seismicity has been observed (Graham and Pintail) appear linked to deeper, sub-Montney wastewater disposal and not hydraulic fracturing.

From Aug. 1, 2013 to Oct. 10, 2014, NRCan recorded 231 events in the Montney, ranging from 1.0 to 4.4 M_L, attributed to oil and gas activities. Thirty-eight of these events (1.2 to 2.9 M_L) were triggered by wastewater disposal wells at Graham and Pintail (Figure 4, next page). Another 193 events (1.0 to 4.4 M_L) were triggered by hydraulic fracturing operations in the Montney (Figure 5, next page). Event cluster maps with hydraulic fracturing times are shown in Appendix 3, and a summary of the clusters is detailed in Tables 2 and 3 (Page 12).

Currently 450 wells are completed in the Montney each year. These wells average 14 hydraulic fracture stages per wellbore, totaling about 7,500 hydraulic fracture stages for the investigation period. Injected volumes of hydraulic fracturing fluid range from about 700-3,500 m³ per stage, depending on area and operator. During the investigation period, hydraulic fracturing operations triggered 193 induced events. Therefore, approximately 2.6 per cent of pumped stages triggered events.

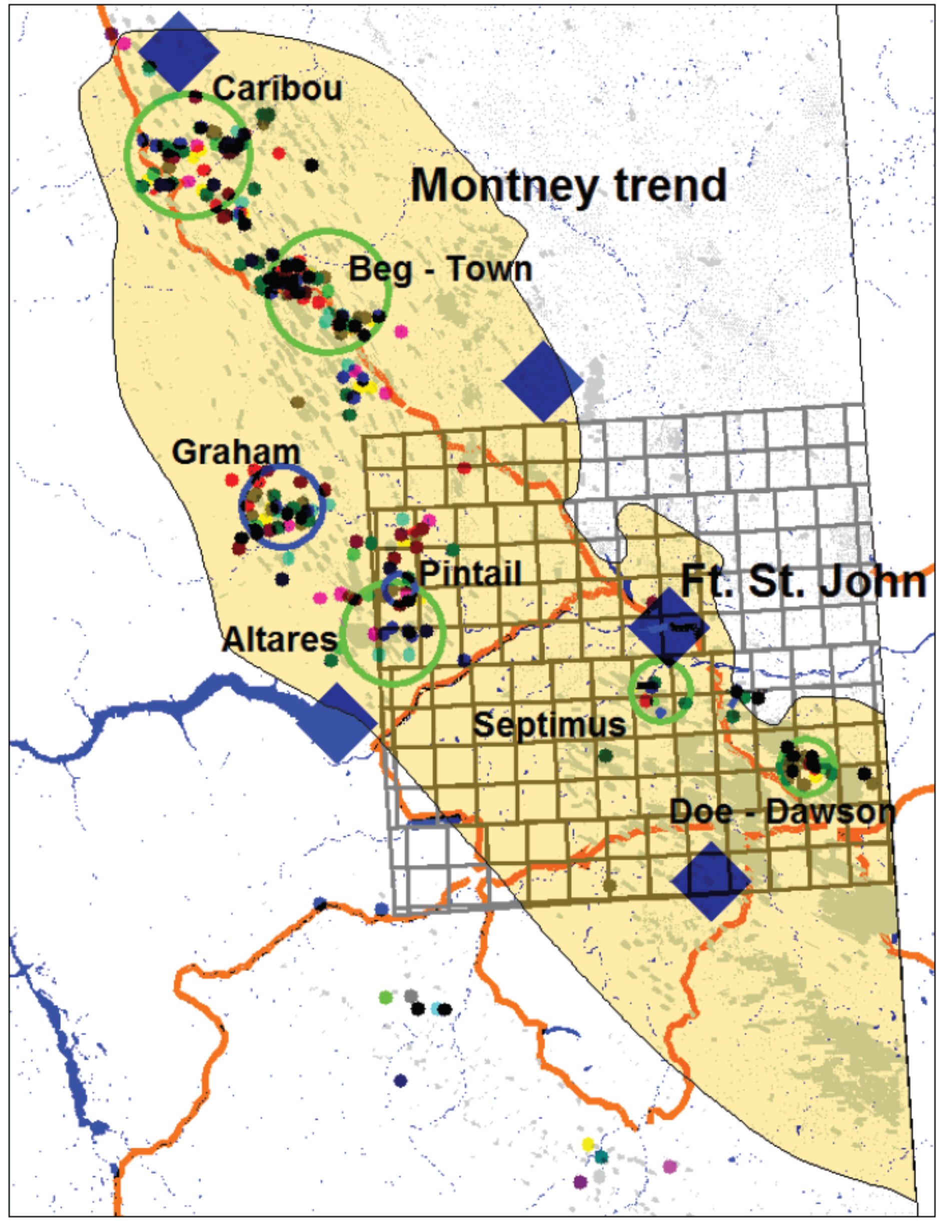


Figure 3 – The green circles on this map denote areas with hydraulic fracturing induced seismic events, and coloured dots represent NRCan events for Aug. 14, 2013 to Nov. 1, 2014. The two blue circles are wastewater disposal well induced seismicity areas. The blue diamonds are CNSN seismograph stations.

For wastewater disposal wells, of the 104 active in the province, only two have been linked to induced seismicity.

Recorded ground motions associated with these events shows they are below damage thresholds for surface structures and no injuries or property damages were reported. Data shows there is a higher occurrence of induced seismicity in the disturbed belt of the Rocky Mountain foothills and in proximity to the Fort St. John Graben complex. This is attributed to the presence of pre-existing, stressed faults that are susceptible to reactivation.

Hydraulic fracturing in the Lower Montney appears more prone to induced seismicity, although two events greater than 3.5 M_L have been recorded in the Upper Montney. Fluid injection at the Lower Montney level may reactivate older, underlying structures more readily than Middle and Upper Montney fracture stimulations. So far, dense array data has shown fault re-activation induced by hydraulic fracturing can occur within the Montney target zone or up to 700 m below the Montney as a result of fluid injection. On the horizontal plane, re-activation can occur within 100 to 400 m of the injection point.

Several instances of casing deformation have occurred within the horizontal portion of shale gas wellbores, but there was no loss of integrity with the wells and no impact on the vertical portions of wellbores.

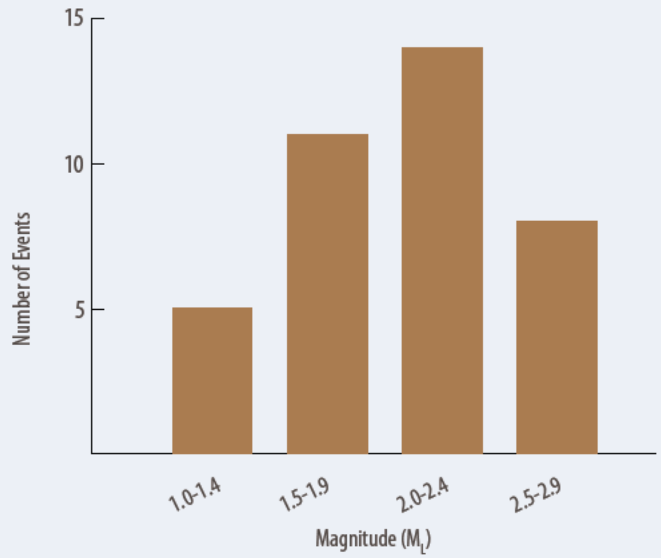


Figure 4 – Magnitude range frequency for wastewater disposal wells induced events

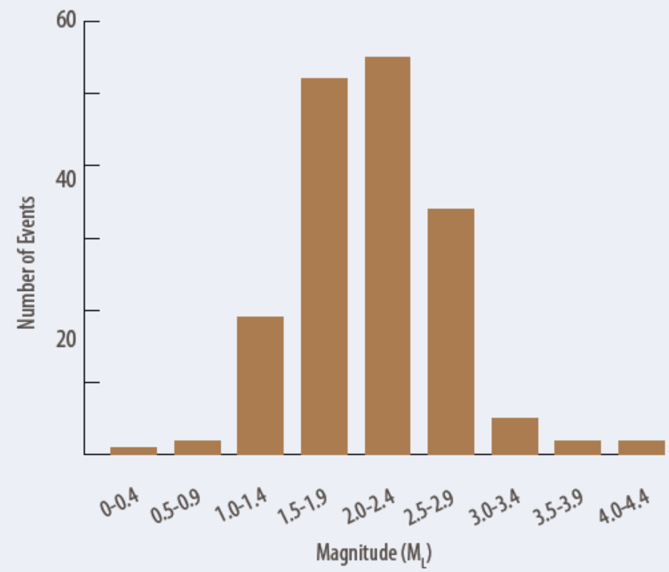


Figure 5 – Magnitude range frequency for hydraulic fracture induced events

Preliminary results indicate induced events triggered by injection at wastewater disposal wells may be mitigated by reducing disposal rate and pressure. Commission water disposal project approvals contain conditions limiting formation pressure to 120 per cent of original formation pressure.

Investigating Seismic Events

Determining whether a seismic event is induced is done by considering background seismicity, distance from hydraulic fracturing or disposal operations, and the timing of the event compared to the timing of operations.

As an example, for the Oct. 18-28, 2013 Doe-Dawson cluster (Appendix 3), there were no events previously recorded by the CNSN in that area. Ten events were located by the CNSN within five km of the 5-5-80-15W6 pad. These events were time coincident with hydraulic fracturing operations at the pad. There were no other active hydraulic fracturing or disposal operations within a five-km radius of the 5-5-80-15W6 pad.

Dense arrays provide precise event epicentres and depths, and often delineate the active fault. A strong case for induced seismicity can be made when mapped dense array hypocentres and event times are compared to hydraulic fracturing operational times.

Felt events have also been useful in verifying CNSN or dense array epicentres. Events greater than 3.5 M_L are often felt at the wellpad site with felt intensity dissipating away from the epicentre.

Table 2 – Summary of Montney Induced Seismic Event Clusters (Maps and graphs shown in Appendix 3)

Area	Cluster	Number of Events	Magnitudes	Dense Array (DA) coverage	Felt (Mercalli Scale)	Coincidence with hydraulic fracturing (HF)	Coincidence with water disposal operations	Distance from operations triggering events
1. Doe-Dawson	Oct. 18-28, 2013	16 NRCan events	1.2 to 2.8 M_L	Not at time of events; DA ordered	Yes – 6 felt events (III-IV)	All events occurred during or within 2 hours of HF	No evidence of wastewater induced activity	Within 3 km
2. Septimus	May 28, 2013	8 NRCan events	2.1 to 4.2 M_L	Not at time of events; DA ordered	Yes (III-IV)	All events occurred during or within 2 hours of HF	1 km from disposal well, cumulative 4,800 m^3 as of May 28. No evidence wastewater was trigger mechanism	Within 3 km
3. Altares	Nov. 5-6, 2013	14 DA events	1.2 to 2.2 M_L	Yes; DA monitoring HF	Yes (III-IV)	4 events within 2 hours of HF, 3 events during HF and 7 events within 7.5 hours of HF	No	Within 1 km
4. Beg-Town	Oct. 7-26, 2013	6 NRCan events	1.8 to 3.0 M_L	Not at time of events; DA now in place	None reported	Events vary from 2 hours to 12 days post-HF	No evidence of wastewater induced activity	1-3 km
5. Beg-Town	Aug. 18-31, 2013	10 NRCan events	1.5 to 3.4 M_L	Not at time of events; DA now in place	None reported	3 events occurred during HF. 3.0 ML event occurred 21 hours post HF	No evidence of wastewater induced activity.	1-3 km
6. Caribou	Jan. 15-23, 2014	9 NRCan events	1.3 to 3.0 M_L	Not at time of events; DA now in place	Yes (III-IV)	5 events occurred during or within 15 minutes of operations; 1 event 3 hours post-HF. 3 events within 48 hours	No evidence of wastewater induced activity	5 events within 1-3 km
7. Caribou	Mar. 2-13, 2014	11 NRCan events	1.2 to 3.2 M_L	Not at time of events; DA now in place	Yes (III-IV)	1 event occurred during HF. Other events 30 to 72 hours post-HF	No evidence of wastewater induced activity	500 m-3 km

Table 3 – Wastewater Disposal Induced Seismicity

Area	Cluster	#Events	Magnitudes	Dense Array Coverage	Felt	Coincidence with disposal operations	Distance
8. Pintail	Jan. 19, 2013 to present	5 NRCan events	2.9 to 3.1 M_L	DA in place	None reported	Events began six months after initiation of disposal	500 m-3 km
9. Graham	Mar. 2003 to present	>122 NRCan events	1.6 to 4.0 M_L	DA coverage since Mar. 2014	Yes (III-IV)	Events began 13 months after initiation of disposal	1-5 km of disposal well

Summary of Findings

- Induced seismicity has occurred in association with hydraulic fracturing in the Montney.
- Induced seismicity also occurred in association with two deep, sub-Montney wastewater disposal wells in northeast B.C.
- No injuries or property damage were linked to this induced seismicity. Ground motions recorded to date are below the damage threshold.
- There were no vertical wellbore integrity issues detected.
- Mitigation of induced seismicity related to wastewater disposal may be accomplished by limiting injection rates and pressures, and locating disposal wells distal from faults.
- The effectiveness of mitigation methods for induced seismicity related to hydraulic fracturing is difficult to assess given the many operational parameters involved. Additional study is underway to assess the impact of variations in pump rate, injected fluid volumes and sand concentration on induced seismicity.
- The occurrence of induced seismicity events within the Montney is much greater in the structurally deformed Rocky Mountain foothills belt and close to the pre-existing structures of the Fort St. John Graben complex.
- Induced seismicity is more commonly observed in wells undergoing hydraulic fracturing in the lower portion of the Montney formation. Stimulations in this setting are more likely to re-activate deeper, pre-existing faults.
- Identifying and predicting geohazards that may cause induced seismicity is challenging. In many cases, reflection seismic does not resolve small scale strike slip faulting, which may be susceptible to reactivation and generation of induced seismicity events.
- Dense array data indicates most induced events in northeast B.C. occur within the completion zone or in deeper horizons.

Discussion

Underground fault movement can create seismic waves that propagate through the subsurface to the surface, resulting in ground motion. Ground acceleration values have been recorded for three events in northeast B.C. Two 2.9 M_L events in the Horn River Basin had peak acceleration values of 0.017 g (acceleration due to gravity) and 0.0166 g. A peak ground acceleration of 0.038 g and a mean ground acceleration of 0.013 g were calculated from a 3.1 M_L event recorded in the Montney.

Fault Movement

Moment magnitude, equating roughly to Richter magnitudes in northeast B.C., is a function of fault slip area, the distance the fault slipped and rock rigidity. In northeast B.C. felt events have ranged from 2.4 M_L to 4.4 M_L. Fault slippage for these events can be estimated using Figure 6. Estimated fault displacement resulting in 3.0 to 4.0 M_L induced events in northeast B.C. is in the one- to 10-centimetre range for faults one to four km long. Fault movement from lower magnitudes is measured in the millimetres.

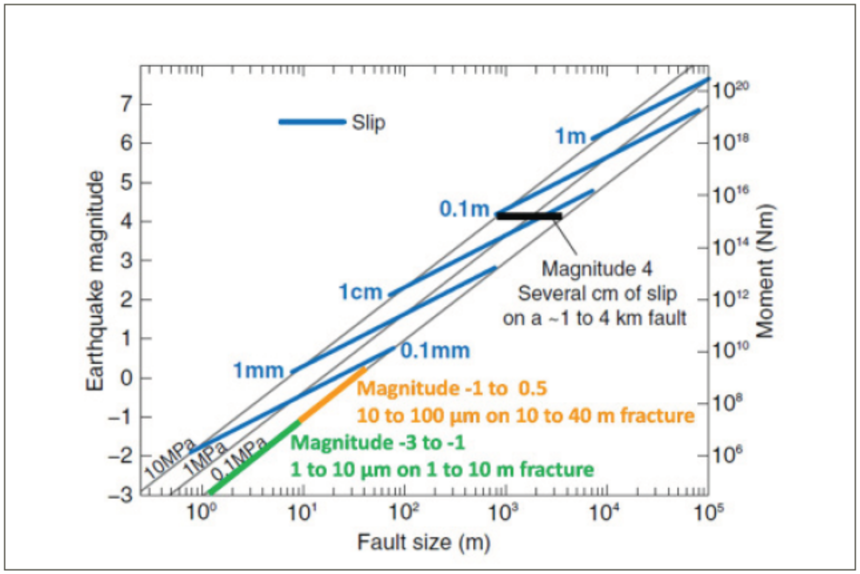


Figure 6: Fault slip for various magnitudes and fault movement areas. Refers to earthquake stress drops ranging from 0.1 to 10 MPa. (Zoback and Gorelick, 2012; modified by Maxwell, 2013)

Wellbore Integrity

The Commission has found no evidence of wellbore damage in the vertical sections of shale gas multi-laterals that can be linked to induced seismicity. The potential exists to reduce the productive flow capacity of wells by restricting access to completion stages due to casing damage in the horizontal portion of wellbores.

Shallow aquifer isolation

Hydraulic fracture completion depths in the Montney and Horn River Basin range from approximately 1,800 to 2,500 m. Maximum freshwater aquifer depths, conservatively estimated, range from 300 to 600 m, with most potable water wells in northeast B.C. occurring from 25 to 120 m. This leaves, at a minimum, 1,200 m of mixed lithology sediments as a barrier to hydraulic fracture fluid infiltration. In addition, shale gas wellbores are flowed back to initiate gas production, and a significant portion of fracture fluid is recovered in this process. Fluids and gas are continuously drawn toward the wellbore as the lowest point of pressure in the reservoir.

Felt events

There are seven induced seismicity areas in northeast B.C. where events have been felt. Generally, people close to the epicentre experience a few seconds of shaking. Shaking intensity dissipates with distance from the epicentre. No surface damage linked to induced seismicity has been reported. These felt events are III to IV (weak to light) on the Mercalli Intensity Scale (Figure 7).

In the areas of Graham, Doe-Dawson, Altares and Eagle, residents reported felt events to the Commission. In each case the Commission investigated and provided responses. At Eagle, almost 90 events, linked to waterflood injection, were recorded from March 1985 to July 2013. Horner (1994) cataloged 29 events from November 1984 to March 1993 and reported that 19 of these events were felt by Fort St. John residents. The operating company has reduced injection rates and the induced seismicity has been effectively mitigated.

At Doe-Dawson, during hydraulic fracturing operations in the Lower Montney, 16 events were recorded from Oct. 16-28, 2013. Reports of six felt events were received by the Commission from nearby residents. These felt events were Mercalli III to IV (weak to light). The Commission ordered the deployment of a dense seismograph array to monitor future hydraulic fracturing operations in the area. In October 2014 fracturing operations resumed two km to the southeast. The new fracturing operations triggered only a few minor events in the Upper Montney, but higher magnitude and felt events began occurring with hydraulic fracturing in the Lower Montney. Active faults were delineated on the dense array seismicity plots. The Commission is working with the operator on mitigation options.

Instrumental Intensity	Acceleration (g)	Velocity (cm/s)	Perceived Shaking	Potential Damage
I	< 0.0017	< 0.1	Not felt	None
II-III	0.0017 - 0.014	0.1 - 1.1	Weak	None
IV	0.014 - 0.039	1.1 - 3.4	Light	None
V	0.039 - 0.092	3.4 - 8.1	Moderate	Very light
VI	0.092 - 0.18	8.1 - 16	Strong	Light
VII	0.18 - 0.34	16 - 31	Very strong	Moderate
VIII	0.34 - 0.65	31 - 60	Severe	Moderate to heavy
IX	0.65 - 1.24	60 - 116	Violent	Heavy
X+	> 1.24	> 116	Extreme	Very heavy

Figure 7 – Mercalli intensity scale with ground accelerations. (Modified from the USGS Instrumental Intensity Scale.)

Induced Seismicity Permit Conditions

1. During fracturing operations on this well, the operator shall immediately report to the Commission Emergency Contact 1-800-663-3456 any seismic event
    a. recorded by the operator or any source available to the operator as being magnitude 4.0 or greater and within a 3 km radius of the drilling pad, or
    b. felt on the surface within a 3 km radius of the drilling pad.
2. In the event that a pad is identified, either by the operator or the Commission, as being responsible for the seismic event described in section 1(a) above, the operator, subject to section 3 below, will suspend fracturing operations on this well immediately.
3. Fracturing operations at this well, suspended under section 2 above, may continue if:
    a. the operator presents to the Commission a plan for mitigation aimed at reducing the seismicity or eliminating well operations related to the induced seismicity,
    b. the Commission is satisfied with this plan, and
    c. the operator implements this plan.

Analysis of Mitigation Options

In B.C., the Commission has responded to induced seismicity by improving the regional CNSN array to better locate new induced seismic event clusters; deploying dense arrays to obtain precise depths and locations for a wide range of event magnitudes; implementing new well permit conditions requiring the reporting of felt events, and the suspension of operations triggering a 4.0 M_L event or greater. Following in this section is an analysis of other mitigation options currently being implemented and/or studied by the Commission.

Several other jurisdictions have developed, or are developing, procedures to address induced seismicity. For example, Colorado employs a traffic-light system based on the Modified Mercalli Scale whereby companies are required to modify operations if triggered events are felt at surface, and suspend operations in the event of a 4.5 M_L event. Ohio has responded by establishing buffer zones around higher risk areas, and operators are required to have a seismicity mitigation plan in place and monitor hydraulic fracture operations inside the buffer zone. The monitoring must have resolution down to at least 1.0 M_L, and if a 1.0 M_L event is detected the company meets with the Ohio Conservation Commission to discuss a plan to resume operations. The Canadian Association of Petroleum Producers has an induced seismicity operating practice that has recommendations for assessing seismicity potential, drilling design and responding to induced seismicity (http://www.capp.ca/canadaIndustry/naturalGas/ShaleGas/Documents/natural-gas-operating-practice-7.pdf).

Wastewater disposal well induced seismicity mitigation steps

The Commission responded to wastewater disposal well induced seismicity by working with the well owner in increasing seismic monitoring and decreasing injection rates. Disposal well approvals contain specific conditions for well operation, monitoring, testing and reporting to ensure the geologic containment of fluids, including:

- Maximum injection and ultimate reservoir pressure limits.
- Continuous monitoring and recording of tubing and casing pressure.
- Reporting monthly disposal volume, pressure and operating hours.
- Annual reservoir pressure and packer isolation testing.
- Periodic wellbore integrity and zonal isolation logging.

Applications to the Commission for wastewater disposal in zones near pre-existing faults or in areas with known induced seismicity may be denied.

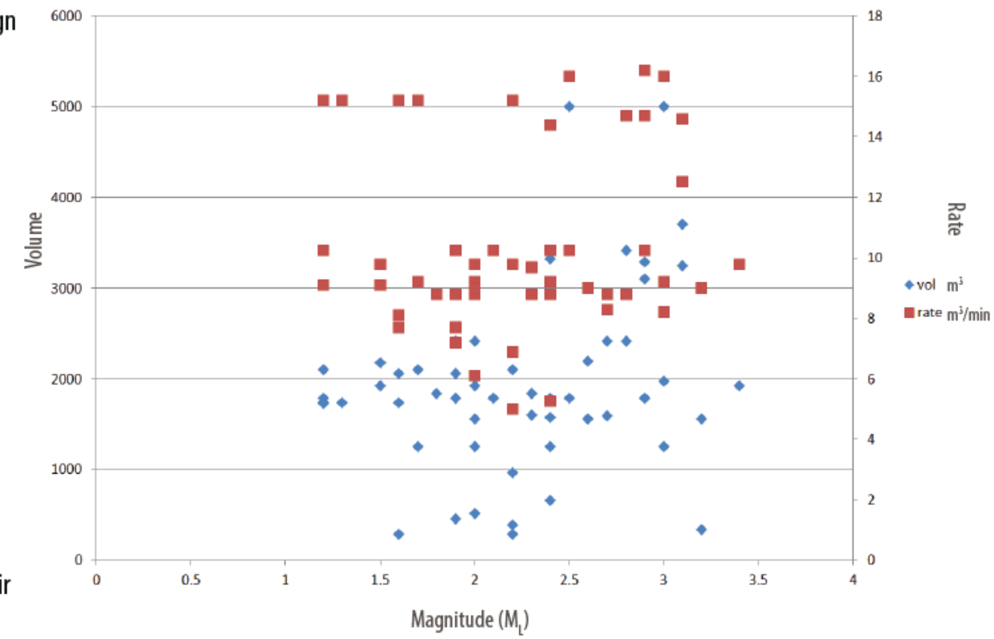


Figure 8 – Comparison of magnitude to causal hydraulic fracturing stage pump rate and volume.

Hydraulic fracturing induced seismicity mitigation steps

In northeast B.C., operators have tried several methods to prevent or mitigate hydraulic fracturing induced seismicity, including reducing hydraulic fracture stage volumes, reducing pump rates, reducing proppant concentration, skipping hydraulic fracture stages and flowing back fracture fluids. The success of these mitigation procedures is difficult to ascertain given the many hydraulic fracture operational parameters at play and the anecdotal nature of the results. High-resolution dense array deployments have proven useful for detecting very low magnitude events and the early fault identification needed to initiate mitigation.

Fault Delineation and Dense Seismograph Arrays

A key to induced seismicity mitigation is early active fault identification. This may be achieved by real-time dense array monitoring or real-time microseismic monitoring. In both the Horn River Basin and the Montney, many of the active faults are strike-slip and difficult to detect with reflection seismic. Snelling (2013) demonstrates that the location and orientation of active faults may be resolved with microseismic monitoring. In some dense array submissions to the Commission, the active fault type along with the strike, rake and dip were obtained using dense arrays. Often individual seismic events could be linked to separate hydraulic fracturing stages.

Reductions of Injected Volumes and Pump Rates

Several attempts have been made to mitigate the seismicity through reducing volumes and/or pump rates, but results are inconclusive. In the Horn River Basin, the operator at the d-1-D pad reduced pump rates from 16 m^3/min to 13 m^3/min and reported a slight reduction in event frequency. At Kiwigana in the Horn River Basin the operator pumped at a consistent 13 m^3/min, and while events were triggered at reactivation zones, magnitudes did not exceed 1.9 M_L.

Event magnitudes are correlated to the volume and pump rate for the fracture stage considered to have triggered the event (Figure 8). No clear correlation is apparent between pump rate or volume and magnitude. The magnitudes on the x-axis are the events triggered by the overlying volume and rate. For example, Magnitude 3.0 events can be seen to have been triggered by pump rates of eight to 16 m^3/min with corresponding volumes of 1,100 to 5,000 m^3.

In Caribou and Beg-Town, the operator reduced pump rates and volumes in an effort to mitigate induced events. In some cases it appeared frequency and magnitude of induced events were reduced. The success of these measures is anecdotal. No dense array was deployed to monitor fault reactivation.

Operators are testing different rates and volumes to mitigate induced events along active faults closely delineated with dense arrays.

Flowback

Flowback occurs when the hydraulically fractured zones are opened up to production. Fluid and gas flow to surface, reducing the elevated formation pore pressure needed to trigger fault movement. Flowback appears to be effective in reducing seismicity. In one northeast B.C. case, following multiple events along a wellbore and a felt 2.7 M_L event, hydraulic fracturing operations were suspended and the wellbore was flowed back. No additional events occurred after flowback.

Stage Skipping

Two operators reported skipping completion stages near fault reactivation zones in an effort to reduce the magnitude and frequency of induced events. This effort is also inconclusive. In some cases no additional events occurred, while at other times after skipping a stage, new events occurred. In one recent case, dense array results (Figure 9) showed events were being triggered at almost every stage along a wellbore and up to 350 m from where the wellbore intersected the active fault.

In the Horn River Basin, fault re-activation zones are well defined. It appeared injection had to be very close or within the fault reactivation zone for fault reactivation to occur. Dense array evidence in the Montney suggests events can be triggered from outside the reactivation zone, perhaps up to 200 to 300 m away from the fault with fluid pressure being transmitted through fracture networks. There is also dense array evidence that fault movement may occur several hundred metres below the Montney completion zone.

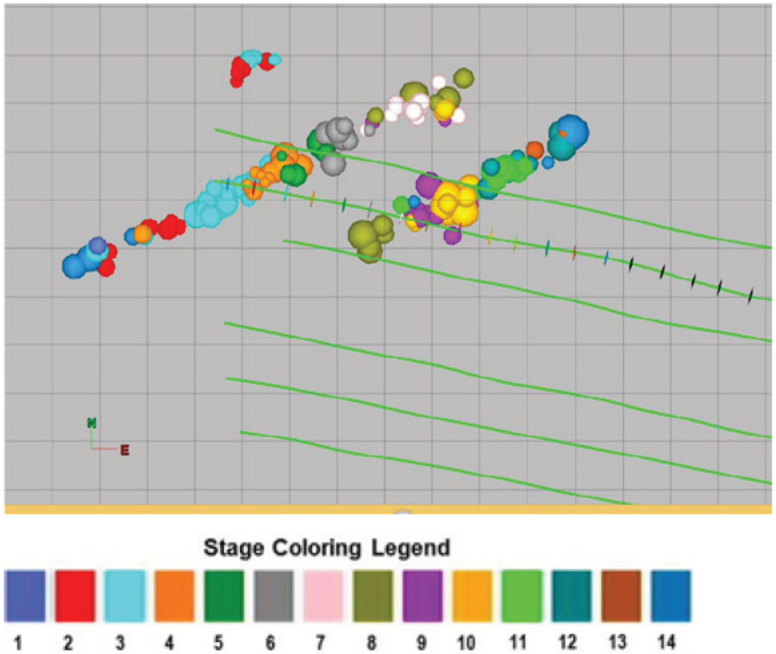


Figure 9: Event locations delineating faults and stage that triggered fault movement. Events sized by Mw and coloured by stage. Magnitudes range from 1.1 to 3.2 Mw. (Grid 100 m by 100 m.)

Recommendations

1. Increase regulatory scrutiny for disposal wells

The vast majority of wastewater disposal wells in northeast B.C. do not generate induced seismic events. Induced seismic events have been noted at two disposal wells, occurring in marginal reservoir quality rock in proximity to existing faults.

ACTION: Evaluation of wastewater disposal well applications will incorporate a geological and geophysical analysis to identify pre-existing faults near the proposed site. Approval conditions may include seismic monitoring to detect and accurately locate seismic events and previously unrecognized fault reactivation zones.

2. Encourage deployment of high-resolution dense arrays

The improved CNSN grid has significantly improved the Commission's ability to monitor for induced seismicity in northeast B.C. However, the improved CNSN epicenter resolution varies with location and is inadequate to confidently locate events. Event depths cannot be resolved with the CNSN. Current dense array deployments by operators, either ordered or voluntary, provide precise locations and depths and, at times, the active fault delineation needed to implement mitigation procedures.

ACTION: The Commission will continue to monitor events recorded by the CNSN to locate induced seismicity areas. Dense array deployments will be requested in areas where more detailed information is required, including areas with felt events, higher magnitude clusters and high-frequency clusters.

3. Continue to improve regulations to address induced seismicity

Currently, the Commission employs well permit conditions to regulate induced seismicity. Permit conditions were initially used in the Horn River Basin to address concerns in what was believed to be a geographically confined area of induced seismicity. The recognition of induced seismicity related to wastewater disposal and hydraulic fracturing within the Montney indicates a more uniform application of regulations is appropriate.

ACTION: The current permit conditions used by the Commission to respond to induced seismicity will be placed in regulation.

4. Increase public availability of data necessary to study induced seismicity

Dense array data provides precise induced event locations and depths as well as the detailed seismological data required for research into induced seismicity. The Commission currently supports research projects at UBC and NRCan and has requested support from industry for several international research projects.

ACTION: The Commission will continue to promote and support the sharing of dense array data with researchers and the publication of research results. In addition, the Commission will promote awareness of the extensive hydraulic fracturing operational database it maintains and is available to the public.

5. Assess the use of hydraulic fracturing buffer zones to protect sensitive infrastructure and subsurface projects

In addition to increased seismicity monitoring, it may be prudent in some circumstances to implement buffer zones near subsurface disposal or storage facilities.

ACTION: The Commission will identify disposal and storage projects that could be adversely affected by fault reactivation and investigate whether conditions on hydraulic fracturing in these project areas or zones is appropriate.

Conclusion

The Horn River Basin report recommendations resulted in an increased emphasis on the detection of potential geohazards, enhanced seismicity monitoring and implementation of effective notification and consultation procedures. In collaboration with the University of British Columbia (UBC), NRCan, Geoscience BC and industry partners, the Commission has studied geomechanical and operational controls on induced seismicity in order to develop and optimize detection, monitoring and mitigation strategies.

The Commission has been proactive in dealing with induced seismicity and has taken numerous steps since 2012 to improve understanding, monitoring and mitigation. Induced seismicity related to hydraulic fracturing has now been detected in northeast B.C.'s Horn River Basin and Montney. It has also occurred at two sub-Montney wastewater disposal sites.

Regional and detailed monitoring of seismic events in northeast B.C. indicate "felt" induced seismicity is uncommon. Of the approximately 7,500 hydraulic fracture stages performed during the August 2013 to October 2014 investigation period, only 11 triggered events felt at the surface. None of the events resulted in damage to surface structures, and only minor horizontal wellbore effects have been noted. The investigation found no loss of wellbore containment.

The mechanism for inducing seismic events is the reactivation of faults via the injection of fluids either from short term, high-pressure hydraulic fracturing or longer term, higher cumulative volume wastewater disposal. Mitigation of wastewater disposal induced seismic events may be accomplished by reducing injection rates, limiting the increase in reservoir pressure and locating distal from faults. Mitigation of induced seismicity related to hydraulic fracturing is more difficult to assess given the many operational parameters involved, but the Commission has identified fault zone avoidance and early flow-back of fracture fluids are probably the best mitigation techniques.

Dense array data is critical to understanding induced seismicity. Recent deployments have precisely delineated active faults and provided detailed structural and seismological data that can be applied to risk assessment and mitigation of induced seismicity.

A comprehensive regulatory framework is in place ensuring continued responsible development of unconventional resources in B.C. The Commission has also formed research partnerships with NRCan, UBC and Geoscience BC to study the effects and relationships between seismicity and hydraulic fracturing and water disposal.

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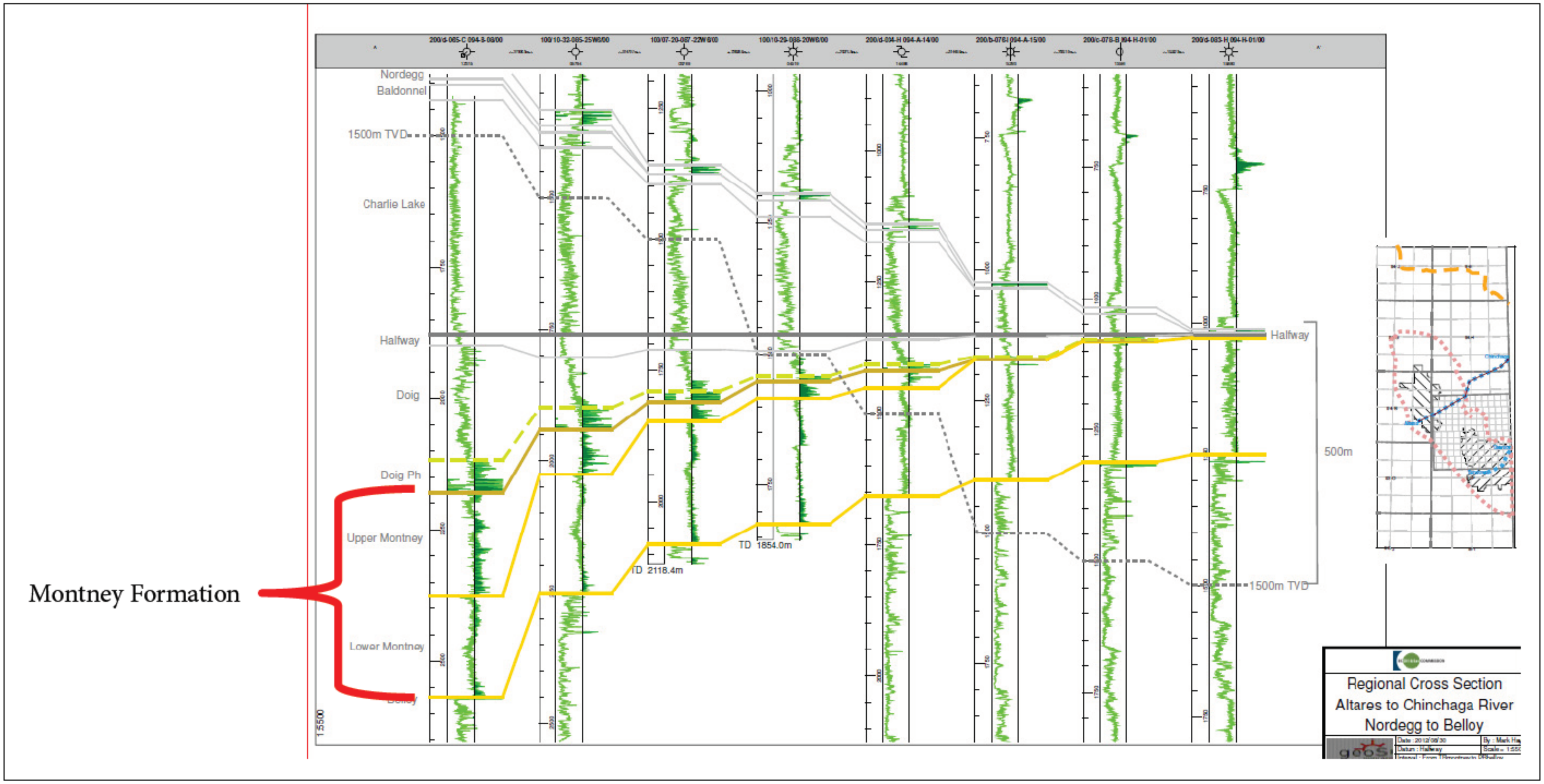
Appendix 1

Montney Cross-Section (Altares to Chinchaga River)



Appendix 2

Investigation of Observed Seismicity in the Horn River Basin

In 2012 the Commission released the report Investigation of Observed Seismicity in the Horn River Basin. The investigation concluded that seismic events observed within remote and isolated areas of the Horn River Basin in northeast B.C. between 2009 and 2011 were caused by fluid injection during hydraulic fracturing in proximity to pre-existing faults. As a result, the Commission made seven recommendations to enhance seismic monitoring, industry best practices and regulations. In the past two years, significant progress was made in implementing the recommendations, as detailed below.

1 Improve the accuracy of the CNSN in northeast B.C.

Six new seismograph stations, funded by the Canadian Association of Petroleum Producers (CAPP) and Geoscience BC, were installed and connected to the CNSN in August 2013. An additional two stations (funded by NRCan and the Commission) were brought online in 2014 (Figure 12). These additions have significantly improved CNSN resolution. Before the improvements, epicentre resolution uncertainty was five to 10 km. Current epicentre resolution varies from one to five km depending on event location. A comparison of same-event epicentres recorded by dense arrays and the CNSN show many CNSN located events are within three km of dense array epicentres.

2 Perform geological and seismic assessments to identify pre-existing faulting

Since 2012, most of the high-volume hydraulic fracturing and almost all of the new CNSN-recorded seismicity has occurred within the Montney. Operators commonly use 3D seismic to interpret geological structures and are developing a good understanding of structural trends and fault orientations.

3 Establish induced seismicity monitoring and reporting procedures and requirements

Seismic monitoring and reporting have been addressed in three ways. First, a notification and consultation procedure was implemented to facilitate communication between operators and the Commission, to improve seismic monitoring and explore possible mitigation options. Second, the Commission has ordered the deployment of dense seismograph arrays in three separate locales to collect detailed seismological data on probable induced event clusters. Third, well permit conditions are in place for all of northeast B.C. requiring operators to immediately report events within three km of their operations that

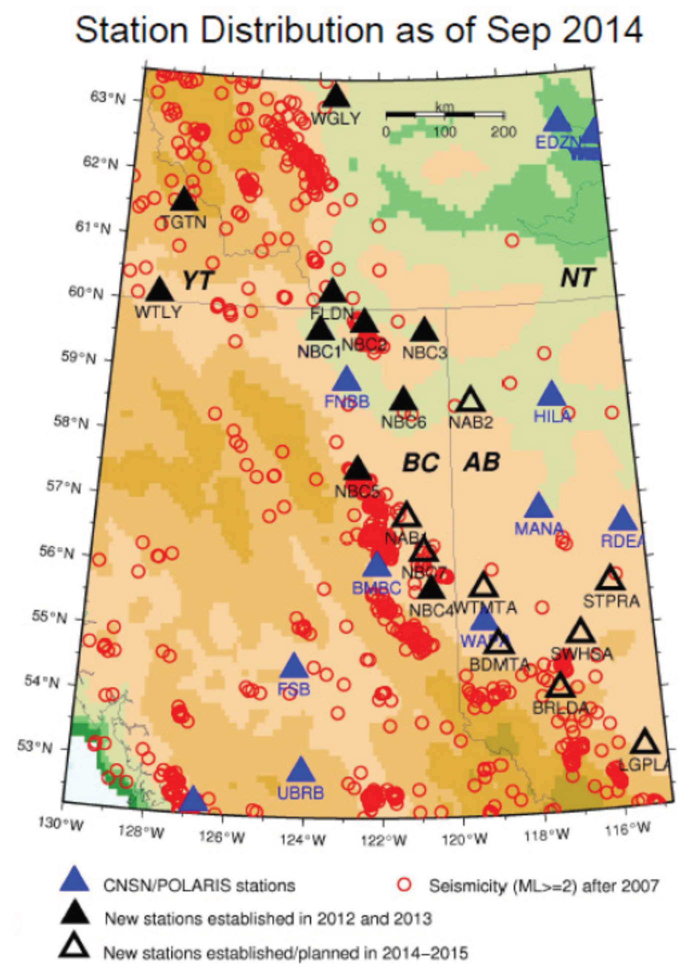


Figure 12: Locations of CNSN stations in northeast B.C., new stations (blue triangles)

are felt or are equal to or exceed 4.0 ML. Permit conditions require the suspension of operations on the wellbore linked to any 4.0 ML event. Operations can be resumed with a Commission-approved mitigation plan.

4 Station ground motion sensors near selected northeast B.C. communities to quantify risk from ground motion.

One strong motion detector was installed in Fort St. John. In addition, dense arrays were deployed or will be in place to monitor future operations within the Montney. Velocities from these near surface seismographs can be used to calculate ground motion at the station location.

5 The Commission will study the deployment of a portable dense seismograph array to selected locations where induced seismicity is anticipated or has occurred.

The Commission studied and identified a portable dense array option; however, the combination of ordered seismicity monitoring and voluntary deployment has provided the data necessary to understand the clusters of events detected by the CNSN.

6 Require the submission of microseismic reports to monitor hydraulic fracturing for containment of micro-fracturing and to identify existing faults.

The requirement for mandatory submission of microseismic reports is currently under review. It is recognized microseismic monitoring is a key technology in understanding the propagation of hydraulic fractures and induced seismicity. Making a subset of that information more widely available is desirable to facilitate academic study and increase dissemination of this data.

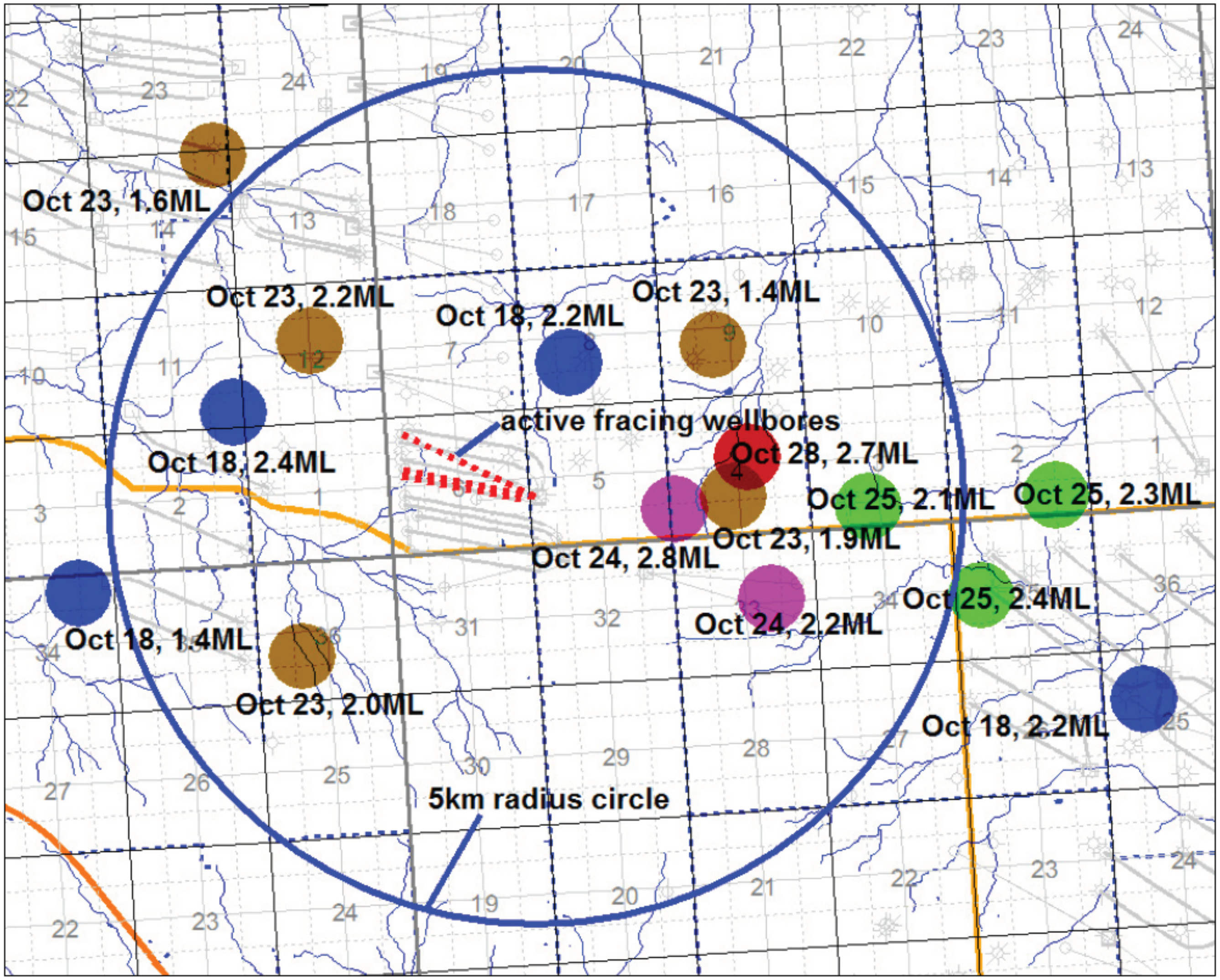
7 Study the relationship between hydraulic fracturing parameters and seismicity.

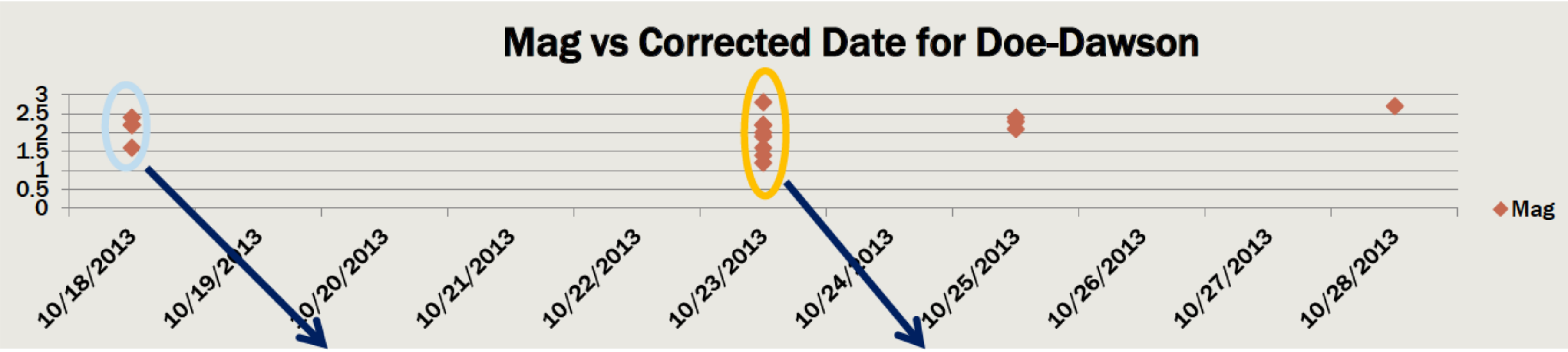
Research projects investigating injected volume and magnitude relationships are ongoing at UBC and NRCan. Several operators have experimented with hydraulic fracturing parameters to mitigate detected seismicity. No clear relationship has been found between event magnitude or frequency and pump rate, injected volume, proppant concentration or fracture stage omission. Induced seismicity associated with wastewater disposal wells shows a relationship between injection rate and event frequency.

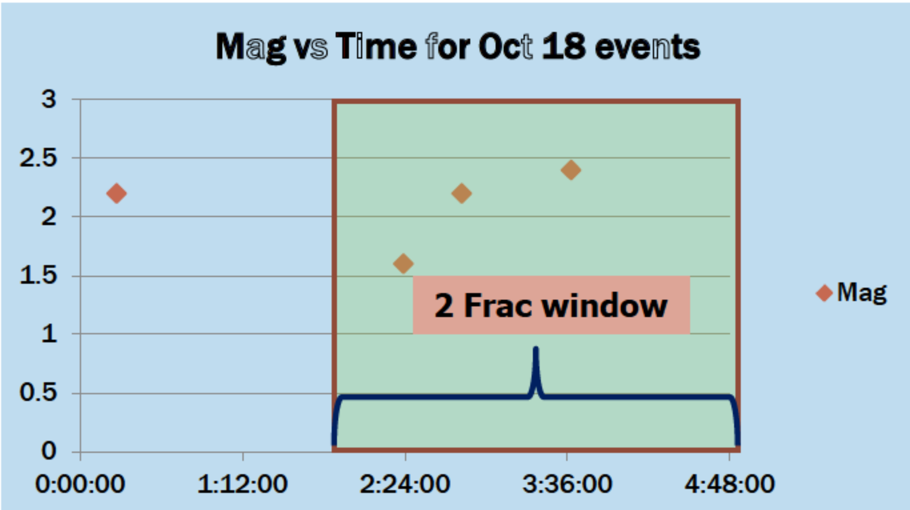
Appendix 3
Cluster Maps and Magnitude/Time Graphs

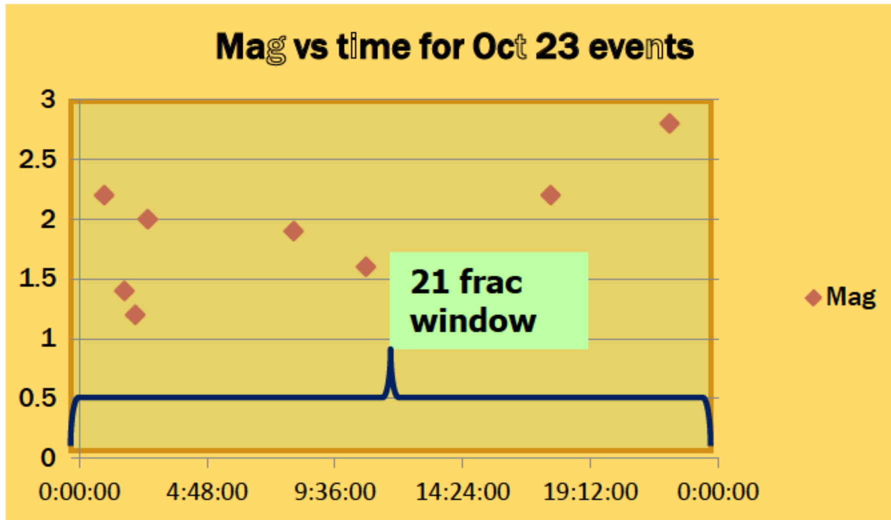
The following maps show examples of individual seismic event clusters by location (from Figure 3), and the charts show hydraulic fracturing timelines highlighted over magnitude versus time graphs. Coloured dots indicate NRCan recorded events.

1. Doe-Dawson – Oct. 18-28 cluster (NRCan recorded events)





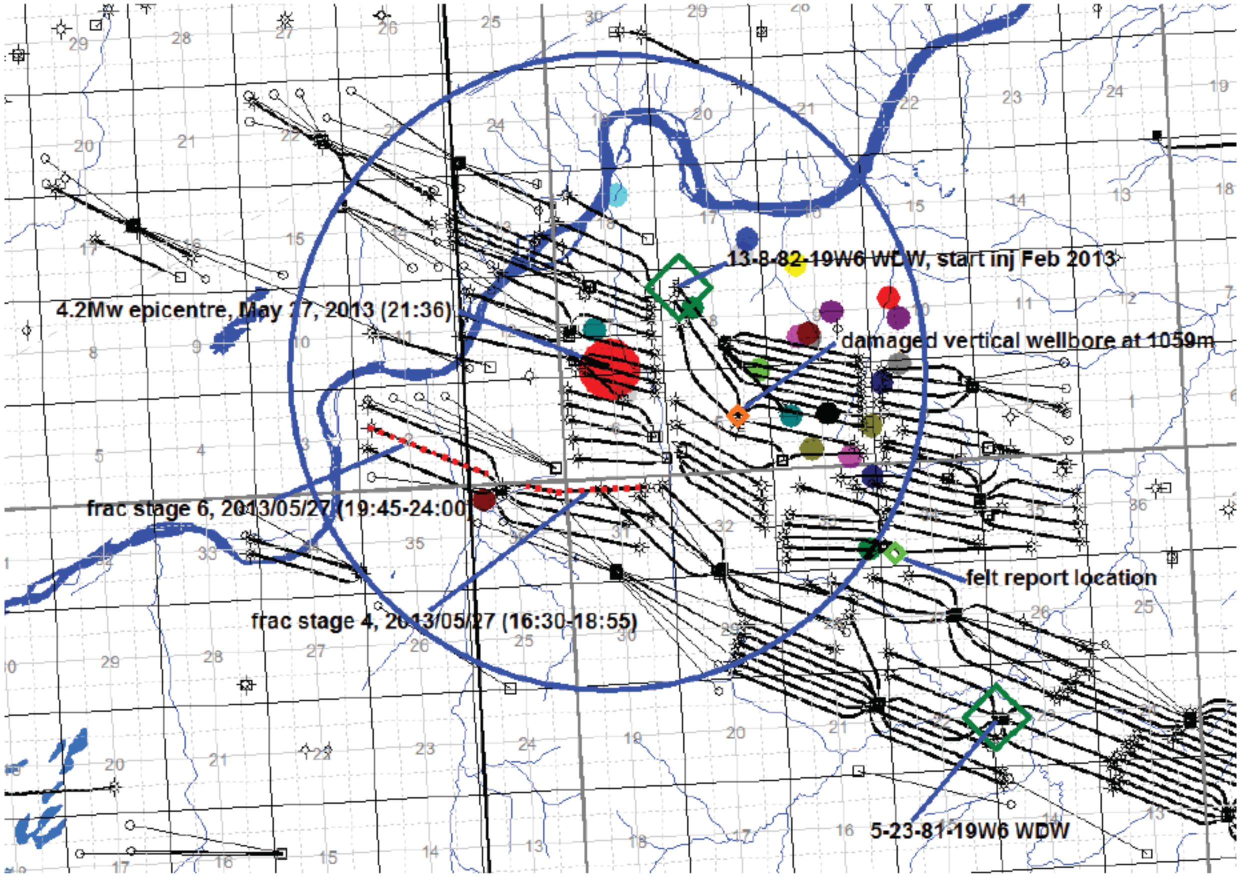


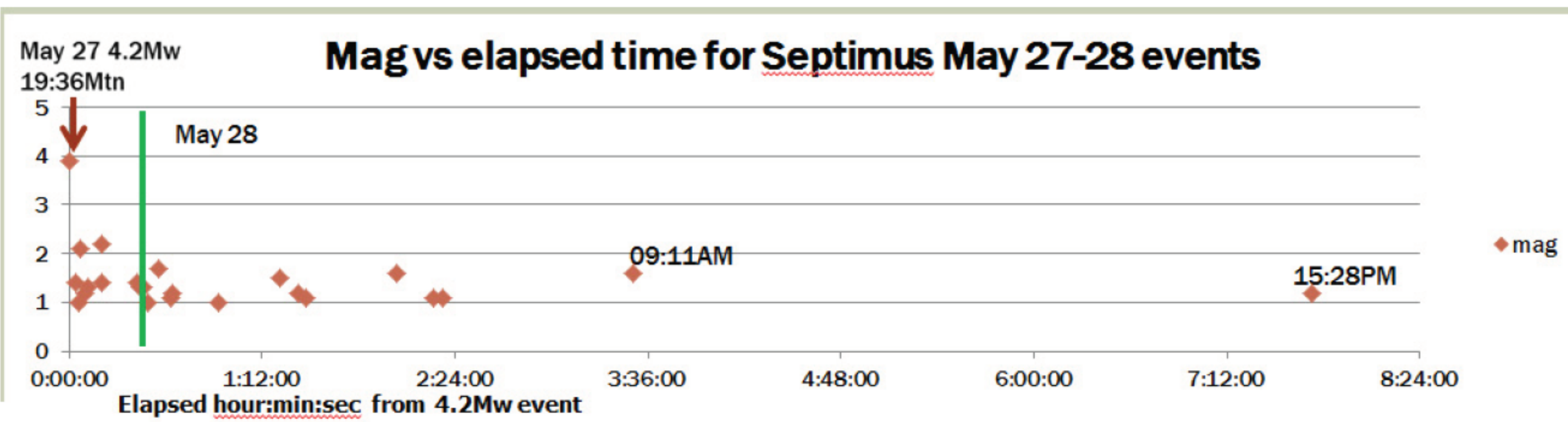


- 2 fracs prior to Oct 17 events, start 21:20 & 23:45; 2 fracs Oct 18, start 02:00 and 4:15.
- Avg frac duration 2hrs
- Avg Rate 5.0 m3/min
- Max Press 61.1 MPa
- Vol 144m3 to 662m3

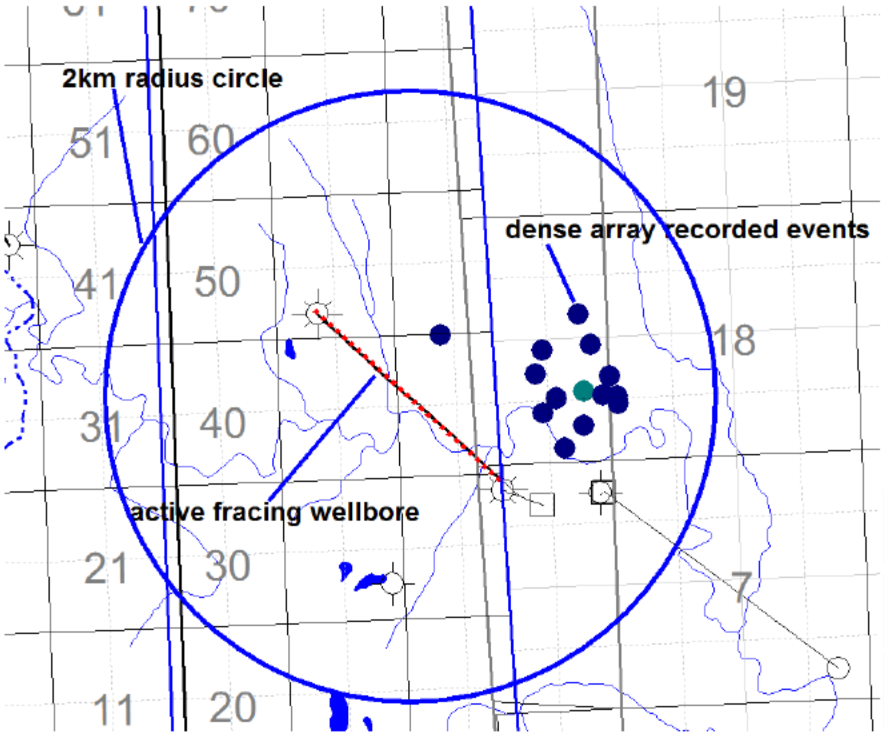
- 21 fracs start 23:15, Oct 22 to 22:50 Oct 23 in two wellbores
- Avg frac duration 45 min
- Rates vary from 6.6m3/min to 10.5 m3/min
- Max Press 64MPa
- Vol 244m3 to 524m3

2. Septimus Field – May 27-28, 2013 cluster (All events shown recorded by dense array on May 27-28, 2013)





3. Altares – Nov. 5-6, 2013 cluster

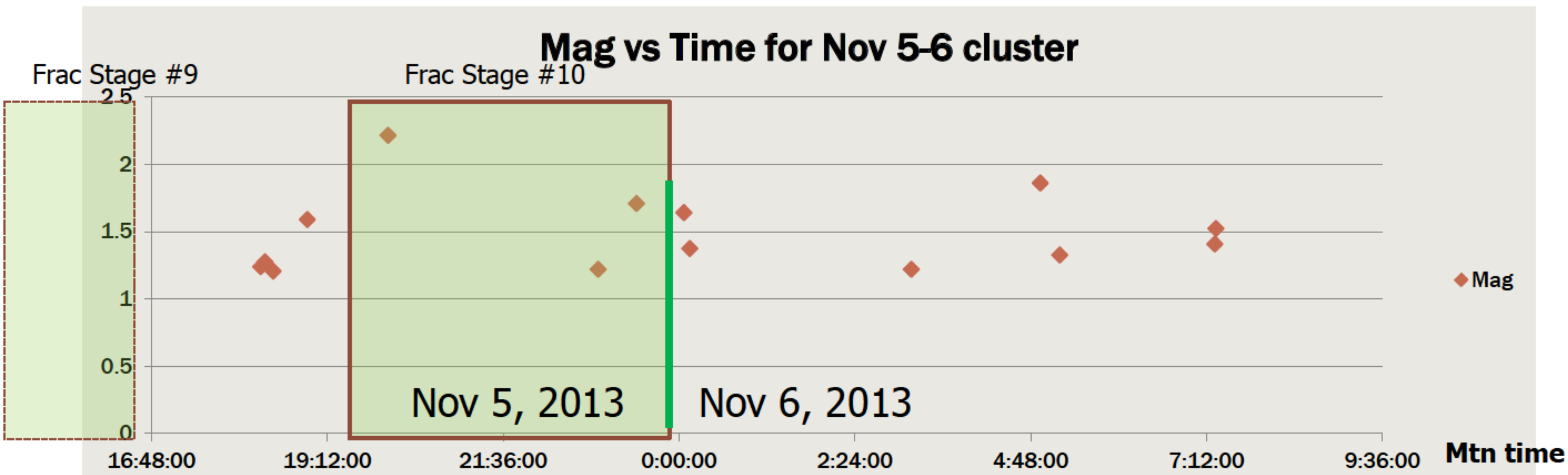


Altares, Nov 5-6 cluster

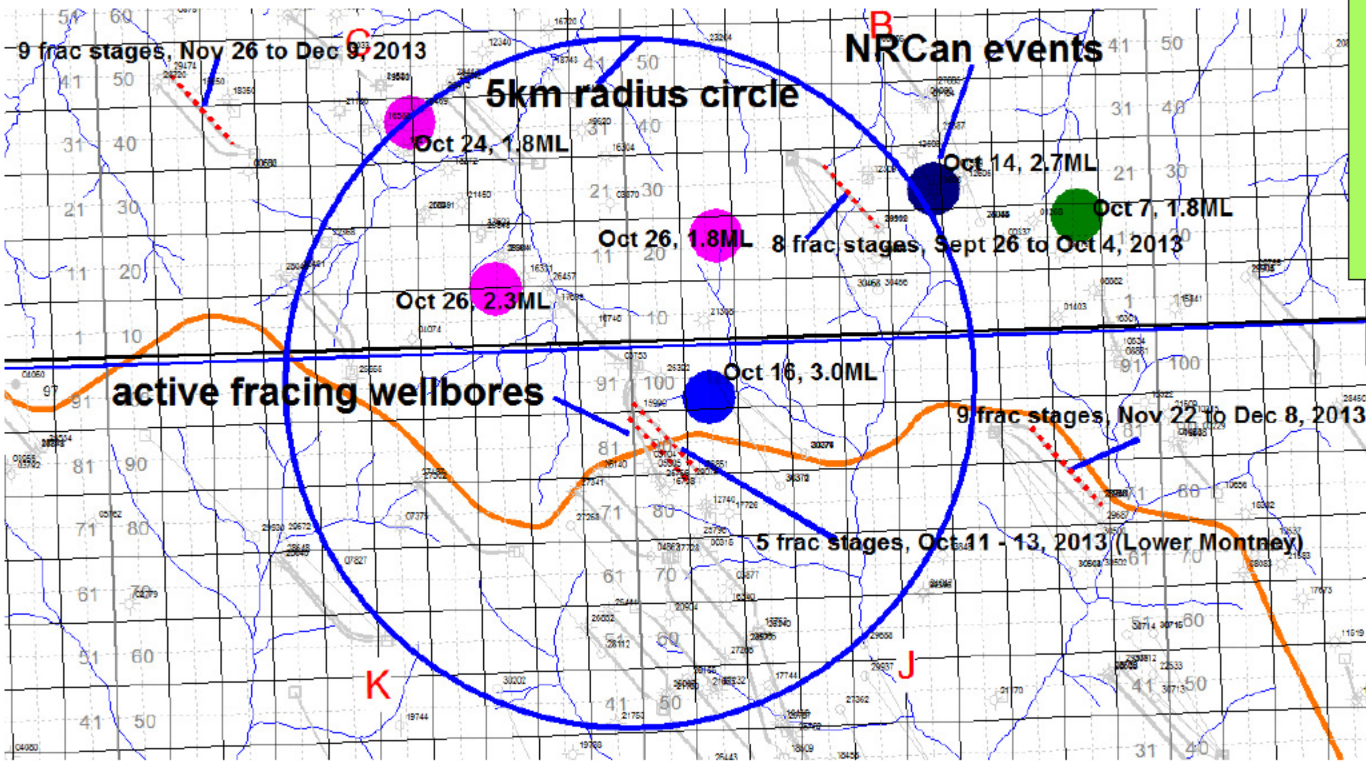
14 events, Mag 1.2 to 2.2ML over 13 hours. Recorded by dense array

- Three fracs before and during some events
- Avg brkdwn 57MPa
- Avg rate 15.1m3/min
- Avg vol 1880m3

Frac Stage #8	08:02-10:52 (mtn), Nov 5, 2013	14 events on Nov 5-6 (mtn) inside blue circle
Frac Stage #9	13:35-16:18(mtn) , Nov 5, 2013	1st event 18:17 (mtn), Nov 5
Frac Stage #10	19:35-23:30(mtn) , Nov 5, 2013	Last event, 07:20 (mtn) , Nov 6

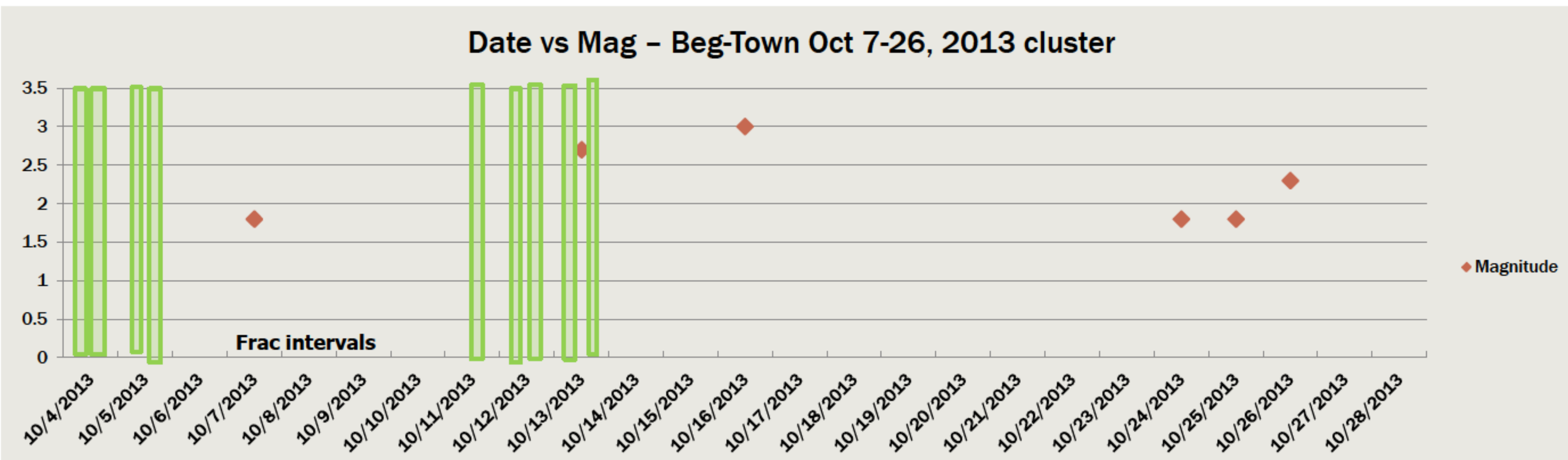


4. Beg-Town – Oct. 7-26, 2013 cluster

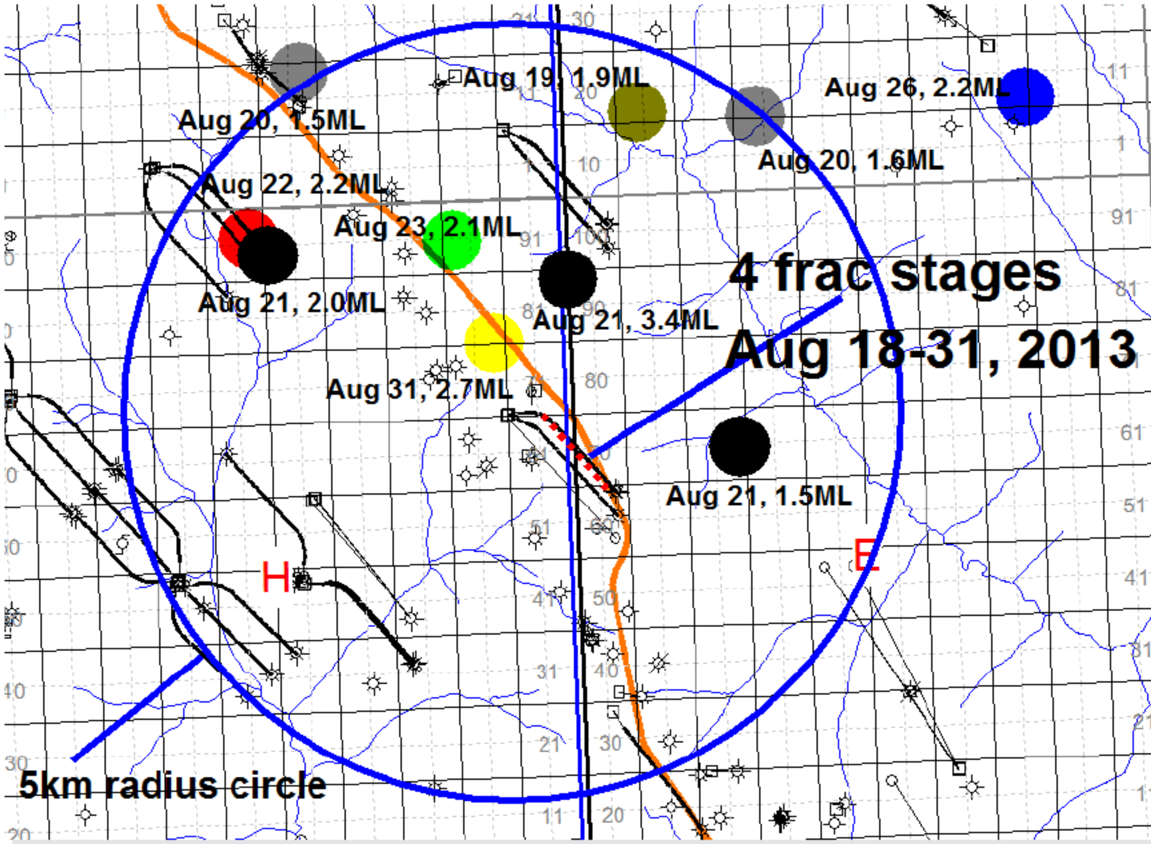


Beg-Town, Oct 7-26 cluster

- 6 NRCan recorded events, Mag 1.8 to 3.0ML over 20 days



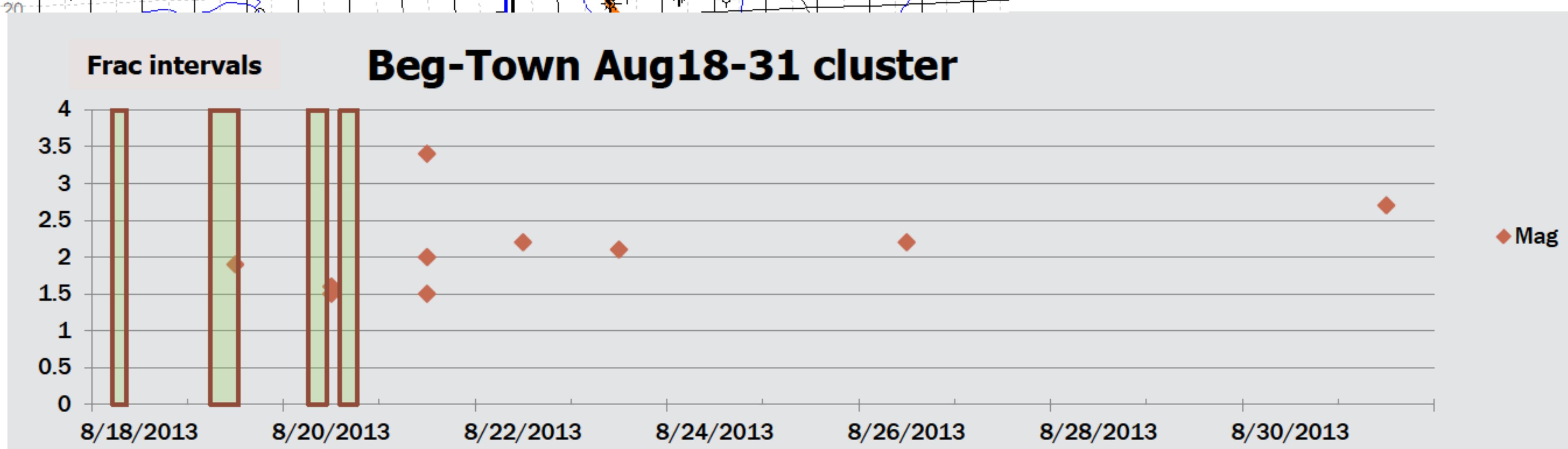
5. Beg-Town – Aug. 18-31, 2013 cluster



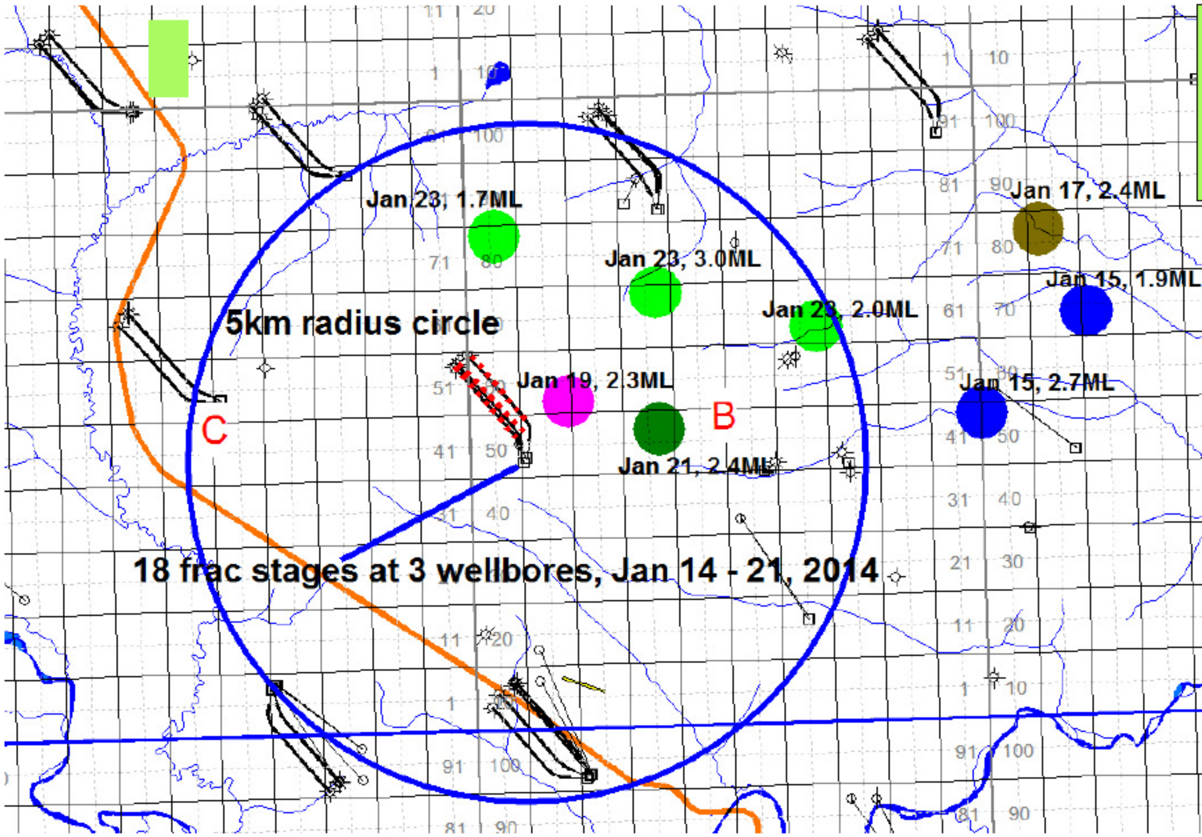
NRCan recorded events

Lower Montney fracs

- Aug 18, frac #7
  - •Start 07:00, end 08:45
  - •Brkdwn 60.1MPa
  - •Avg rate 6.9m3/min
  - •Vol 444.2m3
- Aug 19, frac #7, second attempt
  - •Start 07:30, End 13:15
  - •Brkdwon 50.7MPa
  - •Avg rate 7.7m3/min
  - •Vol 2059m3
- Aug 20, frac #8
  - •Start 07:45, end 11:30
  - •Brkdwn 59MPa
  - •Avg rate 9.1m3/min
  - •Vol 2178m3
- Aug 20, frac #9
  - •Start 15:30, end 18:30
  - •Brkdwn 54MPa
  - •Avg rate 9.8m3/min
  - •Vol 1920m3

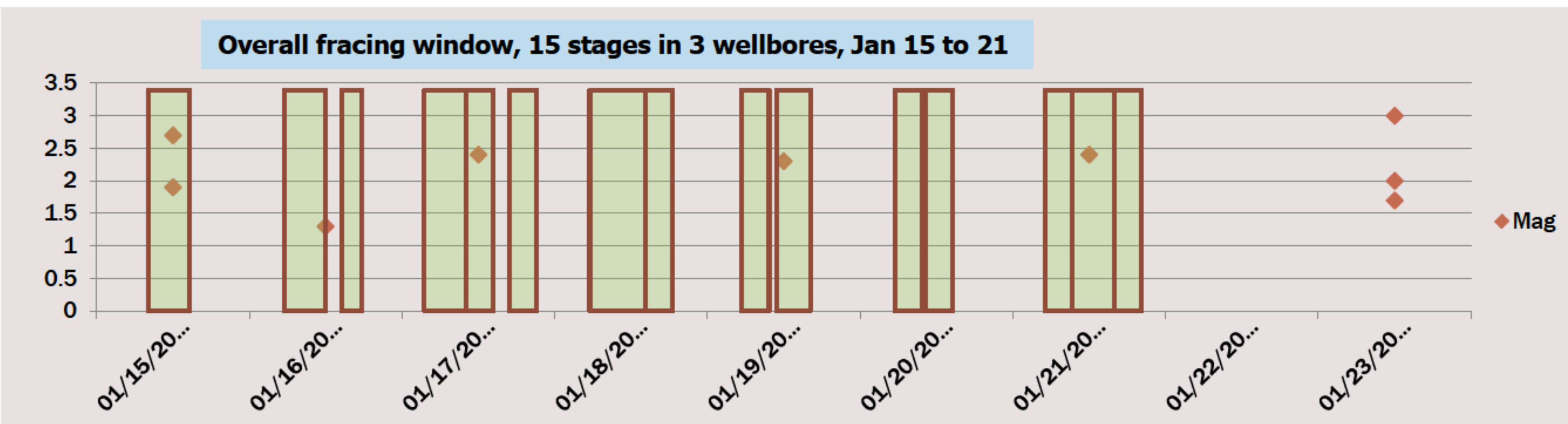


6. Caribou – January 15-23, 2014 cluster

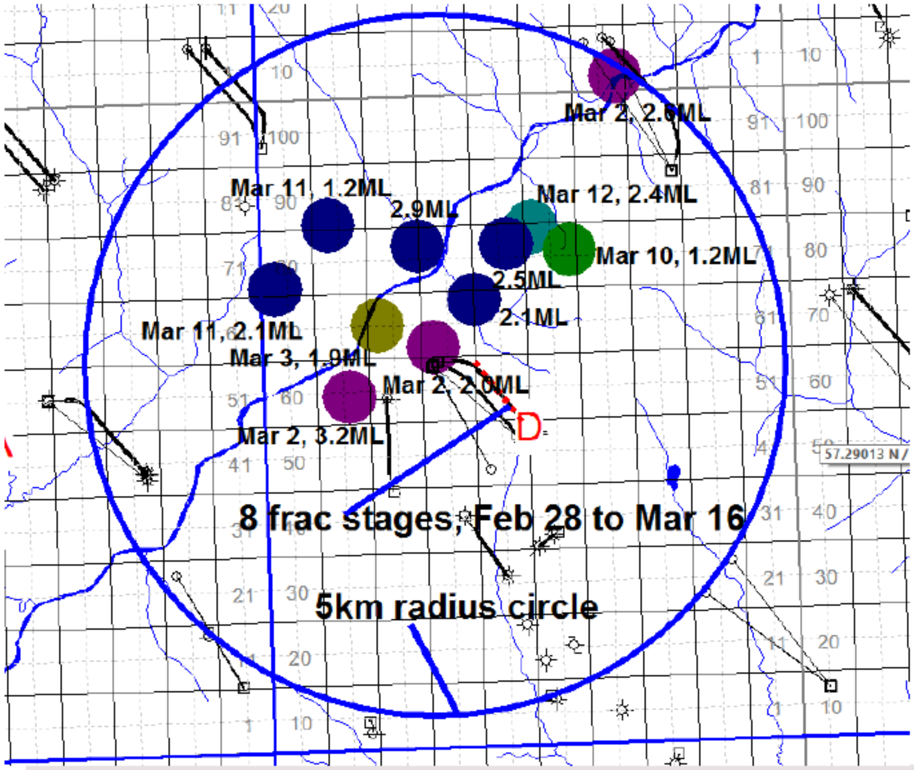


Caribou, Jan 15-23, 2014 Cluster, 9 NRCan recorded events, Mag 1.3 to 3.0ML over 9 days

- at least one event felt in camp

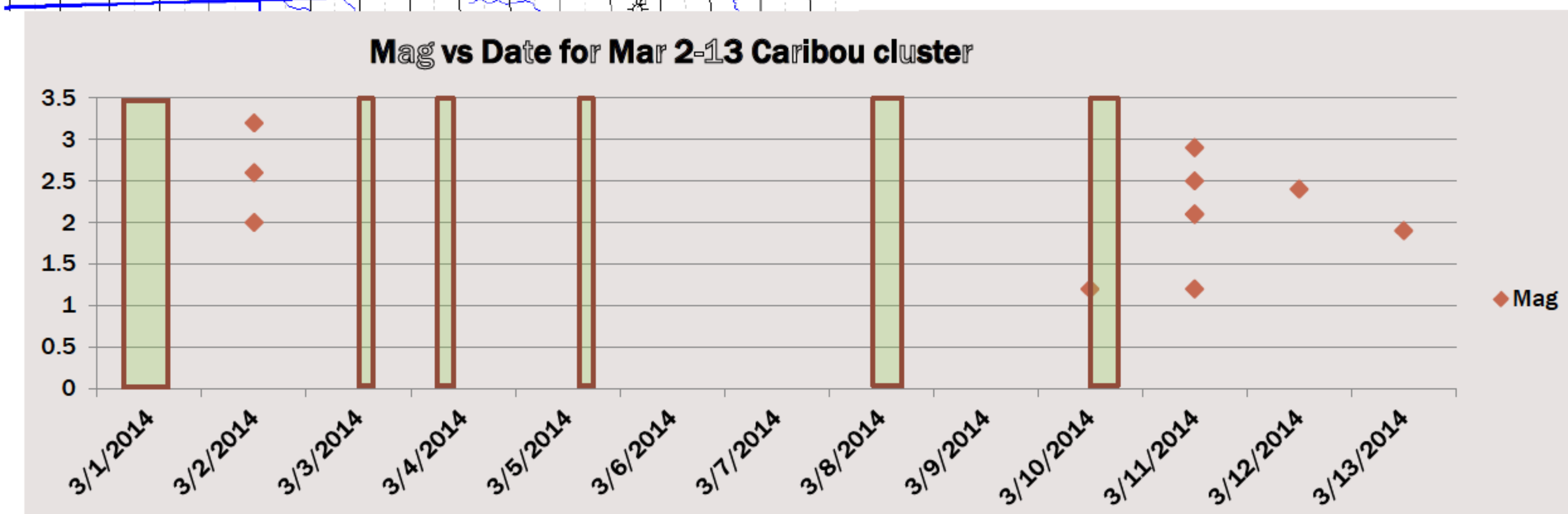


7. Caribou – March 2-13, 2014 cluster

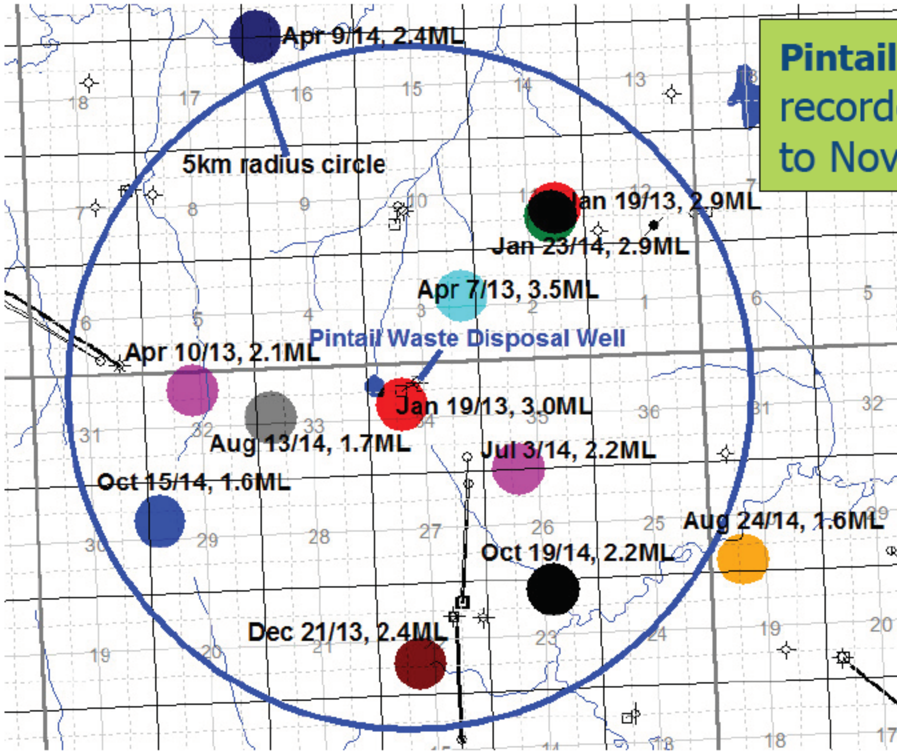


Caribou, Mar 2-13, 2014 Cluster, 11 events, Mag 1.2 to 3.2ML over 11 days

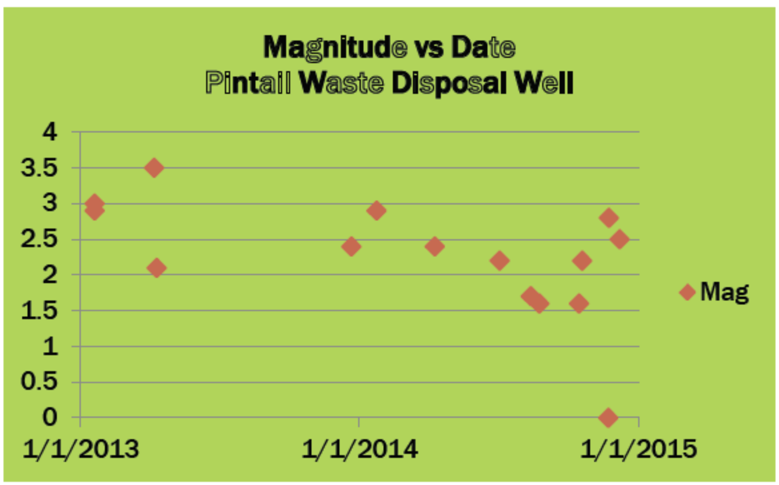
- One event felt in camp
- NRCan recorded events

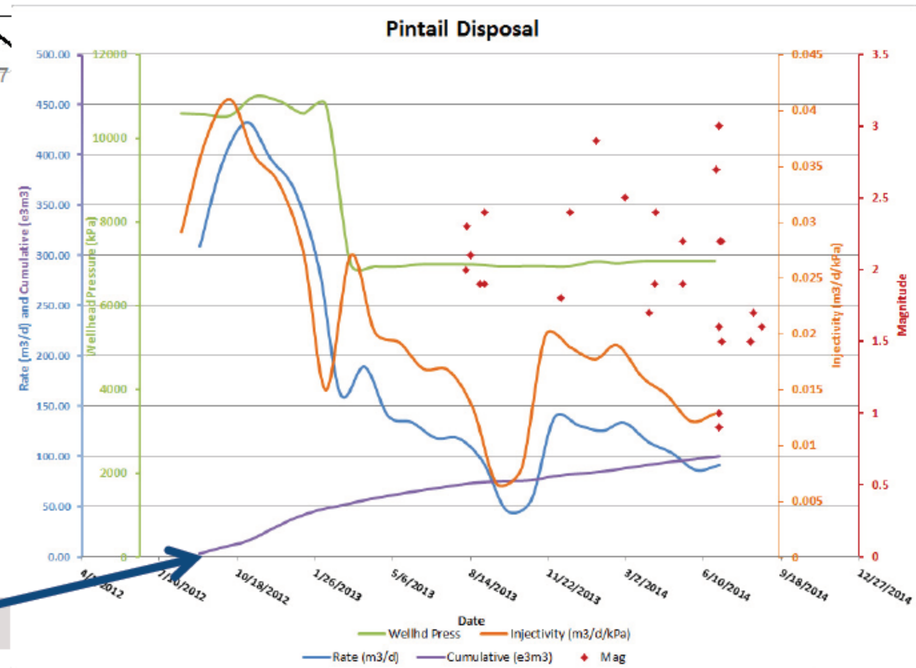


8. Pintail – Jan. 9, 2013-Nov. 1, 2014 (Wastewater Disposal Induced Seismicity)



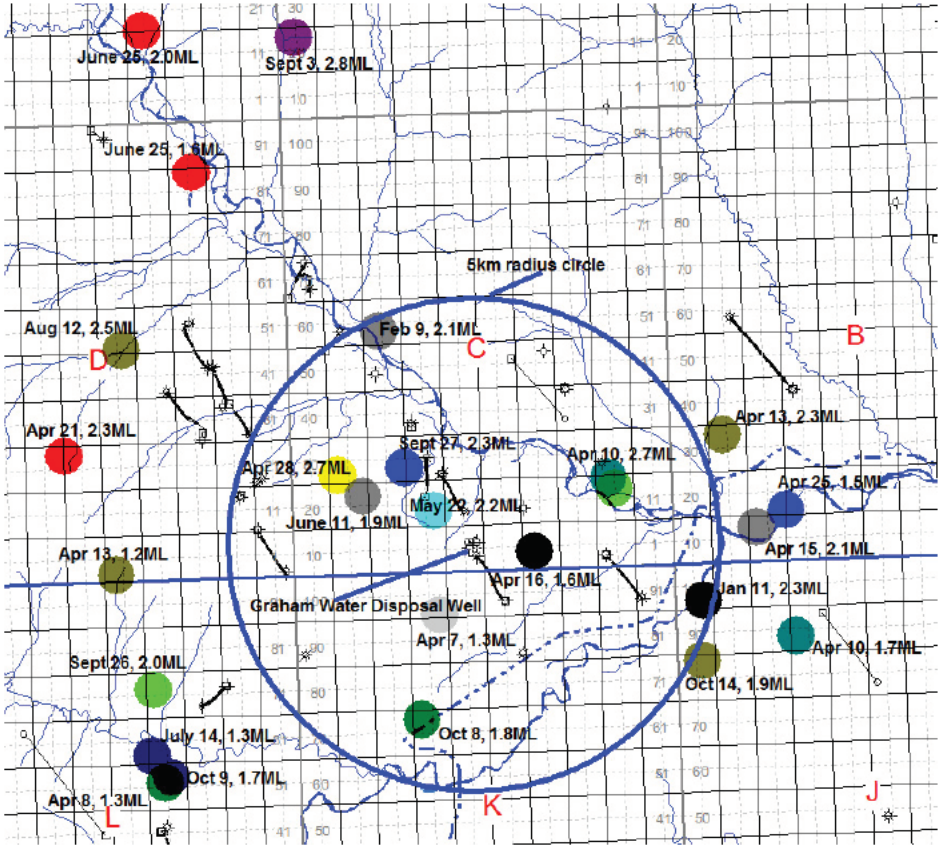
Pintail– 12 NRCan recorded events recorded near Pintail (Jan 19, 2013 to Nov 1, 2014)



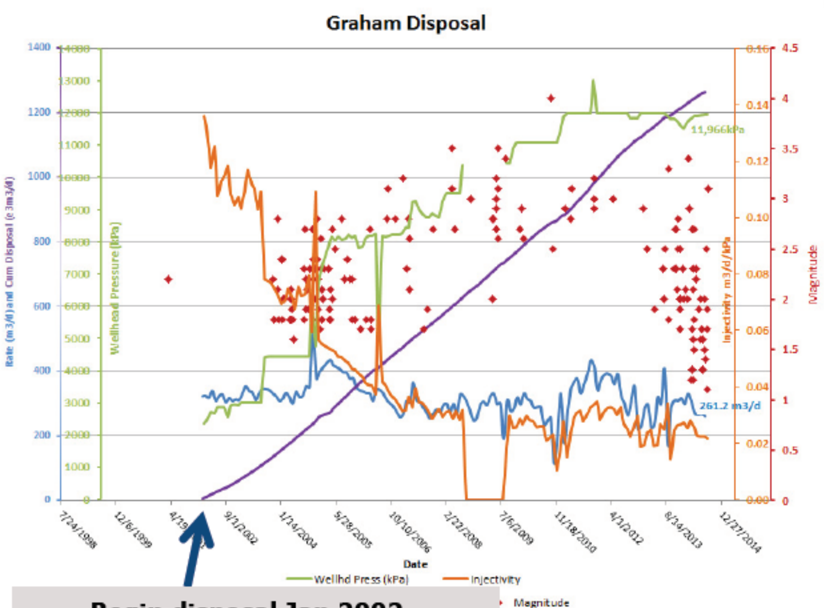


Begin disposal Aug 2012

9. Graham – March 2001-December 2014 (Wastewater Disposal Induced Seismicity)



Graham area, 197 NRCan recorded events, mag 1.1 to 4.0ML, Nov 2, 2003 - Dec 2014 (only 2014 events shown on map)



- Begin disposal Jan 2002
- First induced event recorded Nov 4, 2003

Events red diamonds