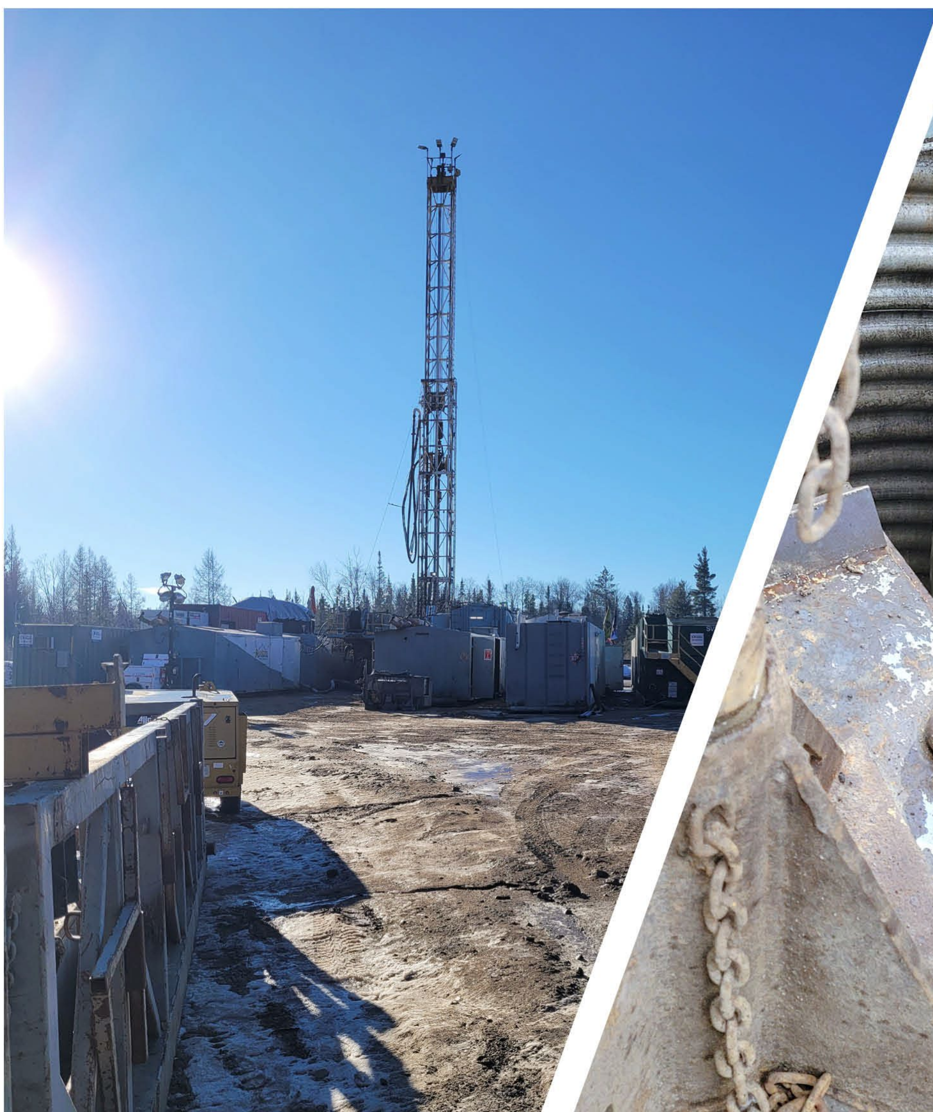
MINNESOTA

Gas Resources Technical Advisory Committee (GTAC)

Recommendations and Statutory Language for Permitting Gas Resource Development Under a Temporary Regulatory Framework



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01/15/2025

Legislative Charge

Minnesota Laws of 2024, Chapter 116, Article 3, Section 55 (e)

By January 15, 2025, the commissioner must submit to the chairs and ranking minority members of the legislative committees and divisions with jurisdiction over environment recommendations for statutory and policy changes to facilitate gas and oil exploration and production in this state and to support the issuance of temporary permits issued under the temporary framework in a manner that benefits the people of Minnesota while adequately protecting the state's natural resources.

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As requested by Minnesota Statute 3.197: This report cost approximately $20,000 to prepare, including staff time, printing and mailing expenses.

Table of Contents

Executive Summary

The Minnesota Department of Natural Resources (DNR), on behalf of the state's Gas Resources Technical Advisory Committee (GTAC), is submitting this report to the State Legislature with recommendations and draft legislative language for a temporary framework to regulate development of gas resources like hydrogen or helium in Minnesota.

GTAC includes staff from the DNR, Pollution Control Agency, Environmental Quality Board, Department of Health, and Department of Revenue. This multi-agency committee was tasked with developing recommendations and draft legislative language for permitting gas resource development under a temporary regulatory framework. If enacted by the legislature, the temporary regulatory framework will be in place while state agencies write permanent rules to ensure that the development and management of gas resources within Minnesota are environmentally sound, protective of human health, and beneficial to the state and local communities.

A set of draft recommendations and statutory language was completed in November 2024. This draft was sent to Minnesota's Tribal governments for their review and input. A twenty-one-day public input period ran from December 2 to December 23, 2024. In-person public meetings in Biwabik and Eagan were held during this input period, providing opportunities to engage with GTAC members and submit public testimony through a stenographer. GTAC considered the input within thirty-eight submissions and more than 450 unique inputs from the Tribes, stakeholders, and the public.

Submission of this legislative report does not activate a temporary regulatory framework or allow applications for gas resource development permits to be submitted. The recommendations and draft legislative language must be considered by the legislature. If the temporary regulatory framework for gas development projects during rulemaking is not enacted by the legislature, the 2024 moratorium on oil and gas production stands, and permits will not be issued until the rulemaking process is completed in 2026.

Introduction

The historical absence of oil and gas production in Minnesota is not due to lack of effort. According to the Minnesota Geological Survey, hundreds of exploratory oil and gas wells have been drilled in our state since the 1880's. While several small natural gas deposits were discovered, none proved to be commercially viable.

The belief that Minnesota would never see commercial gas production within its borders was challenged in February 2024, when drilling confirmed an accidental discovery of helium gas in the northeastern part of the state in 2011 (Figure 1). The helium exploration company that drilled that boring suggested that they might be able to start commercial production of not just helium, but also carbon dioxide, within twelve to eighteen months, of their February 2024 drill program. At the same time, exploration companies were identifying drilling targets for geologic hydrogen in Kansas and Nebraska, along a geologic formation known as the Midcontinent Rift System that extends northwards into Minnesota, from the Iowa border up to Lake Superior (Figure 2). The United States Geological Survey had also identified the Midcontinent Rift System as one of the top two prospective regions for geologic hydrogen production in the United States.

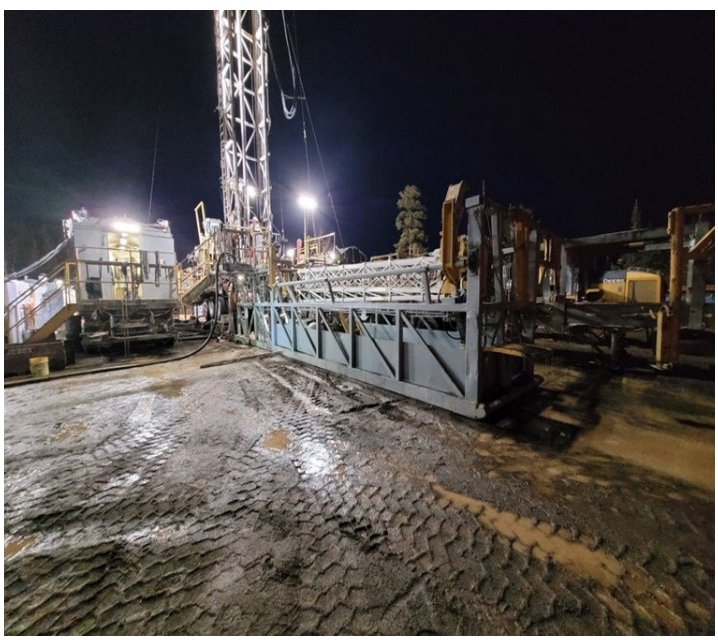

Figure 1 Drill site for Pulsar Helium's Jetstream #1 well, which in 2024 confirmed the accidental discovery of helium in northeast Minnesota.

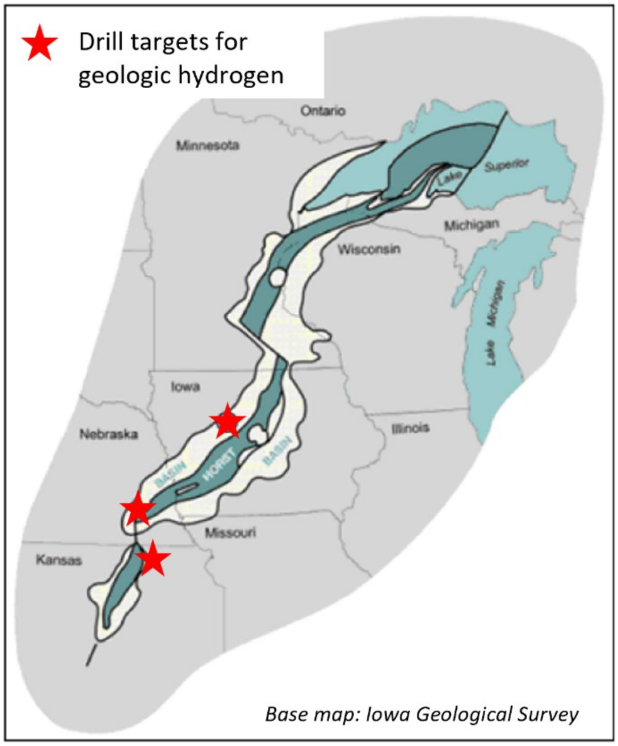

Figure 2 Map of the Midcontinent Rift System, with current drill targets for geologic hydrogen resources.

Given the historical absence of gas production in the state, Minnesota lacks a regulatory framework that would support these emergent industries, properly protect natural resources and human health, develop a fair royalty structure on state-managed lands and ensure the conservation of the state's natural resources. The Minnesota legislature acted on the need to create a regulatory framework for gas resource development by enacting legislation on May 22, 2024. This legislation included a moratorium on oil and gas production in the state without a permit from the Department of Natural Resources (DNR) and granted the DNR and other state agencies expedited rulemaking authority to establish rules within twenty-four months that are necessary for that regulatory framework.

Given the potential opportunity to commercially develop helium resources sooner than 24 months, the legislature also directed the DNR to form and lead the Gas Resources Technical Advisory Committee (GTAC). The multi-agency committee was charged with developing recommendations for permitting gas development projects during rulemaking under a temporary regulatory framework and including draft legislative language in each recommendation. The DNR was required to deliver these recommendations and statutory language to the legislature by January 15, 2025.

This report, submitted by the commissioner of natural resources to the State Legislature, contains the required recommendations and draft legislative language. This introductory section provides information about GTAC and the methods it used to develop recommendations and statutory language. It also describes how GTAC's efforts benefited greatly from the legal and technical expertise of energy sector consultants, and from the input it received from Tribes in Minnesota, stakeholders[1], and the public. The appendices that follow the recommendations and draft legislative language include the "Best Practices" report prepared by GTAC's consultants, compiled input received during a public input period, and tables that compile individual comments from each input submission and document how they were considered by GTAC during the finalization of this report.

[1] The enabling legislation stated the advisory committee should consider public testimony from "stakeholders". While GTAC members understand that many consider "interested parties" to be a broader alternative to "stakeholders" that reflects the comprehensive approach we took to gather feedback, this report uses the legislative language for clarity.

Enabling Legislation

The legislation that was enacted in May 2024 to support a regulatory framework for gas production in Minnesota included the following elements:

- Allows the DNR under MS 93.25 to lease state-managed lands to prospect for oil and gas resources. Leases must be approved by the Executive Council. This will allow both royalty disbursements and rental payments to state and local governments under MS 93.22.
- Requires the DNR to amend and adopt certain rules pertaining to oil and gas production and allows other state agencies to adopt or amend rules for oil and gas production (see MS 93.514). Rulemaking must be completed within 24 months (by May 2026) of enactment under expedited procedures.
- Prohibits oil and gas production in the state without a permit from the DNR and prohibits issuance of these permits until rules are adopted, unless the permitting process has been approved by the legislature (MS 93.513).
- Session law directs the DNR to create the multi-agency Gas Resources Technical Advisory Committee (GTAC) to make recommendations to the DNR commissioner that would guide the creation of a temporary regulatory framework that would govern, after legislative approval, permitting of gas production projects during the rulemaking process.
- Requires GTAC to hold one public meeting on this topic and consider public testimony from stakeholders and Tribes.
- Directs the DNR commissioner to submit recommendations and draft legislative language to the State Legislature that reflect GTAC recommendations by January 15, 2025.
- Provides appropriations to support the identified work per Law of Minnesota 2024, Ch. 116, Art. 3, Secs. 21-25. Upon enactment, a one-time appropriation of $768,000 was issued to DNR to fund GTAC. A second appropriation of $2,406,000 was made available to DNR on July 1, 2024, for the development of a regulatory framework for gas production and for rulemaking over the ensuing twenty-four months.

Timelines for Temporary and Permanent Regulatory Frameworks

The timing of GTAC's work was set up by the enabling legislation to run in parallel with expedited rulemaking (Figure 3). GTAC must finalize its recommendations and statutory language and the DNR must submit them to the State Legislature by January 15, 2025. If the legislation is not enacted for permitting gas development projects during rulemaking, the 2024 moratorium on oil and gas production stands, and permits cannot be applied for until the rulemaking process is completed in 2026 (legislative special sessions notwithstanding).

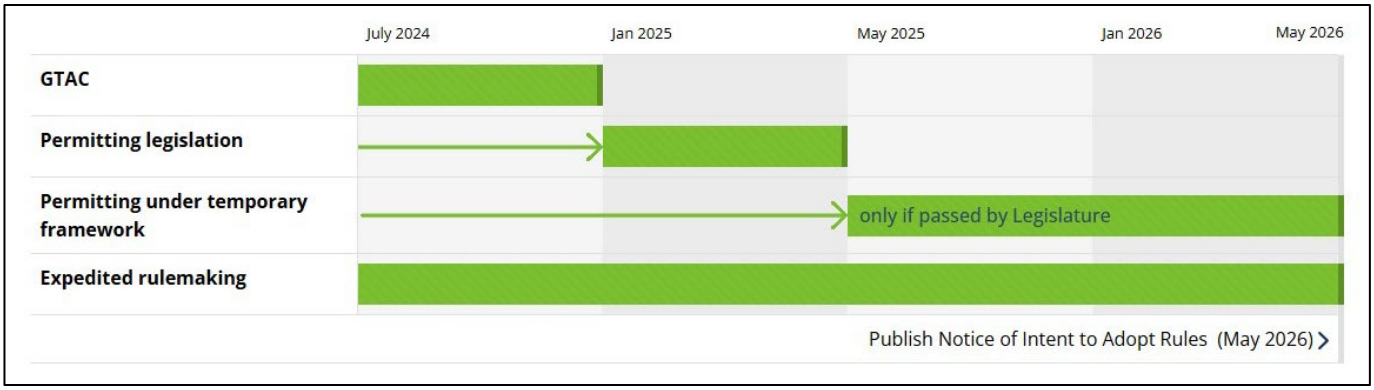

Figure 3 Timeline for GTAC and expedited rulemaking.

Committee Organization and Support

The State Legislature directed the DNR commissioner to create GTAC with members drawn from organizations listed within the enabling legislation. Seven individuals were invited to participate, representing five state agencies with regulatory and rulemaking authority for gas resource development. The state agencies are:

- Minnesota Department of Natural Resources (DNR)
- Minnesota Department of Health (MDH)
- Minnesota Environmental Quality Board (EQB)
- Minnesota Pollution Control Agency (MPCA)
- Minnesota Department of Revenue (DOR)

Figure 4 GTAC members and colleagues visit the Pulsar Helium site in December 2024.

Staff support for GTAC was provided by the DNR with planning, coordinating, and communications efforts which were integral to the committee's success. Committee members also benefited from the work done by support teams within their own agencies.

The DNR also engaged external consultants to support GTAC's work. DeYoung Consulting Services (DYS), a consulting firm based in Minneapolis, was hired to plan and facilitate GTAC meetings and create report content. DYS staff served as a consistent and thoughtful sounding board for agency discussions, tracked the fast-paced and complex conversations via regular meeting minutes, and helped GTAC plan and execute various engagement and outreach activities. DYS also served as a primary contractor that managed the subcontracted Colorado-based legal and technical experts from Jost Energy Law PC, Aota Technical LLC, and the law firm of Williams, Weese Pepple & Ferguson. This multi-disciplinary team of specialists in the regulation and permitting of helium production projects (and the oil and gas industry overall) developed a report on regulatory best practices (Appendix A) that was tailored to meet GTAC's needs and goals.

Workflow and Processes

GTAC's kick-off meeting was held in-person on July 23 at the DNR Central Office in St. Paul. The weekly meetings that followed had a hybrid format that accommodated committee members that work outside of the Twin Cities Area. After the first few weeks, individual GTAC members invited a relatively small number of colleagues from their agency support teams to join the weekly meetings to provide agency staff support more effectively, as needed. DYS staff led each meeting as facilitators and kept meeting notes; individuals from the team of subcontracted experts also remotely attended meetings to both answer questions and better understand what GTAC members needed in terms of technical support and to offer a base level understanding of how the regulators and regulated parties in states with oil and gas resources went about their work.

GTAC members decided to divide the work they were tasked to undertake and the time available for that work into five different phases:

- **Phase 1: Discussion of pertinent topics.** GTAC reviewed and discussed pertinent gas production topics that are relevant to creating a temporary regulatory framework. Each GTAC member presented information from their agency's perspective. Typically, one meeting was scheduled for each agency's presentation, including time for clarifications and questions.
- **Phase 2: Draft recommendations and statutory/policy changes.** GTAC members worked internally with their support teams and agency leadership to draft, discuss, and revise recommendations and statutory/policy changes. GTAC discussed each agency's emerging drafts and leadership input over several meetings.
- **Phase 3: External review and input.** GTAC completed a draft set of recommendations and related statutory language on November 15 and sent this compilation to Tribes in Minnesota for review and input. On December 2, the GTAC website was launched in conjunction with the start of a twenty-one-day public input period. During that time, GTAC held in-person public meetings in Biwabik and Eagan. Input from the Tribes, stakeholders, and the public was accepted through December 23. This input is available on the GTAC website.
- **Phase 4: Analysis of input and finalization of report.** GTAC members reviewed and discussed the input that was provided, as it was being received, and grouped comments by themes to help in that analysis. GTAC members considered all input as they revised their draft recommendations and statutory language, with their considerations documented for each theme (Appendix C).
- **Phase 5: Finalize DNR Commissioner's recommendations and report.** GTAC continued to meet during the input and revision process until a draft finalized report was sent to each agency's

leadership team for review. A final report was then prepared and submitted to the commissioner of natural resources.

Draft Recommendations and Outreach

Draft GTAC Recommendations

The State Legislature required GTAC to provide recommendations and statutory language on the following topics:

- Statutory and policy changes that govern permitting requirements and processes;
- Financial assurance;
- Taxation;
- Boring monitoring and inspection protocols;
- Environmental review; and,
- "(O)ther topics that provide for gas and oil production to be conducted in a manner that will reduce environmental impacts to the extent practicable, mitigate unavoidable impacts, and ensure that the production area is restored to a condition that protects natural resources and minimizes harm and that any ongoing maintenance required to protect natural resources is provided.

GTAC members, in support of the goal of a robust temporary framework that could regulate gas production during rulemaking, developed recommendations and statutory language for related topics outside of this required set. Examples of these additional topics include siting and setbacks for gas development projects, gas well construction methods, and policies and procedures for pooling and spacing.

GTAC completed a draft set of recommendations with draft legislative language for a temporary regulatory framework for permitting gas development projects during rulemaking on November 15, 2024, less than four months after its first meeting in July. The draft contained fifty-four recommendations, divided into sections based on the GTAC agency that developed them. A rationale for each recommendation was provided, and there were references to the corresponding new or amended statutory language that an agency had created for that recommendation. All of the statutory language developed by the five GTAC agencies was combined into a single compilation that was arranged based on statutory chapter numbers.

While the enabling legislation required each GTAC recommendation to include "draft legislative language," the draft document used the term "draft statutory language." The two terms are interchangeable. At the same time, many of GTAC's recommendations involve new or amended "permanent" statutes that would not expire once rules for a permanent regulatory framework are adopted. This statutory language is, for the most part, needed to support the expedited rulemaking requirements in the enabling legislation.

GTAC Outreach Activities

This subsection describes how the state engaged with Tribal governments on gas exploration and development topics and characterizes GTAC's outreach efforts during the public input period.

The purpose of GTAC's elevated level of engagement with the Tribes, stakeholders and the public was to:

- Provide information about GTAC's recommendations for the development of a temporary regulatory framework during rulemaking for gas resource development;
- Provide more general information about the enabling legislation and expedited rulemaking;
- Gather input from the Tribes, stakeholders and the public on GTAC's draft recommendations and statutory language;
- Determine, based on this input, whether there were changes to the draft recommendations and statutory language that needed to be considered; and,
- Collect any other questions and comments that might inform the preparation of a final report and expedited rulemaking.

The State Legislature established outreach requirements for GTAC in its enabling legislation:

- "The temporary framework must consider public testimony from stakeholders and Tribes;" and,
- "…the committee must hold at least one public meeting on this topic."

As described below, GTAC's outreach and engagement with the Tribes, stakeholders and the public exceeded these legislative requirements. The Tribes were provided approximately five weeks to review GTAC's draft recommendations and provide input, while stakeholders and the general public had three weeks to review and submit their public testimony. And instead of satisfying the minimum requirements by holding a single on-line meeting for the public to offer input, GTAC held two in-person public meetings and offered a 21-day public input period, with multiple options for submitting input.

Tribal Engagement

The State of Minnesota began engagement with the Tribes on gas exploration activities and potential regulations before the enabling legislation was passed and GTAC was formed.

Tribal representatives were given an opportunity to review and provide feedback on the draft recommendations before they were provided to stakeholders and the public. Tribes were invited to continue providing feedback during the public input period. Additionally, GTAC conducted the following activities engagement activities:

- Updates at State/Tribal meetings occurred on April 9, June 4, August 13, and December 3, 2024;
- GTAC members were present at the State/Tribal mining meeting on October 8, 2024 for questions;
- GTAC held a Tribal Leadership update meeting on November 13, 2024;
- GTAC distributed draft recommendations and statutory language to Tribes on November 15, 2024;
- GTAC sent an email to stakeholders and members of the public via a GovDelivery notification, inviting them to provide input between December 2 - 23, 2024; and,

- GTAC published a webpage on December 2, 2024, and held public meetings in Biwabik, MN and Eagan, MN on December 12 and 17, 2024.

Public Input Period

A twenty-one-day public input period was held between December 2 – 23, 2024. Information about this input period was shared via a state-wide press release, as well as through a GovDelivery notification sent to an established list of more than 10,000 subscribers interested in news from the DNR's Lands and Minerals division. Other GTAC agencies sent the same GovDelivery messages to their own subscriber lists.

Input was accepted in a number of ways:

- Via a dedicated email address;
- By mail to the DNR Central Office;
- Through an online form; and
- At the in-person public meetings using the on-site stenographer.

Website

Prior to the public input period GTAC delegated the DNR to develop a cross-agency [website on the Regulatory Framework for Developing Gas Resources in Minnesota]. This website provided a way to share some background information on the topic, the creation of GTAC, the legislative mandate, and the draft recommendations and statutory language that GTAC developed. These recommendations and statutory language were updated with the final report presented to the Legislature. The cross-agency website was designed to be used after GTAC completes its tasks, throughout the upcoming rulemaking process.

Figure 5 Home page for GTAC's website, which will also be used for expedited rulemaking.

Public Meetings

Two in-person meetings were held during the twenty-one-day input period: one in Biwabik, MN on December 12, 2024, and one in Eagan, MN on December 17, 2024. Both meetings were open to the public between 6-9 pm; they offered the opportunity to listen to an overview of GTAC and the process of drafting the published recommendations and statutory language, as well as to engage with GTAC members from all five agencies involved.

To facilitate submission of input, there were QR codes visible around the room and on agency tables, directing participants to the online input form. A laptop was also available for participants to view the website (described above), read through the recommendations document, or provide input via the online form. A stenographer was available at both meetings and received input only once during the Biwabik meeting. Conversations with agency staff were a central part of both meetings.

Figure 6 GTAC members engaging stakeholders and the public during the December 12 public meeting in Biwabik, MN.

Input on Draft Recommendations and Statutory Language

GTAC received thirty-eight (38) submittals with input on its draft recommendations and statutory language. Some of these submissions also included comments and suggests that were broader in scope (e.g., whether there should even be a temporary regulatory framework for gas resource development while rules were being written).

As previously mentioned, GTAC offered the Tribes, stakeholders and the public multiple ways to submit their input. Figure 7 provides details on how input was delivered for GTAC consideration. Most of the submissions were made via electronic mail, and most of those emailed submissions provided input within attached letters in PDF format. There was only one verbal submission logged by a stenographer during the two public meetings. None of the submissions were delivered via U.S. mail, although two sources mailed hardcopies of a digital document attached to an email.

Submission method	Count
Email	26
Online form	11
Stenographer	1
Regular mail	0
Total	**38**

Figure 7 Count of public input by submission method.

Tribal Input

Five Tribes provided input letters before the start of the 21-day public input period on December 2. Input was received from:

- Fond du Lac Band of Lake Superior Chippewa;
- Grand Portage Band of Lake Superior Chippewa;
- Leech Lake Band of Ojibwe;
- Mille Lacs Band of Ojibwe; and
- White Earth Reservation

During the 21-day public input period, the Grand Portage Band of Lake Superior Chippewa and Mille Lacs Band of Ojibwe offered second input letters. GTAC also received input from the 1854 Treaty Authority. While the 1854 Treaty Authority supports the Bois Forte and Grand Portage bands on ceded territory issues, they did not speak for them, and the input they offered came from their own perspective. Given that the 1854 Treat Authority is an inter-tribal resource management agency, GTAC decided to consider its input alongside the comments provided by the five recognized Tribes.

Stakeholder Input

At the conclusion of the public input period, GTAC members identified eight (8) of the thirty-eight submissions as stakeholder input:

- Iron Range Exploration LLC
- Mining Minnesota;
- Pulsar Helium;
- Range Association of Municipalities and Schools (RAMS);
- RGGS Land & Minerals, LTD., L.P.;
- U.S. Forest Service;
- Vema Hydrogen, Inc.; and
- WaterLegacy

GTAC identification of these eight organizations as stakeholders does not imply that those who submitted other non-Tribal input are not stakeholders. GTAC members appreciated all of the provided input, and considered each submission equally, regardless of how they were categorized. One of the main criteria used was whether the identity of a potential “stakeholder” could be verified. All of the organizations listed above provided their input in letters written on letterhead that were saved as PDF documents and attached to emailed messages. Input submitted using the on-line form was, by contrast, collected anonymously, and any self-identifiers provided within an on-line submission could not be verified.

There were three exploration and development companies within the group of identified stakeholders. Pulsar Helium has an active helium development project in northeast Minnesota, while Vema Hydrogen and Iron Range Exploration self-identified as companies interested in the potential development of Minnesota’s hydrogen resources. A fourth organization, Mining Minnesota, is a trade group that focuses on supporting the development of the state’s mineral resources. RGGS is a land and mineral interests owner whose holdings include the leased parcel of land that Pulsar Helium drilled their appraisal well on in February 2024. The U.S. Forest Service manages the Superior National Forest and federal lands within Pulsar Helium's area of interest, the Range Association of Municipalities and Schools represents the interests of schools and local government units in northeast Minnesota, and WaterLegacy is "an organization formed to protect Minnesota water resources and communities." The letterhead submissions of the eight identified stakeholders are compiled and are available on the GTAC website.

Public Input

Twenty-two of the thirty-eight submissions with input on GTAC's draft recommendations and statutory language were from members of the public. One of the ten submissions sent by email provided input in an attachment. The emailed input without attachments and the twelve public submissions made using the on-line form were generally smaller in scope and tended to focus on a single point or comment. The emailed attachments and a table with the other public input are available on the GTAC website.

Consideration of Received Input

The process used to log each submission, identify individual pieces of input, and consider them was based on methods developed by the DNR to evaluate public comments for large projects:

- Break down each submission into individual comments;
- Group comments by theme and subtheme; and,
- Distribute to GTAC members for consideration based on topic/recommendations.

A table that compiles the 450+ individual comments within the thirty-eight submissions, and identifies how they were grouped by theme and subtheme for consideration, is provided in Appendix B. A separate table that shows how each theme and subtheme was considered by GTAC members is included within Appendix C.

Final Report

GTAC members and their agency support teams determined whether their draft recommendations and statutory language needed to be revised based on the input received. Some revisions to the draft recommendations and statutory language were made based on other considerations, such as review of the finalized regulatory best practices report (Appendix A). A small amount of content was also added to the revised recommendations and statutory language. A draft final report was prepared, and reviewed by the leaderships of each GTAC agency before a final report was submitted to DNR. The DNR then prepared this final report for submission to the State Legislature. This final report is based on GTAC's understanding of the gas resource development industry at the time of its publication.

One of the stakeholders urged GTAC to offer a second public input period, so that they and others could review and comment on the revised recommendations. Aside from the fact that there was simply not enough time for a second public input period, GTAC notes that the submission of its finalized recommendations to the legislature is not the end of the regulatory process. None of GTAC's recommendations have any standing unless the legislature decides to take them up within proposed legislation, and if that happens, the legislative hearings that will follow a bill's introduction will provide opportunities for the Tribes, stakeholders, and the public to further weigh in on any draft legislation.

Recommendations

Minnesota Department of Natural Resources

Agency background

The Gas Resources Technical Advisory Committee (GTAC) was directed by its enabling legislation to make recommendations "…relating to the production of oil and gas in the state to guide the creation of a temporary regulatory framework that will govern permitting before the rules authorized in Minnesota Statutes, section 93.514, are adopted." Recommendations are required by the enabling legislation to address statutory and policy changes for the following:

- Permitting requirements and processes;
- Financial assurance;
- Taxation;
- Boring monitoring and inspection protocols;
- Environmental review; and,
- Other topics that provide for gas and oil production to be conducted in a manner that will reduce environmental impacts to the extent practicable, mitigate unavoidable impacts, and ensure that the production area is restored to a condition that protects natural resources and minimizes harm and that any ongoing maintenance required to protect natural resources is provided.

The Department of Natural Resources has recommendations based on its regulatory oversight responsibilities that cover most of these required topics. A breakdown of covered topics and the associated DNR recommendations is provided in the following table:

Required Topic	**DNR Recommendations**
Permitting requirements and processes	Recommendations DNR-3 to DNR-13
Financial assurance	DNR 14 to DNR-17
Taxation	No DNR recommendations on this topic
Boring monitoring and inspection protocols	No DNR recommendations on this topic
Environmental review	DNR-11
Other topics	DNR-1, DNR-2

The DNR is also making an appropriation request and recommendations for topics that weren't identified in the enabling legislation, but are needed to support a temporary regulatory framework for permitting gas resource development projects during rulemaking:

- Pooling and Spacing (recommendations DNR-18 to DNR-28);
- Gas development on forfeited severed mineral interests (recommendation DNR-29); and,
- Appropriation request for a gas resource development permitting program (recommendation DNR-30)

Recommendation DNR-1: The DNR recommends a focus on gas resource development during construction of a temporary regulatory framework and during expedited rulemaking.

Recommendation

The DNR recommends that newly proposed or amended statutes and rules developed under expedited rulemaking should focus solely on the development of the state's gas resources.

Draft statutory language: Chapter 93.

Rationale

There is not currently any indication that there are crude oil resources in the state (see Minnesota Geological Survey, 1984), and there's currently no industry interest in drilling for oil in Minnesota. Since Minnesota does have a known helium resource and there is high potential for natural hydrogen resources, the state should focus statutory and rulemaking efforts on gas production. If crude oil resources are discovered, or there is future interest in oil exploration in the state, rules for gas production could be amended to include oil.

Gas Wells

Recommendation DNR-2: Amend expedited rulemaking authority granted to the DNR for oil and gas production.

Recommendation

DNR recommends that statutory language requiring the commissioner of natural resources to write rules for "conversion of an exploratory boring to a production well" and "well abandonment" be struck, and that expedited rulemaking authority be added for leasing state-managed mineral interests for oil and gas development.

Draft statutory language: 93.514

Rationale

Under 93.514, "the commissioner of natural resources must adopt or amend rules pertaining to the conversion of an exploratory boring to a production well, pooling, spacing, unitization, well abandonment, siting, financial assurance, and reclamation for the production of gas and oil."

MDH is recommending draft legislation that would prohibit conversion of an exploratory boring into a gas well (see 103I.601 subd. 12 in the draft statutory language section of this report). In line with that recommendation, the DNR proposes that the statutory language requiring it to write rules for converting an exploratory boring into a production well should be struck, as it will no longer needed.

MDH also recommends that it be given rulemaking authority for the abandonment of gas wells (see MDH recommendation MDH-15), providing it the same kind of regulatory oversight that it currently holds for water wells and exploratory borings. The DNR therefore recommends that statutory language requiring it to write rules for well abandonment also be struck (with that authority transferred to MDH). This will provide for a single set of rules governing the proper sealing of all gas wells, including wells that failed to yield commercial quantities of gas (i.e., “dry holes”), or gas wells that an operator chose not to put into production, for one reason or another.

The abandonment of gas production wells falls within the scope of reclamation activities and financial assurance requirements that are under DNR’s purview. A person that applies for a gas resource development permit will be required to include well abandonment within their required reclamation plan, and the cost of abandoning those well must be included within the reclamation cost estimate that is subject to financial assurance (guaranteeing that funds will be available to seal the wells if they are abandoned or orphaned by the operator). Under a gas resource development permit, an operator desiring to seal one or more of their gas wells will be directed to notify the department of health and follow MDH well sealing requirements. Project closure and the release of financial assurance that targets well sealing will not be provided until MDH notifies DNR that the gas wells have been properly sealed.

Finally, the commissioner of natural resources was granted statutory authority to lease “lands belonging to the state or in which the state has an interest” for “gas or oil exploration and production” under 93.25 and 93.516. While amending 93.25 to include oil and gas leases gives the DNR rulemaking authority to write rules for leasing state-managed mineral rights for gas or oil exploration and production, the DNR recommends that it be given expedited rulemaking authority for its oil and gas lease program under 93.514 subd. 4. This will allow the DNR to more efficiently manage all of its rulemaking activities for oil or gas production under a single set of procedures. This recommendation would not involve additional time for rulemaking under 93.514, and the DNR would use this rulemaking authority to write rules for lease program topics such as application procedures, a model lease form, and public sales of oil and gas leases.

Permitting and Related Processes

Recommendation DNR-3: Use existing statutes and rules for permitting mine projects in Minnesota as a model for permitting requirements and policies for gas resource development projects, with modifications as needed to reflect the differences between the development of gas resources and mining metallic minerals.

Recommendation

Use the framework in existing statutes and rules for the evaluation and permitting of nonferrous mining projects as a model for the creation of new statutes related to gas resource development, with modifications as needed to reflect the differences between the development of gas resources and mining metallic minerals. This recommendation is for both the temporary and post-rulemaking regulatory frameworks.

Draft statutory language: 93.5171 to 93.5179

Rationale

Minnesota lacks a regulatory framework for permitting gas resource development projects. It does, however, have a robust regulatory framework for permitting other types of mineral resource production, such as nonferrous metallic mine projects (see Mn Statutes 93.44-93.51, Mn Rules Chapter 6132). While DNR could recommend a regulatory framework that is created from scratch and patterned after the permitting requirements and procedures in other U.S. states (e.g., North Dakota, Colorado, Michigan) the DNR believes that new statutes and rules for permitting gas resource development in Minnesota should closely follow comparable regulations for evaluating and permitting mining projects, with modifications as needed to reflect the differences between gas resource development and the mining of solid minerals. This approach provides:

- a degree of uniformity in how natural resource development projects are evaluated and, if they meet all requirements, permitted;
- statutory language and rules that are familiar to the legislature and Minnesotans, and,
- a regulatory design that has been tested in the courts.

Recommendation DNR-4: Permits for gas resource development projects should be required before gas wells are drilled.

Recommendation

Permits for gas resource development projects should be required before a gas well is drilled, rather than after drilling but before that gas well goes into production and extracts commercial quantities of a gas resource. This recommendation is for both the temporary and post-rulemaking regulatory frameworks.

Draft statutory language: 93.51711, Subd. 11 and 93.5174

Rationale

DNR recommends a permitting process to be completed by DNR for a gas resource development project. This process will be preceded by environmental review. Once a gas resource development permit is approved by DNR, the permittee would then submit notification to MDH before drilling (see MDH recommendation MDH-5).

Conducting environmental review and permitting before a gas well is drilled ensures that all proper environmental and public health and safety measures are in place and allows an operator to bring that gas well (once it is drilled and determined to be commercially viable) into production relatively quickly, since it avoids a pause between drilling a gas well and being permitted to put the well into production.

Recommendation DNR-5: Permits for gas resource development projects should apply to "gas resource development locations," where gas development operations disturb the ground surface.

Recommendation

A gas resource development permit should be required whenever gas resource development operations would disturb the ground surface. These areas, defined as "gas resource development locations," are distinct from spacing units or extraction areas that are the undisturbed surface expression of subsurface gas extraction. This recommendation is for both the temporary and post-rulemaking regulatory frameworks.

Draft statutory language: 93.5174

Rationale

Gas wells are typically drilled on drill pads up to ten acres in size and, if the gas well goes into production, the site might be in operation for several years. As a result, the DNR is recommending that environmental review and permitting take place at gas resource development locations before any gas wells are drilled. DNR recommends that these evaluations assess all gas resource development locations, including proximal ancillary buildings such as centralized gas enrichment plants that do not sit on a gas well's drill pad.

Recommendation DNR-6: The commercial extraction of gas resources should be limited to gas wells at permitted gas resource development locations.

Recommendation

The commercial extraction of gas resources from exploratory borings should be prohibited by statute. This recommendation is for both the temporary and post-rulemaking regulatory frameworks.

Draft statutory language: 93.5174

Rationale

Gas wells require blowout prevention systems and construction materials and methods that protect workers and the environment from potential risks associated with intersecting pressurized gas reservoirs. One need not look beyond Minnesota's borders to gather support for this assertion; the 2011 discovery of helium in Minnesota occurred when a drill rig designed for metallic mineral exploration encountered a pressurized gas pocket that, when released, reportedly had enough energy to push the drill rod and mud more than 1,700 feet up to the surface, and then launch that drill rod into the air. The construction materials and methods typically used for drilling water wells and exploratory borings are also suboptimal for the production of gas resources, which increases the risk of groundwater impacts and cross-aquifer contamination. It therefore makes sense to limit gas production to gas wells located at permitted gas resource development locations. This ensures that operators looking to construct gas wells use the appropriate drilling equipment, materials, and methods, and that their drill locations are appropriately sited and permitted.

Recommendation DNR-7: A gas resource development permit applicant must pay an application fee, annual permit fee, and, if necessary, a supplemental application fee.

Recommendation

The DNR recommends a $50,000 application fee for a gas resource development permit as well as the ability to assess supplemental fees to cover the costs of reviewing an application above the application fee amount. The DNR also recommends that permittees for gas resource development projects pay a $75,000 annual permit fee. These recommendations would apply to both the temporary and post-rulemaking regulatory frameworks.

Draft statutory language: 93.5175

Rationale

The DNR's recommended $50,000 application fee is, in practice, not so much a fee as it is an advance payment for the costs incurred by the DNR to review a permit application and prepare a draft permit. When the DNR determines the reasonable costs, the $50,000 application fee is subtracted from the total, and the applicant is assessed the balance (if due). The purpose of this application fee is to demonstrate firm intentions by the applicant, and to cover agency costs if the applicant decides to withdraw their application before a supplemental application fee is paid (but after the agency has incurred staff time and costs).

Should the reasonable costs of reviewing and preparing a gas resource development fee be less than the nonrefundable application fee, the remaining money may be used by the commissioner to cover the indirect costs incurred by the agency that may not be readily identifiable but are nonetheless necessary for permit review and preparation (e.g., wages for operational services, business office and administrative staff, office rent, equipment).

In Minnesota, annual permit fees for mining projects defray the salary costs incurred by the DNR to administer the permitted operations and complete tasks such as site inspections and the review of annual reporting. It is similar in scope and purpose to a supplemental application fee, except that it is a set fee that varies based on the type of mining operation involved. Annual permit fees range from $1000 per year for peat mining to $75,000 for nonferrous metallic mining operations. This range reflects the amount of staff time required to administer a permit, but also reflects, in part, the value of the natural resource that is developed under the permit.

The DNR recommends that permittees for gas resource development projects pay a $75,000 annual permit fee. While this is most likely higher than annual fees assessed to operators of oil and gas projects in other U.S. states, there are multiple reasons why this amount is justified:

- In most states with oil and gas resources, the programmatic costs of regulating oil and gas production can be borne by dozens or even hundreds of operators who are producing oil and gas from thousands of wells. In Minnesota, there is currently only one operator developing a potential gas resource, and it is uncertain whether the number of operators and gas wells and gas resource development projects will grow dramatically anytime soon.
- Gas resource development is a nascent industry in Minnesota, with a regulatory framework that is just as new. The costs required to build out a regulatory program of staff with expertise in gas resource development are not experienced in states with a mature oil and gas industry.
- Some states that do not charge annual permit fees for their gas regulatory programs and instead generate program-supporting revenue by other means, such as a production-based fee (e.g., Michigan), or a severance tax on oil and gas development (e.g., North Carolina). At this time, the DNR is not proposing a dedicated revenue stream linked to gas production.

Recommendation DNR-8: Gas resource development permits issued during rulemaking and under a temporary regulatory framework should continue to remain valid after the completion of the rulemaking process. If a gas resource project permitted under the temporary framework requires a permit amendment or substantively changes its operations after rules are promulgated, their permit would then be updated to reflect the permanent regulatory framework.

Recommendation

Gas resource development permits issued under a temporary regulatory framework should not be considered temporary, such that they would expire once rules for a permanent regulatory framework were promulgated. A person receiving a gas resource development permit should be able to operate under those permit conditions throughout the lifetime of their project, unless or until they require a permit amendment. At that point, a new permit would need to be issued based on the permanent regulatory framework.

Draft statutory language: 93.513 Subd. 2; 93.5174, Subd. 2.

Rationale

The enabling legislation for creating a regulatory framework for gas resource development in Minnesota instructed the DNR to provide recommendations and draft statutory language that would, if acted by the legislature, create a temporary regulatory framework that would, "support the issuance of permits issued under the temporary framework in a manner that benefits the people of Minnesota while adequately protecting the state's natural resources." (Laws of Minnesota 2024, Ch. 116, Art. 3, Secs. 55).

The phrase "temporary permit" could mean a) a permit issued under the temporary regulatory framework, b) a permit that is revoked once rules are promulgated, and the temporary regulatory framework is replaced by a permanent framework, or c) the permit is only valid for a fixed period of time, irrespective of the term requested by the permittee. The DNR recommends that the word "temporary" be removed from the phrase "temporary permit," to make clear that a permit issued during rulemaking will not be limited to a term less than what is proposed by the applicant, nor revoked once rules are promulgated.

Given the significant costs and the unproven nature of gas resources in Minnesota, it is important to offer a clear regulatory path to a person considering exploring for or developing gas resources in our state. The risks that a permanent regulatory framework for gas resource development would be dramatically different than a temporary framework might be a strong disincentive to invest in a project if the permittee was forced to reapply for a new "permanent" permit once rules were promulgated. On balance, a prudent operator might decide to delay investing in gas resource development until rules are promulgated.

The legislature clearly desired a viable mechanism for enabling the permitting of gas resource development projects during rulemaking. We believe that a viable permitting mechanism requires a permit that doesn't expire within months of being issued. To provide a level of regulatory certainty, a permit issued under the temporary framework should be for a term proposed by the applicant and determined necessary by the commissioner for the completion of the proposed gas resource development plan, including reclamation or restoration.

The rights of a permittee holding a permit issued under a temporary framework should not be absolute. If a permit amendment is required after rules are promulgated, it is reasonable to require the permittee to apply for a new permit under the permanent regulatory framework that covers their entire operation (instead of just that portion that triggered the need for a permit amendment). A permittee could continue operations under the original permit terms during this new permit application.

Recommendation DNR-9: A temporary regulatory framework for permitting gas development projects should include appropriate siting and setbacks.

Recommendation

Statutes that include regulatory language normally found in rules should be enacted to facilitate a robust temporary regulatory framework for permitting gas production projects. This “sunsetting” statutory language would only be in effect until rules are promulgated. For permitting gas resource development projects, the sunsetting statutory language should include setbacks and separations appropriate for gas resource locations and operations.

Draft statutory language: Section 15 of draft legislative language.

Rationale

Statutes for permitting and related processes aren’t normally meant to create a regulatory framework for natural resource development all on their own. Rules derived from statutes are needed for an effective framework for permitting gas resource development projects. That said, rules aren’t available for a temporary regulatory framework. Statutes that include regulatory language normally found in rules are therefore necessary to construct an effective temporary regulatory framework. This “sunsetting” statutory language would only be in effect until rules are promulgated. For permitting gas resource development projects, the sunsetting statutory language needs to cover siting considerations and setbacks, preproduction reports, and annual reporting requirements.

Legislation passed in May 2024 requires the commissioner to develop rules for siting gas resource development projects (93.514 subp. (4)). Gas resource development locations need to be at sites that minimize adverse impacts on natural resources and the public, with setbacks or separations that are needed to comply with environmental standards, local land use regulations, and requirements of other appropriate authorities. This need exists for a temporary regulatory framework, while rules on siting and setbacks are developed for a permanent regulatory framework.

During the public input period for GTAC’s draft recommendations and statutory language, GTAC received several comments urging DNR and GTAC to consider the differences between mining and gas production when making their recommendations for the temporary framework. This included specific concerns about the adaption of nonferrous mining rules for siting and setbacks for gas resource development projects. As a result, DNR decided to change its recommendation and now proposes the adoption of siting and setbacks specific to gas resource development within the temporary regulatory framework.

The siting and setbacks that DNR now recommends for the temporary regulatory framework divides surface lands protected by state or federal law into four groups:

- areas where gas resource development is excluded, and subsurface gas resources can’t be altered or developed (e.g., BWCA);
- areas where gas resource development locations that disturb the surface and directional drilling beneath the surface are excluded, but subsurface gas resource development is otherwise allowed (e.g., passive gas extraction under a state scientific and natural areas);
- areas that exclude gas resource development locations, but allow subsurface gas resource development and subsurface drilling activities (e.g., state historic sites); and

- areas where subsurface gas resource development is allowed, and gas resource development operations are allowed on the surface if it is the only viable location, and with commissioner of natural resources approval (e.g., Wildlife Management Areas).

DNR notes that there is a difference between allowing potential development activities and endorsing those activities. If environmental review determines that gas development would disturb or adversely impact the identified protected surface lands, permitting would require changes to the project, mitigation of impacts or may prohibit development activities altogether.

These recommended siting and setback requirements are just for the temporary regulatory framework. Siting and setbacks for a permanent regulatory framework will be established during rulemaking that must be completed by May 2026. The permanent siting and setback rules may reflect information gained if a proposed gas resource development project undergoes environmental review under the temporary framework.

Finally, some of the recommended siting and setbacks for gas development would limit activities in areas or natural features that are also protected by other federal or state laws. While they are similar to the state's rules for siting and setbacks for mine projects, these recommended siting and setbacks for gas might seem redundant or unnecessary. The DNR acknowledges these other regulatory protections and the underlying management authority (in particular, federal protections and land management responsibilities for areas such as the BWCAW). DNR's recommended siting and setback requirements would not supersede these other protections or management authorities, but would instead complement them, and provide an additional level of protection.

Recommendation DNR-10: A temporary regulatory framework for permitting gas development projects should include annual reporting requirements that are modeled after those used for nonferrous mining projects. This statutory language regarding annual reporting should sunset once annual reporting rules specific for gas resource development projects are promulgated.

Recommendation

Statutes for the temporary permitting of gas resource development projects should include annual reporting requirements that are modeled after existing statutes and rules. Since this type of language is normally found in rules, the temporary annual reporting statute should sunset once rules are promulgated.

Draft statutory language: Section 15 of draft legislative language.

Rationale

Statutes for permitting and related processes aren't enough on their own to create a robust temporary regulatory framework for permitting gas resource development projects during rulemaking. Statutes that include regulatory language normally found in rules are necessary to construct an effective temporary regulatory framework for permitting gas production projects. This "sunsetting" statutory language would only be in effect until rules are promulgated.

During rulemaking, tailored rules for annual reporting requirements for gas resource development projects will be established that reflect the nature and scope of gas resource development operations at gas resource development locations. For the purposes of a temporary regulatory framework during permitting, the DNR proposes that annual reporting requirements for permitted gas production projects model those used for nonferrous mining projects (see 6132.1300).

Recommendation DNR-11: Prior to commercial production of gas resources, a gas resource development permittee should be required (as a permit condition) to submit to the DNR data and other information derived from the gas wells drilled under the permit necessary to determine whether the associated spacing units and pool areas should be adjusted. This recommendation is only for the temporary regulatory framework, with sunsetting statutory language that expires once rules are promulgated.

Recommendation

The DNR recommends that prior to commercial production of gas resources, a permittee must (as a permit condition) submit to the commissioner test data and other information derived from the gas wells drilled necessary to determine whether the associated spacing units and pool areas should be adjusted. This recommendation is only for the temporary regulatory framework, with sunsetting statutory language that expires once rules are promulgated.

Draft statutory language: Section 15 of draft legislative language.

Rationale

An operator that proposes a gas resource development project has to identify the amount of gas their project would extract, and where those gas resources would come from (in three-dimensions). This information is critical for establishing spacing units, issuing pooling orders, and to prevent unnecessary draining of reservoirs, prevent waste, and protect human health and the environment. When permits are issued and spacing units established before the operator drills their gas wells, the engineering and geological data needed to determine production rates and extraction areas must be estimated. In established or mature well fields, there might be logs and data available from dozens or even hundreds of wells drilled into the same reservoir, which allows operators to estimate with a great deal of accuracy the production rates and extraction areas of their new gas wells. Minnesota does not have a history of gas production within established well fields in the state, or even (at present) a good understanding of where gas resources might be located, or the size and shape of any gas reservoirs. This will increase the uncertainty of applicant-provided estimates for production and extraction areas.

Until more information is available about the nature and extent of Minnesota's gas resources, the DNR recommends that gas resource development permittees submit to the commissioner, as a permit condition, a pre-production report that includes the engineering and geological data necessary to evaluate potential changes to an established spacing unit or pool unit and consider the potential impacts of bringing the project into production. This could include test data from gas wells that will be used during production. The pre-production report must compare the hard data obtained from a permittee's gas wells against any estimates submitted to the DNR before drilling.

Recommendation DNR-12: A person applying for a gas resource development permit or permit amendment should be assessed fees to recover the costs incurred for environmental review.

Recommendation
The DNR should assess the proposer of a gas resource development project the reasonable costs of preparing, reviewing, and distributing a mandated environmental assessment worksheet. No environmental review shall commence until this fee has been paid, and no state agency may issue a permit for a gas resource development project until the final costs of this environmental review have been paid in full.

This recommendation applies to both a temporary regulatory framework for permitting gas production projects during rulemaking, and the permanent regulatory framework once rules are promulgated. As a result, the draft statutory language associated with this recommendation does not contain sunset provisions.

Draft statutory language: 93.5175

Rationale
The EQB is recommending that a mandatory Environmental Assessment Worksheet (EAW) be prepared for a gas resource development permit application under the temporary regulatory framework (see EQB Recommendation EQB-1).

Minnesota statutes currently direct a responsible governmental unit (RGU) to assess the proposal of a specific action its reasonable costs for preparing, reviewing, and distributing an environmental impact statement (EIS) (116D.045 Subd. 1.). The RGU cannot start work on the EIS until at least one-half of the assessed cost has been paid, and no permit can be issued by a state agency for the proposer's projects until a final EIS decision is made and the full costs of completing the EIS have been paid.

State agencies have typically borne the costs of EAWs, although there are mechanisms for costs associated with environmental review to be recouped by state agencies for projects that involve new, complex, or controversial projects with certain characteristics. For example, projects that involve large water appropriations and also require environmental review can recoup certain costs associated with that review such as those consistent with Minnesota Statutes 103G.301 Subd2(b). Projects that involve new industries to Minnesota, such as gas exploration, should expect that until the potential impacts are well understood, they will be subject to an increased level of scrutiny requiring collection of new information about the technologies and industry where those costs could be borne by proposers. As projects come forward and the understanding about impacts increases, the challenges of dealing with new issues should decline and thus the need for some measure of cost reimbursement should decline as well. Multiple EAWs can be managed by DNR project managers, so at estimate of 0.3 FTE would be assessed per EAW.

During the public input period, there were concerns expressed over whether the gas resource development industry was being unfairly singled out, given that permit applicants do not pay the costs of EAWs when they are required elsewhere in the state (and, in particular, when they are required for other types of natural resource development, such as mining). The State Legislature limited GTAC's focus to recommendations for permitting gas resource development; review and recommendations on environmental review costs for other industries or activities would therefore be out of scope.

Recommendation DNR-13: Contested case hearing

Recommendation

Procedures set in statute for contested case hearings for nonferrous permits-to-mine should be adapted for challenges to gas resource development permit decisions.

Draft statutory language: 93.5176

Rationale

A landowner who believes that a nonferrous metallic mine project will adversely affect them, or any federal, state, or local government having responsibilities affected by a proposed nonferrous mine project may file a petition with the commissioner to hold a contested case hearing on a completed permit application (93.483). If a petition is granted, disputed aspects of the permit decision can be heard by a neutral administrative law judge, who can then, based on the facts, make a recommendation to the commissioner on whether the permit should be issued (with or without modification) or rejected. The DNR believes, as a matter of consistency, that the same opportunities to dispute facts used to make nonferrous mine permit decisions should be provided for gas resource development permits.

Financial assurance

Recommendation DNR-14: Financial assurance requirements for a gas resources development projects should as a guide, follow similar financial assurance processes for nonferrous metallic mining projects.

Recommendation

The financial assurance requirements for gas resource development projects should largely mirror established statutes and rules for financial assurance of nonferrous metallic mining projects. This recommendation is for both the temporary and regulatory frameworks.

Draft statutory language: 93.5177

Rationale

Minnesota lacks a regulatory framework for requiring financial assurance for gas resource development projects. It does, however, have a robust regulatory framework for financial assurance for other types of mineral resource production, such as nonferrous metallic mine projects (see Mn Statutes 93.44-93.51, Mn Rules Chapter 6132). The DNR believes that new statutes and rules for gas resource development financial assurance in Minnesota should closely follow comparable regulations for mining projects, with modifications as needed to reflect the differences between gas resource development and the mining of solid minerals. This approach provides:

- a degree of uniformity in how natural resource development projects are financially assured;
- statutory language and rules that are familiar to the legislature and Minnesotans; and,
- statutory approach that has been tested in the courts.

The statutes and rules for nonferrous mine projects were established in the absence of active mine projects (as is the case for permitting gas resource development projects) and offer a clearer, robust regulatory framework.

Some might argue that would be inappropriate to apply nonferrous financial assurance rules for gas resource development projects, given the large differences in scope and scale between a large metallic mine project and a gas resource development project that could be as small as one gas well and one gas enrichment plant on one drill pad. This recommendation, however, focusses on the overall structure and scope of the financial assurance processes, and allows for customization that is informed by the differences between mining and gas resource development.

Recommendation DNR-15: Financial assurance requirements should not rely upon corporate guarantees.

Recommendation

The DNR recommends that corporate guarantees not be accepted as a stand-alone financial assurance instrument for gas resource development projects. This recommendation is for both the temporary and regulatory frameworks.

Draft statutory language: 93.5177 Subd. 2

Rationale

Financial assurances are a source of funds to be used by the DNR if the permittee fails to perform:

- Reclamation activities including closure and post-closure maintenance needed if operations cease; and
- Corrective action as required by the DNR if noncompliance with engineering design and operating criteria occurs.

Corporate guarantees are one type of financial assurance instrument that allow a company to rely on its own financial strength to provide assurance that it can and will meet its reclamation obligations. Using this type of instrument requires having the necessary expertise to monitor and evaluate a company's corporate structure assets, liabilities, and net worth to oversee such guarantees.

History shows that some companies are unable to meet corporate guarantee obligations, not having the financial capability to guarantee reclamation performance. Modern financial assurances include reclamation bonds and irrevocable letters of credit (ILOC), trusts and other bank issued financial assurance instruments to address reclamation and corrective action needs. Modern financial assurance instruments such as these are not dischargeable during a bankruptcy. Unlike modern financial assurance instruments, corporate guarantees typically do not allow regulators to access a specific financial asset if the operator cannot meet its reclamation obligations. Additionally, corporate guarantees can require considerable administrative oversight or reliance by third party auditors and are not recommended financial assurance instruments for other types of natural resource developments regulated by the DNR.

While the DNR does not recommend the use of corporate guarantees as a stand-alone financial assurance instrument, they can be useful in providing added layers of corporate accountability to a more comprehensive financial assurance package that includes modern financial assurance instruments as the primary sources of protection.

Recommendation DNR-16: Allow money collected as part of financial assurance for gas resource development permits to be invested by the State Board of Investment.

Recommendation
The DNR recommends that any money collected as part of financial assurance for gas resource development projects be allowed to be invested by the State Board of Investment.

Draft statutory language: 11A.236

Rationale
Under current statute, the State Board of Investment, when requested by the commissioner of natural resources, may invest money collected by the commissioner as part of financial assurance provided under a metallic mineral permit to mine. That money is then allowed to gain investment earnings, rather than sit in a non-interest-bearing account, typically for several years. The DNR recommends that money collected as part of financial assurance for gas resource development projects be similarly allowed to be invested by the SBI, for the same purposes and benefits.

Recommendation DNR-17: Add statutory language for financial assurance under a temporary regulatory framework that sunsets once rules are promulgated.

Recommendation
To support a temporary regulatory framework for permitting gas resource development projects during rulemaking, new statutory language is recommended that would only be in effect until rules are adopted for financial assurance requirements for gas production projects, as required under 93.514.

Draft statutory language: 93.5177 Subd. 3

Rationale
Financial assurance requirements for mining projects in Minnesota are established by statutes and rules. The statutes alone, if adapted for permitting gas resource development projects, would not be sufficient for a temporary regulatory framework. The GTAC recommendations for that temporary regulatory framework can only be taken up by the legislature in statutory language. One way to address this is to take regulatory language that would normally be in rules and place it within a statute that sunsets once rules for financial assurance for gas production projects are promulgated. GTAC's recommended statutory language for financial assurance within the temporary framework (93.5177 Subd. 3) includes a sunsetting subdivision that accomplishes that goal.

Correlative Rights, Pooling, and Spacing Units

Recommendation DNR-18: The correlative rights of the owners of a shared gas resource should be protected.

Recommendation
The DNR recommends that a statutory definition be provided for correlative rights, and that the protection of correlative rights be identified as a compelling state interest within a declaration of state policy and called out when appropriate in statutory language covering pooling and spacing units for gas

resource development projects. This recommendation is for both the temporary and post-rulemaking regulatory frameworks.

Draft statutory language: 93.5151 to 93.5153.

Rationale

"Correlative rights" means that each owner and producer in a common pool or source of supply of gas must have an equal opportunity to obtain and produce the owner's or producer's just and equitable share of the gas underlying the pool or source of supply. This is the antidote to "Rule of Capture" and protects landowner interests. Respect for the correlative rights of all owners of mineral interests within a gas resource development area is cornerstone of establishing spacing units and issuing pooling orders.

Recommendation DNR-19: The DNR commissioner should be given statutory authority to establish or modify spacing units, with each spacing unit including the maximum area that can be efficiently and effectively extracted by an operator's gas well or set of gas wells. The commissioner should also have statutory authority to modify those spacing units when warranted.

Recommendation

The DNR recommends that the DNR commissioner be given statutory authority to establish spacing units, with each spacing unit including the maximum area that can be efficiently and effectively extracted by an operator's gas well or set of gas wells. The commissioner should also have statutory authority to modify those spacing units when warranted. This recommendation is for both the temporary and post-rulemaking regulatory frameworks.

Draft statutory language: 93.5152.

Rationale

While the commissioner of natural resources has rulemaking authority to adopt rules governing the spacing of gas wells to regulate the density of drilling to prevent unnecessary draining of a gas reservoir and to prevent economic waste of products from gas wells (93.514 (a) (4)), there is no statutory authority for the commissioner (or any other entity) to actually establish spacing units that support this goal. The DNR believes that the authority to create or modify spacing units for the development of gas resources should be derived from statute, rather than rule. And since the legislature gave the commissioner of natural resources rulemaking authority over spacing units, it follows that the commissioner also be given the authority to establish or modify spacing units that encompass the maximum area that can be efficiently and effectively developed by an operator's gas well or set of gas wells.

Recommendation DNR-20: The DNR commissioner should have statutory authority to determine the process for establishing operator-proposed spacing units, and to collect an application fee for operator-proposed spacing units.

Recommendation

The DNR recommends that the commissioner of natural resources be given statutory authority to establish a process by which a person can propose the creation of a spacing unit. This authority includes, but is not limited to, identifying application requirements, determining the timing of applications if they are part of a gas resource development permit application, reviewing and approving spacing unit applications, and altering the size or shape of an established spacing unit, as necessary to ensure that a spacing unit closely matches the maximum area that could be drained by the operator's gas well or set of wells. This recommendation is for both the temporary and post-rulemaking regulatory frameworks.

Draft statutory language: 93.5152.

Rationale

This recommendation gives the DNR commissioner statutory authority to create spacing units, describes how an applicant can propose a spacing unit for their wells or set of wells, and identifies the information that needs to be included in that application. It gives the commissioner standards for approving spacing unit applications, and the right to alter the size and shape of an established spacing unit if new information comes to light about the maximum area that could be drained by the operator's gas wells or set of wells. While all of this might be implied should the commissioner be given statutory authority to establish spacing units, the intention of this recommendation is to provide clarity.

Establishing spacing units is prerequisite to issuing pooling orders, and both are required to protect correlative rights of landowners within areas of the state with developable gas resources.

Recommendation DNR-21: Allow landowners to voluntarily pool their mineral interests for the joint development of a shared gas resource.

Recommendation

The DNR recommends that the rights of landowners to voluntarily pool their mineral interests for the joint development of a shared gas resource be recognized in statute. This recommendation is for both the temporary and post-rulemaking regulatory frameworks.

Draft statutory language: 93.5153, Subd. 1.

Rationale

The best way to fully protect the correlative rights of landowners with mineral interests within a spacing unit is to encourage (or, at a minimum, allow) the landowners to voluntarily pool those interests for the joint development of gas resources with that spacing unit. Most gas leases offered to private landowners include provisions that allow the lessee to pool the leased mineral interests with other landowners, without government order or intervention. The DNR also expects to have voluntary pooling provisions within negotiated gas leases issued for state-managed mineral rights.

Recommendation DNR-22: In the absence of voluntary pooling, allow a person that owns or has secured the consent of the owners of at least fifty percent of the mineral interests within a spacing unit to apply to the DNR commissioner for a pooling order that would combine all mineral interests within a spacing unit for the development of gas resources within that unit. In a related action, give the DNR commissioner statutory authority to issue pooling orders, and authority to determine the application process for pooling orders. DNR also recommend that fees for involuntary pooling order applications be set in statute.

Recommendation

The DNR recommends that the commissioner of natural resources be given statutory authority to issue pooling orders that allow for the equitable and efficient development of gas resources while minimizing waste and the drilling of unnecessary wells. A person that owns or has secured the consent of the owners of at least fifty percent of the mineral interests within an established spacing unit should be able to apply for a pooling order that would combine all of the mineral interests within a spacing unit for the development of gas resources within the unit. The DNR also recommendations that the commissioner be given statutory authority to determine the application process for pooling orders and the required components of the application, and that application fees for pooling orders be set in statute. This recommendation is for both the temporary and post-rulemaking regulatory frameworks.

Draft statutory language: 93.5153. Subd. 2. thru Subd. 4.

Rationale

Spacing units established by statute will encompass the maximum area that can be efficiently and effectively developed by an operator's gas well or set of gas wells. If all mineral interests within that spacing unit are owned by the operator, then there is no need to pool the ownership interests within that spacing unit, since there is only one owner. If there is more than one owner of mineral interests within the spacing unit, and if all of the owners agree to jointly develop the gas resources, then there is no need for the state to pool the ownership interests, since they would already be voluntarily pooled. However, if there are owners within the spacing unit that are unwilling to have their equitable share of the gas resource developed, or refuse to jointly develop the identified gas resource, then the state may have a compelling interest to pool the interests of both consenting and nonconsenting owners, subject to the conditions identified by statute. Pooling prevents wasteful and scattered gas resource development and the drilling of unnecessary wells and keeps the decisions of nonconsenting owners from infringing on the right of their consenting neighbors to develop their proportionate share of the gas resource. Pooling orders necessarily protect the correlative interests of nonconsenting owners, who are still provided an equitable share of the profits from gas resource development.

The DNR recommends that a person applying for a pooling order control at least fifty percent of the mineral interests within an established spacing unit, with allowances made for the slight variations in acreage within sectional units and subunits that reflect the curvature of the Earth.

Input received during the public input period included recommendations that the minimum percentage of control required for a pooling order application be set higher. The DNR has reviewed the pooling and spacing regulations in 36 U.S. states with oil and gas resources. Thirty-two of the thirty-six states (89%) do not require a pooling order applicant to own or control any mineral interests within a spacing unit (i.e., the threshold is 0%). There are four states that do an application threshold greater than zero percent (Colorado, Tennessee, Kentucky, and Idaho). These minimum control percentages range from 45% to 55%. The recommended threshold of 50% control for a pooling order in Minnesota would be in the middle of that relatively tight range.

There are six states that don't have a threshold requirement to apply for or request a pooling order, but instead have threshold requirements for approval of a proposed pooling order by those persons who control production rights within a spacing unit and/or persons with a royalty interest within a spacing unit. The DNR believes that it is better to require evidence of controlled ownership interests within a spacing unit (and implied approval) before a pooling order application is accepted, rather than afterwards.

Recommendation DNR-23: To protect the correlative interests of the owners of unleased mineral rights within a spacing unit, processes and procedures must be put in place that allows an owner to challenge a proposed pooling order, and for challenges to be resolved before a pooling order is issued.

Recommendation

The DNR recommends that the rights of the owners of unleased mineral interests within a spacing to challenge a proposed pooling order be protected in statute. Policies and procedures must be put in place by the commissioner to allow for such challenges, and a pooling order should not be issued until a challenge is resolved and a final ordered issued. This recommendation is for both the temporary and post-rulemaking regulatory frameworks.

Draft statutory language: 93.5153. Subd. 2.

Rationale

An applicant for a pooling order must assert that they control at least fifty percent of the mineral interests within a spacing unit. While the state will make a good-faith effort to verify this assertion by reviewing the information provided by an applicant's application, the owners of mineral interests located inside the spacing unit should have the right and opportunity to independently challenge that assertion, and for their challenges to be fairly considered by the commissioner, and resolved before a pooling order is issued.

Recommendation DNR-24: A pooling order application must be resolved before the applicant drills a gas well or wells within the associated spacing unit.

Recommendation

The DNR recommends that a gas well must not be drilled until a pooling order application tied to that gas well has either been rejected or a final pooling order issued. This recommendation is for both the temporary and post-rulemaking regulatory frameworks.

Draft statutory language: 93.5153. Subd. 4.

Rationale

With policies and procedures established that allow the owners of mineral interests within a spacing unit to challenge a pooling order application, it makes sense to require the resolution of those challenges before allowing a gas well or set of wells to be drilled. This is because a successful challenge to the assertion made by the applicant that they control at least half of the mineral interests within a spacing unit would prevent a pooling order from being issued (at least until the operator obtains control of enough additional mineral interests to meet the established threshold). This recommendation would not be relevant if all of the mineral interests owners within a spacing unit have voluntarily agreed to pool their interests, and a pooling order is unnecessary.

Recommendation DNR-25: Statutory language should be adopted that describes how pooled mineral interests are managed during gas development operations, and how the correlative interests of nonconsenting mineral interest owners are protected by ensuring they receive a proportionate share of the profits from a gas resource development project.

Recommendation

The DNR recommends that statutory language should be adopted that describes how pooled mineral interests are managed during gas development operations, and how the correlative interests of nonconsenting mineral interest owners are protected by ensuring they receive a proportionate share of the profits from a gas resource development project. This recommendation is for both the temporary and post-rulemaking regulatory frameworks.

Draft statutory language: 93.5153.

Rationale

Statutory language that sets requirements for the management of pooled mineral interests and describes in sufficient detail the rights and responsibilities of the operator of wells within a spacing unit is needed to protect the correlative interests of both nonconsenting owners of mineral interests within a spacing unit and those landowners who have voluntarily pooled their mineral interests for joint development of a gas resource.

Recommendation DNR-26: A person applying for a pooling order must present evidence to the DNR commissioner that they have made reasonable offers, in good faith, to secure the control of all of the mineral interests within a spacing unit. They must also prove that they provided each owner relevant information about their ownership interests within the pooled area and informed them about the pooling procedures described in these new statutes and their options under these statutes.

Recommendation

The DNR recommends that person applying for a pooling order must present evidence to the DNR commissioner that they have made reasonable offers, in good faith, to lease or secure working interest participation for all mineral interests within a spacing unit. They should also prove that they provided each owner relevant information about their ownership interests within the pooled area and informed them about the pooling procedures described in these new statutes and their options under these statutes. This recommendation is for both the temporary and post-rulemaking regulatory frameworks.

Draft statutory language: 93.5153. Subd. 8.

Rationale

This recommendation protects the correlative interests of landowners within a spacing unit by ensuring that the owners of mineral interests that are not under control of the operator were given a fair and reasonable offer to voluntarily pool their interests by either by accepting a lease offer by that operator or taking a working interest in the project. Landowners who refuse to voluntarily pool their mineral interests should know that their mineral interests could still be included within a state-issued pooling order, understand their rights under that pooling order (including the right to challenge a pooling order application), and realize that they will receive fair compensation for the development of their proportionate share of the pooled gas resource. Requiring the operator to provide a state-created document that explains correlative rights and the pooling order process will ensure that a nonconsenting owner receives the right information and contact information at the DNR if they have any questions.

Recommendation DNR-27: The operator of gas wells under a pooling order should provide monthly statements to nonconsenting owners of all costs incurred, together with the amount of gas produced and the proceeds realized from the sale of production during the previous month.

Recommendation

The DNR recommends that the operator of wells under a pooling order in which there is a nonconsenting owner furnish the nonconsenting owner with a monthly statement of all costs incurred, together with the quantity of gas produced, and the amount of proceeds realized from the sale of production during the preceding month.

Draft statutory language: 93.5153. Subd. 10.

Rationale

This recommendation protects the correlative rights of nonconsenting owners by requiring monthly statements by the operator of wells under a pooling order that provide financial and production data that nonconsenting owners could use to determine whether their rights under a pooling order are being protected. Similar requirements are common with oil and gas lease agreements, and (more generally) leases for the exploration and development of state-managed mineral interests in Minnesota.

Recommendation DNR-28: Unleased mineral interests tied to an American Indian tribe or band owning reservation lands in Minnesota or owned by the federal government should be shielded from pooling orders.

Recommendation

The DNR recommends that the State of Minnesota exclude from a state-issued pooling order unleased mineral interests tied to an American Indian tribe or band owning reservation lands in Minnesota and to a tribal member who owns mineral interests with that tribe's reservation or community. This recommendation is for both the temporary and post-rulemaking regulatory frameworks.

Draft statutory language: 93.5153. Subd. 5.

Rationale

Under federal law, state-issued pooling orders for the development of gas resources do not apply to unleased "Federal or Indian oil and gas." While a state statute that excludes from its pooling orders unleased American Indian tribe or band owned reservation lands in Minnesota might seem redundant, DNR believes there is a place for this acknowledgement of sovereign rights within state statute, as well as excluding from pooling orders any unleased mineral interests owned by a tribal member within the boundaries of a tribal reservation or community. The recommended application of this proposed statutory language to "American Indian tribe or band owning reservation lands" is based on the statutory language in 93.52, Subd. 2.

We note that this recommendation is only for unleased reservation lands. Tribes are free to lease their mineral interests (including oil and gas rights) to operators seeking to develop gas resources, and operators who are applying for a pooling order for a spacing unit that includes Tribal lands must obtain a lease from the Tribes.

Gas Development on Forfeited Severed Mineral Interests

Recommendation DNR-29: Set in statute that commercial extraction of gas resources is prohibited on forfeited severed mineral interests.

Recommendation

The DNR recommends that existing statutory language for forfeited severed mineral interests be amended to say that neither mining nor extraction of gas or other mineral resources can occur on forfeited severed mineral interests until a court determines the forfeiture of those mineral interests to be absolute. This recommendation is for both the temporary and post-rulemaking regulatory frameworks.

Draft statutory language: 93.55 Subd. 2

Rationale

Under current statute, the DNR is allowed to lease forfeited severed mineral interests for mineral exploration and development, but the lessee is barred from mining on those mineral interests until a court determines the forfeiture of those mineral interests to be absolute. While gas resources such as helium or hydrogen are tied to the mineral estate, these gases are not "mined;" instead, gas resources are commonly describes as being "produced" or "extracted" from the subsurface. Amending this statute to say that, "A lessee holding a lease issued under this subdivision may not mine <u>or extract gas or other mineral resources</u> under the lease until the commissioner completes the procedures…" clarifies that neither mining solid minerals nor extracting gas resources is allowed on forfeited severed mineral interests until the commissioner of natural resources completes a legal process and, "…a court has adjudged the forfeiture of the mineral interest to be absolute."

Recommendation DNR-30: $xxx annually to the DNR starting in FY26, as provided under Minnesota Statute Chapter 93 for mineral resource management including permitting activities associated with gas resource development.

Recommendation

The DNR recommends $xxx annually to the DNR starting in FY26, as provided under Minnesota Statute Chapter 93 for mineral resource management including permitting activities associated with gas resource development.

Rationale

As provided under Minnesota Statute Chapter 93 and among other mineral resource management activities, DNR needs to hire staff who will start and manage a gas exploration and production permitting program in the state.

Minnesota Department of Health

Agency background

Minnesota Statutes, chapter 103I, authorizes the Commissioner of Health to license persons wanting to explore or prospect for natural gas, receive exploratory borings notifications, and regulate the construction of temporary sealing, and permanent sealing of exploratory borings. Minnesota Rules, chapter 4727, provides requirements under the described authorization for the regulation of exploratory borings and persons conducting regulated work. The Minnesota Department of Health (MDH or Department) collects applicable fees for the described work, which supports the inspection of exploratory borings and the protection of public health and groundwater.

February of 2024, a licensed explorer submitted an exploratory boring notification to MDH under the requirements of Minnesota Statutes, chapter 103I, and Minnesota Rules, chapter 4727, communicating the boring was for exploring and prospecting for helium gas. Minnesota Rules, chapter 4727, has no provisions for production of gas from an exploratory boring, nor for the construction of a gas well for production of gas. It is the Department's understanding that boreholes drilled and cased by the gas development industry are not typically for exploration or prospecting but also for gas production. Currently, Minnesota Statutes, chapter 103I, define that exploratory borings are for exploration and prospecting and not for production of gas.

As a direction of the 2024 Minnesota Legislature, MDH became a member of the Minnesota Gas and Oil Technical Advisory Committee (GTAC) because of the Department's regulatory authority over exploration of natural gas and was provided expansive authority for oversight of exploratory boring construction to Minnesota Rules, chapter 4727.

The following recommendations outline the requirements necessary to ensure the safe construction and sealing of gas wells providing protection of public health and groundwater. Included in these recommendations is creating a new rule chapter to regulate gas wells. Most of the recommended requirements are like those in effect for other types of regulated wells and borings.

Recommendation MDH-1: Modify the exploratory boring definition and create requirements for exploratory borings that encounter gas.

Recommendation
Modify the exploratory boring definition within Minnesota Statutes, section 103I.005, subdivision 9 and create requirements under Minnesota Statutes, section 103I.601, to protect public health and groundwater for exploratory borings that encounter gas.

Draft statutory language: Minnesota Statutes, section 103I.005, subdivision 9; Minnesota Statutes, section 103I.601.

Rationale
Referring to 'gas' as 'natural' in the exploratory boring definition in Minnesota Statutes, section 103I.005 is ambiguous; thus, modifying the exploratory boring definition to refer only to 'gas' and creating a statutory definition for 'gas' which includes "both hydrocarbon and nonhydrocarbon gases" adds clarity.

Existing exploratory boring requirements do not address situations where gas is encountered during drilling and construction. GTAC solicited feedback from a variety of people and organizations. From this feedback, GTAC learned of the interest to continue exploring for gas resources with exploratory borings, as currently allowed by law. MDH modified initial recommendations, which prohibited gas exploration with exploratory borings, to allow for gas resource exploration using exploratory borings. Requirements were added to these recommendations to protect public health and groundwater. These recommendations prohibit extraction and production of gas from exploratory borings and require permanent sealing. Extracting and producing gas would require permitting through the Department of Natural Resources, environmental review, and the construction of a gas well.

MDH recommends the removal of 'oil' from the exploratory boring definition because there are no indications of crude oil resources in the state, and MDH is not aware of any industry interest in drilling for oil in Minnesota. If crude oil resources are discovered, or there is future interest in oil exploration in the state, the statutes and rules for gas production could be amended to include oil.

Recommendation MDH-2: Repeal Commissioner of Health's existing authority to regulate exploring and prospecting for natural gas and oil; **and authorize the Commissioner to make rules and establish fees for the regulation of gas wells.**

Recommendation

Repeal Commissioner of Health's existing authority under Minnesota Statutes, section 93.514, paragraph a, clause 2, to amend or adopt rules on exploration and prospecting for natural gas and oil; and authorize the Commissioner to make rules and establish fees for the regulation of gas wells.

Draft statutory language: Minnesota Statutes, section 93.514, paragraph a, clause 2; Minnesota Statutes, section 103I.706, subdivision 1; Minnesota Statutes, section 103I.706, subdivision 2.

Rationale

Minnesota Statutes, section 93.514, paragraph a, clause 2, provides duplicative authority to regulate exploration for gas. MDH has existing authority under Minnesota Statutes, section 103I.101 to adopt rules and regulate exploration of gas with exploratory borings. However, this existing authority does not authorize the regulation of gas well construction and sealing. Currently, no agency in the State has authority to regulate gas wells.

Other states regulating the extraction and production of gas generally use the term "well" rather than "boring". Exploratory borings, defined under Minnesota Statutes, section 103I.005, subdivision 9, does not authorize the extraction or mining of materials and minerals from the subsurface. Thus, extracting and producing gas from an exploratory boring is prohibited under current statute.

The GTAC authority to submit a recommendation to the legislature (Laws of Minnesota 2024, chapter 116, article 3, section 55) on boring monitoring and inspection is proposed to be repealed. MDH recommends using new rulemaking authority to regulate the construction and sealing of gas wells, including inspections.

MDH recommends new rulemaking and fee authority to clarify and provide comprehensive regulation for the construction and sealing of gas wells. Creating a new rule chapter specifically to address the exploration and extraction of gas via gas wells will allow for distinction between the regulation of gas wells and wells accessing groundwater. Current rulemaking authority for wells and borings under Minnesota Statutes, chapter 103I, do not provide for the construction and sealing of gas wells, nor the extraction of gas from a well.

Recommendation MDH-3: Modify the well definition and add a definition for gas well.

Recommendation

Modify the well definition within Minnesota Statutes, section 103I.005, subdivision 21, to specify that gas wells are not wells accessing groundwater; and add a definition for gas well to Minnesota Statutes, section 103I.005, subdivision 10b.

Draft statutory language: Minnesota Statutes, section 103I.005, subdivision 21; Minnesota Statutes, section 103I.005, subdivision 10b.

Rationale

MDH recommends clarifying the exemption in the “well” definition (Minnesota Statutes, section 103I.005, subdivision 21) that a well does not include an excavation made to obtain or prospect for gas. This clarifies the current definition of “well” to refer only to a well accessing groundwater. A new definition for a “gas well” would be created to specifically define a well used for the purposes of locating, extracting, and producing gas. Adding a definition for a “gas well” would add clarity around: a “gas well” is for locating, extracting, and producing gas; a “well” is for accessing groundwater; and an “exploratory boring” is for exploring and prospecting for gas and minerals.

Recommendation MDH-4: Ensure a person or company has a license issued by the Commissioner of Health to conduct regulated work on gas wells.

Recommendation

Ensure a person or company has a license issued by the Commissioner of Health to conduct regulated work on gas wells including construction and sealing.

Draft statutory language: Minnesota Statutes, section 103I.706, subdivision 4.

Rationale

MDH’s existing authority regulates the licensing and certification of persons constructing and sealing wells and borings, but not gas wells. MDH is recommending to model licensure and certification requirements for regulated work on gas wells after existing rule requirements. A person constructing or sealing gas wells would be licensed and certified under existing regulation. Ensuring a licensed and certified person conducts regulated work on gas wells is protective of public health and groundwater.

Recommendation MDH-5: A person must submit a gas well construction notification and fee for each proposed gas well.

Recommendation

A person must submit a gas well construction notification and fee for each proposed gas well to the Commissioner of Health. A gas well construction notification and fee cannot be submitted to the Commissioner of Health until the person has a valid a gas resource development permit from the commissioner of natural resources.

Draft statutory language: Minnesota Statutes, section 103I.706, subdivision 2; Minnesota Statutes, section 103I.707, subdivision 3; Minnesota Statutes, section 103I.706, subdivision 5.

Rationale

Prior to a person beginning to drill a gas well, the person must obtain a gas resource development permit from the Commissioner of Natural Resources and must submit a well construction notification to the Commissioner of Health. This allows for Department of Natural Resources review of the gas development project, including environmental review, and provides a mechanism for MDH to be informed of the intent to construct the proposed gas well. The gas well construction notification allows for the Department to plan for and inspect gas well construction to ensure compliance and the protection of public health and groundwater. The construction notification fee will financially support the processing of the received notifications and inspections of gas wells. The proposed gas well notification is like existing notification requirements in Minnesota Rules, chapter 4725, for other well construction.

Recommendation MDH-6: A person must grant the commissioner of health access to a gas well site to inspect.

Recommendation

A person must grant the Commissioner of health access to a gas well site to inspect the constructing and sealing of a gas well.

Draft statutory language: Minnesota Statutes, section 103I.706, subdivision 6.

Rationale

MDH has authority to enter a site to inspect a gas well, including the construction and sealing of gas wells. The Department must be able to enter gas well sites and inspect gas wells to ensure compliance with Minnesota Statutes to protect public health and groundwater.

Recommendation MDH-7: A person must notify Commissioners of Health, Natural Resources and the Pollution Control Agency of an occurrence during a construction or sealing of a gas well that has a potential for significant adverse public health or environmental effect.

Recommendation

A person must notify Commissioners of Health, Natural Resources, and the Pollution Control Agency of an occurrence during a construction or sealing of a gas well that has a potential for significant adverse public health or environmental effect.

Draft statutory language: Minnesota Statutes, section 103I.706, subdivision 7.

Rationale

The Minnesota Department of Health, Minnesota Department of Natural Resources, and Minnesota Pollution Control Agency must be made aware of situations that have potential to significantly affect public health or the environment. Upon notification of a situation, these agencies will provide information about required mitigation actions to protect public health and the environment.

Recommendation MDH-8: A person must not use a gas well to inject or dispose surface water, groundwater, or any other liquid, gas, or chemical.

Recommendation
A person must not use a gas well to inject or dispose surface water, groundwater, or any other liquid, gas, or chemical. MDH is recommending that this does not prohibit the injection of approved drilling fluids and allows for injection and disposal under a Class 2 injection well[2] permit, authorized by the Environmental Protection Agency (EPA).

Draft statutory language: Minnesota Statutes, section 103I.707, subdivision 4.

Rationale
The injection or disposal of liquids, gases, and chemicals may cause significant contamination to groundwater and risk to public health. Injection or disposal increases the likelihood of introducing contaminants to a drinking water source, adversely impacting water quality and public health. The prohibition on injection or disposal of unapproved liquids, gases, or chemicals is consistent with existing requirements in Minnesota Rules, chapters 4725 and 4727.

Recommendation MDH-9: A person is prohibited from hydraulic fracturing a gas well.

Draft statutory language: Minnesota Statutes, section 103I.707, subdivision 5.

Rationale
Helium gas currently being pursued in Minnesota has been identified in the same geologic formation used for supplying drinking water. Hydraulic fracturing a gas well could connect fractures in the gas well with fractures supplying water to drinking water wells.

Recommendation MDH-10: A person must ensure that drilling fluids, cuttings, treatment chemicals, and discharge water are disposed of according to federal, state, and local requirements.

Recommendation
A person must ensure that drilling fluids, cuttings, treatment chemicals, and discharge water are containerized and disposed of off-site according to federal, state, and local requirements. However, an approved Class 2 injection well permit, authorized by the EPA, may be used.

Draft statutory language: Minnesota Statutes, section 103I.707, subdivision 6.

Rationale
Improper collection and disposal of drilling fluid, cuttings, treatment chemicals, and discharge water could contaminate soil, groundwater, and surface water. These materials and fluids may contain contaminants that may adversely impact public health or the environment.

Recommendation MDH-11: Drilling fluids used during the construction of a gas well must be water or air based and additives must meet the requirements of ANSI/NSF standard 60.

Recommendation
Drilling fluids used during the construction of a gas well must be water or air based and additives must meet the requirements of ANSI/NSF standard 60.

[2] https://www.epa.gov/uic/class-ii-oil-and-gas-related-injection-wells

Draft statutory language: Minnesota Statutes, section 103I.707, subdivision 7.

Rationale

Drilling fluids allowed for other wells and borings regulated by MDH under Minnesota Statutes, chapter 103I, and Minnesota Rules, chapters 4725 and 4727, must be potable water with a free chlorine residual or air. Any drilling fluid additives must meet the requirements of American National Standard Institute (ANSI)/National Sanitary Foundation (NSF) standard 60. ANSI/NSF standard 60 establishes the minimum health-effects requirements for chemicals added to drinking and includes well drilling additives. Limiting drilling fluid additives to ANSI/NSF standard 60 approved products reduces the threat to public health and groundwater.

Recommendation MDH-12: A person must meet gas well casing and grout requirements.

Recommendation

A person must meet gas well casing and grout requirements to ensure protection of groundwater from surface contaminants entering the well and spread of contaminants across multiple aquifers.

Draft statutory language: Minnesota Statutes, section 103I.707, subdivision 8.

Rationale

A person must ensure a gas well is constructed in a manner to protect public health and groundwater. Proper installation of casing and grout materials protects against interconnecting aquifers or allow surface contaminants to enter the well. This requirement is consistent with existing requirements in Minnesota Rules, chapters 4725 and 4727, which protect against contaminants entering a well or spread across multiple aquifers.

Recommendation MDH-13: A person must meet gas well isolation distances.

Recommendation

A person must meet isolation distances to provide physical separation of a gas well for the protection of public health and groundwater.

Draft statutory language: Minnesota Statutes, section 103I.707, subdivision 9.

Rationale

MDH is recommending physical separation of a gas well from residential buildings, water supply wells, schools, and childcare centers to provide the necessary time to identify and mitigate a potential contamination event. Providing physical separation of a gas well from nearby people and water supply wells protects against potential adverse effects to public health and groundwater.

Recommendation MDH-14: A person must protect groundwater during the construction and sealing of a gas well.

Recommendation

A person must protect groundwater during the construction and sealing of a gas well. A gas well must not be constructed to interconnect aquifers or allow surface contaminants to enter the well.

Draft statutory language: Minnesota Statutes, section 103I.707, subdivision 10.

Rationale

During construction of a gas well surface contaminants must be excluded from the well and interconnection of aquifers is prohibited. If surface materials or fluids are allowed to enter the well during construction activities, contaminants may distribute into and through the groundwater. Interconnected aquifers may allow for contamination to spread and increase the risk to public health or the environment.

Recommendation MDH-15: A person must permanently seal a gas well and an exploratory boring that has encountered gas to prevent contamination of groundwater and the environment.

Recommendation

A person must permanently seal a gas well and an exploratory boring that has encountered gas to prevent contamination of groundwater and escape of gas to the environment.

Draft statutory language: Minnesota Statutes, section 103I.707, subdivision 11; Minnesota Statutes, section 103I.601.

Rationale

Proper permanently sealing of a gas well and an exploratory boring that has encountered gas is needed to ensure contaminants do not enter groundwater through the well or boring, which may be a drinking water source. MDH recommends permanent sealing of an exploratory boring when the boring has encountered gas during construction and gas has not dissipated prior to sealing. Permanent sealing ensures protection of public health, groundwater, and the environment.

Recommendation MDH-16: A person must submit a permanent sealing notification and fee for each gas well and exploratory boring that encounter gas.

Recommendation

A person must submit a permanent sealing notification and fee for each gas well prior to sealing each gas well. A permanent sealing notification and fee are also required for exploratory borings that encounter gas if gas has not dissipated prior to sealing.

Draft statutory language (Appendix A): Minnesota Statutes, section 103I.706, subdivision 8; Minnesota Statutes, section 103I.706, subdivision 2; Minnesota Statutes, section 103I.707, subdivision 11; Minnesota Statutes, section 103I.601, subdivision 10, paragraph b.

Rationale

Prior to a person beginning to permanently seal a gas well or an exploratory boring encountering gas the Department must be informed of the intent to seal. This allows for the Department to plan for and inspect gas well and exploratory boring sealing to ensure compliance and the protection of public health and groundwater. The sealing notification fee will financially support the processing of the received notification and inspection of gas wells and exploratory boring that encounter gas. The proposed permanent sealing notifications are like existing notification requirements in law for well sealing.

Recommendation MDH-17: MDH is requesting an appropriation to develop a gas well construction and sealing notification program.

Recommendation

MDH is requesting an appropriation to develop a gas well construction and sealing notification program.

Draft statutory language (Appendix A): Section 1

Rationale

The MDH Well Management Section (Section) will not be able to implement a new program and rule chapter to develop a Gas Well Program unless there is funding to support hiring staff knowledgeable in the gas well industry. In addition, there is no agency in Minnesota that has oversight over sealing and construction of gas wells. Currently, staff within the Section are subject matter experts in water wells and borings, and exploratory borings, to protect public health and groundwater, and not experts in extraction of a natural resource, construction engineering or sealing of a gas well. The Section will need help from consultants within the gas industry and staff with the technical expertise of constructing and sealing of gas wells to successfully implement this new authority. Additionally, the program is already under resourced with completing the required actions for oversight of constructing and sealing of water supply wells and other activities such as inspections and license approvals for the existing program. The Section is solely a fee-based program and is seeking an appropriation to support this new authority and oversight to develop and maintain this program. Without an appropriation, the Section will need to increase the costs to proposed fees to support the recommendations and statutory requirements.

Minnesota Environmental Quality Board

Agency and Program background

A key component of the regulatory framework for gas production projects – whether temporary or permanent - is the need to define when a project is subject to mandatory environmental review.

The function of Minnesota's Environmental Review Program is to provide information about future projects to avoid and minimize damage to Minnesota's environmental resources. The program accomplishes this by requiring certain proposed projects to undergo review, following defined procedures, prior to obtaining needed approvals and permits. Environmental review provides an opportunity for both the public and decision makers to understand the potential for significant environmental effects from a project prior to the project moving forward.

The Minnesota Environmental Policy Act establishes Minnesota's environmental review program, which requires environmental review for any project that has or may have the potential for significant environmental effects.

The Environmental Quality Board, as administrator of the Environmental Review program, identifies in rule certain project types for which environmental review is mandatory. These rules are referred to as the mandatory category rules and define a threshold for when projects of the listed type may or will have the potential for significant environmental effects. If a project is one listed within the mandatory categories and meets or exceed the thresholds defined by the rules, then environmental review is required.

The mandatory categories can require completion of one of two different processes of review. The Environmental Assessment Worksheet (EAW) process is used to review a project that *may* have the potential for significant environmental effects. An Environmental Impact Statement (EIS) is the process for reviewing a project that does have the potential for significant environmental effects. The EIS has increased requirements for the level of information provided and analyzed as well as the amount of interaction required with the public. For example, an EIS must include evaluation of alternative scenarios of the proposed project in order to explore methods of reducing adverse environmental effects. Mandatory category thresholds are usually based on project size; EAW thresholds typically align with a smaller size project while an EIS is triggered by a larger project.

A project that meets a mandatory category threshold for an EAW *may* have the potential for significant environmental effects; it is the role of the environmental review process to identify if the project does have the potential for significant effects or if mitigation efforts and regulatory requirements can allow the project to occur without that potential. If the EAW process identifies that the project does have the potential for significant environmental effects, then the project review proceeds to the EIS process to further analyze the effects from the project compared to potential alternatives.

The rules assign a unit of government – the Responsible Governmental Unit (RGU) – to conduct the review, following standardized public processes to disclose information about environmental effects and ways to minimize and avoid them.

Recommendation EQB-1: Require a mandatory environmental assessment worksheet (EAW) for any gas resource development project. The DNR will serve as the responsible governmental unit (RGU).

Draft statutory language: 116D.04 Subd. 16a. (a)

Rationale

Establishing a new mandatory category or requirement for environmental review necessitates understanding the potential for significant environmental effects from a project; defining what size of project and at what phase of development needs review; and identifying an RGU to complete the review.

Potential for significant environmental effects:

EQB staff believe that for the temporary regulatory framework it is appropriate to require an EAW for all gas development projects, recognizing that any projects of this type *may* have the potential for significant environmental effects. A gas development project may have the potential for significant environmental effects relating to air quality, land use, transportation, noise, and water quality.

Gas production and extraction projects are new in Minnesota, and there is still work to be done to understand the full type and extent of possible environmental impacts, along with their likelihood. Requiring a mandatory EAW recognizes that at least some of these types of projects are likely to affect the environmental in some ways and allows opportunities for governmental units to learn about potential impacts from these projects.

Some input received from Tribal governments and the public suggested that all gas resource development projects need an EIS to properly evaluate their impacts. In the framework of Minnesota's environmental review program, requiring an EIS for all projects would indicate that all gas resource development projects affirmatively have the potential for significant environmental effects. EQB does not yet have the information to make this decision. Similarly, project developers provided input indicating that they do not feel that an EAW is necessary because of the small footprint of gas projects. Not requiring an EAW for all projects would indicate that at least some gas resource development projects clearly do not have the potential for significant environmental effects. EQB also does not have sufficient information to make this decision.

With current information, EQB believes that any gas resource development project may have the potential for significant environmental effects. The EAW process is used to review those projects that *may* have the potential for significant environmental effects and to determine if that potential does exist; if so, the review proceeds to the EIS process. The purpose of the EAW is to decide if an EIS is required. The mandatory EAW process allows the RGU to determine on a project-by-project basis if the nature and location of those projects require further analysis of environmental effects through an EIS.

Any EAWs completed during the temporary framework will also contribute to EQB's future determination (through rulemaking) of the size and scope of projects that have or may have the potential for significant environmental effects and the creation of permanent mandatory categories for these types of projects.

Timing for environmental review and defining of gas projects:

The mandatory category rules are written to ensure that a project proposer and responsible governmental unit understand what project action triggers environmental review. Construction, expansion, and development are common terms used within the rules to define the need for environmental review at a certain project phase.

The environmental review process needs to ensure that the impacts from a gas project can be properly evaluated prior to permitting, making the timing of the review and its tie to the triggering event important. For many mining or extractive projects, typically exploratory boring is completed to evaluate the subsurface extent of the natural resource that is intended to be extracted. In those cases, the initial exploration may not require environmental review; instead, review may not be required until a more complete mining project plan is needed. In these cases, the environmental impacts are tied much more to the overall project development rather than the initial exploration.

However, gas extraction projects have an opportunity to work differently. The drilling of even an "exploratory" well for gas extraction is likely to result in a permanent location, from which the project developer will likely proceed to extract and produce gas (if any gas is found). Environmental review is required to provide information regarding potential environmental effects from all proposed aspects of a project that may impact the environment. It is important to ensure that the required environmental review (an EAW) adequately encompasses a project as a whole.

Converting an exploratory boring into a production well creates a connection from the exploration phase to the production phase, so it is impractical to distinguish between the two. In this scenario, there is a single project which requires environmental review to analyze both the exploration and production prior to the initial (exploratory) action. Therefore, converting an exploratory boring (which has not been through environmental review) to a production well greatly limits the analysis that can take place and understanding of potential environmental effects from a gas resource development project. EQB does not believe this supports effective environmental review. Therefore, the initial draft recommendation was that an EAW should be done prior to exploration, assuming that wells would generally be converted from exploratory to production.

Through the public input period GTAC members have heard that there is a need for exploratory actions to take place in order to define a production project. The initial recommendations called for environmental review and permitting to be completed prior to any exploration; therefore, all phases of the project would be evaluated through the environmental review process. In response to the input received, MDH has proposed to include exploration for gas resources in their program for construction and sealing of exploratory borings. Under MDH rules, exploratory borings require notifications but not permits. In conjunction, the recommendations include a prohibition on the use of an exploration well for production purposes and requires sealing of exploration wells.

With this change, the act of exploring for gas for the purposes of gaining information in order to properly define a project is allowed to follow the existing exploratory framework for wells without first requiring environmental review. The requirements of constructing and sealing exploratory borings would not be subject to the EAW requirement. The regulatory framework for drilling wells (or exploratory borings) in Minnesota does not require a permit or government approval prior to drilling the well, and therefore does not meet the definition of a "project" within the scope of the environmental review rules. This does not preclude this type of information from being included in environmental review if a project is pursuing a gas resource development permit with a conceptual approach.

A mandatory EAW would still be required prior to the issuance of a gas resource development permit, but the permit will no longer be required for exploratory borings. Because of the prohibition of production from an exploratory boring as well as the sealing requirements, the EAW would still provide opportunities for effective analysis of and mitigation measures for environmental effects for gas resource development projects which may need to consider cumulative potential effects from exploration activities.

DNR currently has requirements for reclamation of exploratory borings on state land, however there is no requirement for privately owned lands. This could become an issue if project proposers over develop sites that are being utilized for exploration with the intent to convert the area to a production area. Care should be taken when permitting land use development for exploration sites to ensure project proposers are not segmenting projects into smaller pieces in order to avoid environmental review. The requirement for reclamation of exploratory borings on state land would mitigate these potential issues but only on state land; most local units of government do not have policies requiring reclamation of exploration sites on private land.

Gas production is new to Minnesota. Completing an environmental review can be extremely beneficial for a new project type; new project types are likely to raise a lot of questions, and the environmental review process informs the public and decision-makers about a project's potential environmental impact prior to permitting.

Additionally, requiring an EAW for any gas project as a part of the interim temporary framework allows the EQB and permitting agencies to gather information about potential environmental effects, supporting future work to further develop a mandatory category in rule that includes a scientifically supported size threshold for the type of projects expected to take place in Minnesota.

While EQB staff are not recommending a mandatory EIS threshold for a gas project at this time, the RGU maintains the responsibility to evaluate and decide whether any project going through the EAW process does have the potential for significant environmental effects and will require an EIS.

Responsible Governmental Unit:

The final component of a framework for environmental review is determining who should serve as the Responsible Governmental Unit. EQB recommends that the Department of Natural Resources serve as the Responsible Governmental Unit. The DNR is the appropriate choice for serving as the RGU as they have the greatest responsibility for supervising or approving the project as a whole and the greatest expertise as an RGU in reviewing these project types.

Recommendation EQB-2: Require all environmental review notices for gas resource development projects to include tribal contacts.

Draft statutory language: 116D.04 Subd. 16a. (b)

Rationale

Tribal governments have expressed the need to be included in the environmental review process for gas resource development projects and to have coordination and consultation with reviewing and permitting agencies. EQB has, in the FY25 organizational workplan, identified the need to update our guidance to provide best practices that support RGUs in considering Tribal resources. We envision this will likely include best practices for communicating environmental review information with Tribes. EQB's rules set forth distribution lists for sharing environmental review documents; these lists include the Minnesota Indian Affairs Council, but do not otherwise mention Tribal governments.[3] Based on the Tribal feedback, the EQB has added this recommendation that would require any EAW publication and notification for a gas resource development project also include Minnesota Tribal governments as defined in Minn. Stat. 10.65. Minn. Stat. 10.65 also identifies the need for certain state agencies to coordinate and consult with Minnesota Tribal governments. EQB does not have the authority to define when agencies must consult with Tribal governments but believes this requirement will support communication and information sharing with Tribal governments and their inclusion in the environmental review process for gas resource development projects.

Recommendation EQB-3: The RGU for gas resource development projects should work collaboratively with all units of government for which a project undergoing environmental review will ultimately be subject to regulation.

Draft statutory language: NA

Rationale

Input received from the public and from Tribal governments indicate a desire for the MPCA to serve as the RGU rather than the DNR. EQB's recommendations for the DNR to serve as the RGU align with existing rules and longstanding practice on how RGUs are chosen. The EQB recognizes the "gas resource development permit" being proposed by the DNR as the action which constitutes the supervision or approval of a gas extraction/production project as a whole. A gas resource development permit is intended to encompass all the activities on site under one overarching permit. Other agencies, such as the MPCA, may need to issue multiple permits for individual actions within the overall gas production project - but a higher number of these permits does not constitute a greater supervision over the project as a whole. There are similarities with other project types where the MPCA issues permits for individual actions of a project such as commercial and some industrial uses as well as metallic and non-metallic mineral mining, but the RGU is designated as either the local unit of government or the DNR. These designations of RGU's in those types of projects are supported by the fact that the permit for which those units of government are responsible is representative of the overarching permit which constitutes the supervision of a project as a whole.

However, as noted by the input received from the public and Tribal governments, the MPCA will potentially need to issue numerous regulatory permits for a gas resource development project. It is not uncommon for a project undergoing environmental review to need multiple permits from multiple authorities. The EQB finds it useful to emphasize the need for collaborative work within environmental review as a recommendation within this report. It has been noted throughout this report that gas extraction and production is a new project type in Minnesota and governmental units can benefit from the environmental review process in order to learn about potential environmental effects from this project type. The recommendation suggests that the RGU incorporate all governmental units that may have regulation over a gas resource development project within the environmental review process to ensure that all environmental effects can be properly understood and to inform those future decisions

[3] Separately from this recommendation, EQB has identified the need to review and potentially update rules around EAW and EIS distribution.

and permits that fall outside of the RGU's responsibility. This recommendation does not include statutory language as the rules of environmental review are already in place to allow for collaborative work to inform decision makers and the public regarding potential environmental effects from projects.

Minnesota Pollution Control Agency

Agency background

The Minnesota Pollution Control Agency (MPCA) plays a unique role in state government. The MPCA monitors environmental quality, offers technical and financial assistance and enforces environmental regulations. The MPCA finds and cleans up spills or leaks that can affect our health and environment. The MPCA also develops statewide policy, supports environmental education and helps ensure pollution does not have a disproportionate impact on any group of citizens. The MPCA plays a key role in the statewide outcome of "a clean, healthy environment with sustainable uses of natural resources."

Further, the MPCA issues permits with the goal of limiting pollution and protecting human health. MPCA monitors the conditions of air, land, groundwater, and surface water at more than 2,320 sites. MPCA also inspects and licenses more than 40,000 sites that involve hazardous waste, feedlots, and storage tanks.

As noted throughout this report, gas production is the focus of this writeup. Helium gas production has not previously been regulated at the MPCA. The media and regulations under MPCA's authority that are pertinent to this industry include, but are not limited to: water quality permits: wastewater, industrial stormwater, and construction stormwater; air quality permitting, storage tank regulation; and solid waste. Environmental review is an information gathering tool that can help inform regulatory processes. Therefore, recommendations that MPCA makes for temporary and permanent regulations are as follows:

Recommendation MPCA-1: Minnesota currently has rule and regulations in place to regulate the proposed gas production industry. Following established rules and regulations will protect the environment and human health. Furthermore, the MPCA will comply with Minnesota Statute Section 10.65 which requires timely and meaningful consultation between the state and tribal governments on matters under MPCA's authority that may have Tribal implications.

Rationale

Water Quality:

Stormwater

Construction Stormwater: Any project proposer that plans to disturb more than one acre of land needs to apply for a Construction Stormwater National Pollutant Discharge Elimination System/State Disposal System (NPDES/SDS) permit. If your project is under an acre in size, but is part of a larger common plan of development, you will also need a permit. More information on CSW permits can be found on MPCA's website here: https://www.pca.state.mn.us/business-with-us/construction-stormwater

Industrial Stormwater: Facilities in specific industries that store materials, waste, or equipment outdoors are subject to industrial stormwater regulations administered by the MPCA. These facilities must take steps to monitor and manage stormwater on their properties where stormwater may come into contact with harmful pollutants including toxic metals, oil, grease, de-icing salts, and other chemicals. Industrial stormwater permittees in Minnesota are regulated by a general permit that is reissued every five years. A project proposer would need to apply for an Industrial Stormwater (ISW) general NPDES/SDS permit for any activity as required under the permit. More information can be found on the MPCA ISW webpage at: https://www.pca.state.mn.us/business-with-us/industrial-stormwater

Wastewater

Any waste and wastewater resulting from gas well production including, but not limited to: surface water, groundwater, or any other liquid, gas, or chemical must be in accordance with Minnesota Department of Health's statutory gas well language at Minn. R. 4725.2050 administered by Minnesota Department of Health. This does not prohibit the injection of approved drilling fluids as provided in Subd. 9 for drilling and development of a gas well.

Options for disposal of wastewater associated with a gas well include:

Class 2 Injection well. Class 2 injection wells are currently permitted and regulated under the U.S. Environmental Protection Agency (EPA). Minnesota does not have Class 2 injection well primacy so any permit would need to be obtained through U.S. EPA. More information can be obtained here: https://www.epa.gov/uic/class-ii-oil-and-gas-related-injection-wells

A project proposer can contain and dispose of any wastewater at an authorized wastewater treatment facility (WWTF) willing to accept the waste.

A project proposer can apply for an individual NPDES/SDS permit to treat and surface discharge any wastewater. As currently understood, Effluent Limit Guidelines 40 CFR 435 do not apply to this industry. Therefore, an individual NPDES/SDS permit developed with best professional judgement (BPJ) and water quality based effluent limits (WQBELs) is appropriate.

Air Quality:

If there is equipment for on-site electricity generation (e.g., diesel generator), internal combustion engine requirements in state (Minn. R. 7011.2300) and federal rules (40 CFR 60 Subpart IIII or JJJJ; 40 CFR 63, Subpart ZZZZ) would likely apply and an air permit would likely be required. While it does not appear that federal standards and guidelines for crude oil and natural gas facilities (40 CFR Subpart OOOO) would apply, an official EPA applicability determination has not been made. If any of these federal requirements would apply, an air permit would likely be required. The exact state and federal standards and permitting requirements cannot be determined without having site-specific information on all the equipment, how the facility will be operated, and all potential air emissions.

Currently, there are no known regulatory gaps in current rules that would prohibit or impair the MPCA's ability to issue a permit to helium or hydrogen extraction project that is required to obtain an air quality permit. It is important to note that Minnesota currently does not have rules that regulate the release of greenhouse gases (e.g., CO_2 and CH_4) that may be released during helium or hydrogen extraction. Given that the well gas contains the greenhouse gases methane and carbon dioxide (CO_2) (approximately 2.5% and 68%, respectively), Minnesota should consider regulating those gases to eliminate or minimize their release to the atmosphere and ensure the state is taking actions to meet the statutory greenhouse gas reduction goals for the state. The most effective option to eliminate or minimize greenhouse gas emissions from helium or hydrogen extraction is through carbon capture and sequestration or carbon capture and beneficial use. Where that is not feasible, converting the methane to CO_2 through flaring may be the next best option. Flaring, sometimes used in managing landfill gases, would also provide the benefit of reducing or eliminating non-methane hydrocarbons, air toxics, and odor causing compounds that may be found at lower concentrations in the well gas and that would otherwise be released to the atmosphere.

Aboveground Storage Tanks (AST)

The MPCA's AST rules as written do not allow the MPCA to regulate gases stored in tanks in a permit; MPCA's permits as currently written would not be applicable to storage of gases due to the nature of gases. The MPCA's AST program was setup as a water (i.e., surface and groundwater) protection program from inception. This is the same for the small AST program and major facility AST program (i.e., cumulative capacity of one million gallons or more).

The rules that govern the scope and procedures for "major facility substance storage permits" (note: this is the specific rule name for MPCA AST permits) are in:

> Minn. R. 7001.0020.H, which is the rule that says MPCA permits are subject to the general MPCA permit procedures in 7001.0010 to .0210 (this applies to all media, for example, air, water, hazardous waste, etc. permits), unless otherwise specified, and
>
> Minn. R. 7001.4200 to .4250, which has the scope and procedures specific to AST permits.

Further, substances which are inherently a gas like helium or hydrogen are not subject to AST permits, per 7001.4205.4 which says, "Substance means any liquid material which is not gaseous or solid at ambient temperature and pressure...". The reason that gases are excluded from this rule is because AST permits regulate "liquids only" and is reiterated by Minn. R. 7001.4201; the purpose is to protect against entry of stored substances into waters of the state (i.e., groundwater and surface water). In regards to a gas, if it were to escape a tank, it would enter the air but would not enter any water of the state.

In summary, if there are ASTs at either type of operation, exploration or production, which do not add up to one million gallons, a permit is not required, but the tanks are still regulated by Minn Chapter 7151 rules for small ASTs. Therefore, the existing AST rules, as written and intended, will cover AST storage for this type of operation adequately, but regulating the storage of gases is exempt and outside of current AST rule scope. Should regulation of gases be desired, new rules would have to be written. Lastly, this industry must comply with all applicable Mine Safety and Health Administration (MSHA) and United States Environmental Protection Agency (U.S. EPA) standards, and any other existing rules and regulations regarding ASTs.

Solid Waste

Currently as understood, no solid waste permits would be required as this is not an industrial activity that treats, transfers, stores, processes, or disposes of solid waste. However, it is always the responsibility of the project proposer to: review rules and regulations to evaluate whether a permit is needed, to apply for the appropriate permit(s), and to implement Industrial Solid Waste Management Plans (ISWMPs). Further, a guidance document on water filter backwash solids has criteria for the disposal level criteria for radium. Should there be a need to dispose of solid waste that has radium contained in, the acceptable radium disposal limit is in this guidance.

Moving forward, the MPCA could consider adding a rule disposal restriction related to radium levels for any waste generated from the gas industry in the section that lists the industrial waste types that must be addressed in the Industrial Solid Waste Management Plans (ISWMPs) in Minn. R. 7035.2535, subp. 5. The disposal level restriction would then have to be included in the facility's ISWMP if they accept waste from it. However, it is GTAC's current understanding that radioactive gases and materials associated with this industry are not expected to be at levels that would necessitate this.

Recommendation MPCA-2: Avoid use of products containing per- and polyfluoroalkyl substances, also known as PFAS.

Rationale

Minnesota is protecting human health and the environment by reducing the use of PFAS. In Minnesota, PFAS are prohibited in food packaging and firefighting foam, with some exceptions, as of 2024. In January 2025, a comprehensive PFAS pollution prevention law called Amara's Law begins to take effect when 11 categories of consumer products sold or distributed in Minnesota must be made without PFAS. Reporting requirements on remaining PFAS use begins in 2026. By 2032, nonessential use of PFAS in products will be prohibited.

Minnesota Department of Revenue

Agency background

The Department of Revenue is a named participant on GTAC and is tasked with developing recommendations on the taxation of gas and oil extraction, including helium. Minnesota Statutes already contain tax administration laws covering the assessment of taxes for taconite, other iron bearing materials, and non-ferrous minerals but do not contain provisions for taxing gas or oil extracted in the state.

Two common types of taxes are collected on mining in Minnesota and nationally:

- A severance tax for removing the natural resource from the earth; and
- An income tax on the business of mining

In Minnesota, the severance tax for non-ferrous minerals is known as the Gross Proceeds Tax and the income tax for all mining is known as the Occupation Tax.

The scope of recommendations on taxation includes incorporating gas and oil into existing mining tax laws, aligning the exemptions for the newly created gas and oil provisions with exemptions in place for existing mining businesses, and improving tax administration for taxpayers and Revenue. Rulemaking is not included in the scope of these recommendations because Revenue believes the draft statutory language is sufficient on its own. Revenue has rulemaking authority under Minnesota Statutes, section 270C.06, should it be determined rules are needed later.

Recommendation DOR-1: Incorporate gas and oil into existing Occupation Tax.

Recommendation

The Occupation Tax currently applies to all mining companies in the state of Minnesota. New statute definitions were created, and existing statute definitions were modified to incorporate gas and oil in the Occupation Tax law.

Draft statutory language

289A.02, subdivision 6; 298.001, subdivision 3a; section 298.001, subdivision 10a; section 298.001, subdivision 14; section 298.001; subdivision 15; section 298.001, subdivision 16; 298.01, subdivision 3; 298.01, subdivision 3a; 298.01, subdivision 3b; 298.01, subdivision 4a; 298.01, subdivision 4b section 298.17

Rationale

Revenue reviewed statutes from 10 states and found that each state had some equivalent of an income tax structure in place for mining companies extracting and processing gases in their state. Revenue determined that using our existing Occupation Tax, which is in place of the Corporate Income Tax for mining companies in Minnesota, would both:

- Promote consistent application of the Occupation Tax across all types of mining companies in Minnesota; and
- Align with other states in applying a form of income tax on gas producers.

Recommendation DOR-2: Incorporate gas and oil into existing Gross Proceeds Tax.

Recommendation

The Gross Proceeds Tax applies to all mining companies that mine non-ferrous minerals, such as copper or nickel, in the state of Minnesota. New statute definitions were created, and existing statutes were modified to incorporate gas and oil in the Gross Proceeds Tax law.

Draft statutory language

289A.02, subdivision 6; 298.001, subdivision 3a; section 298.001, subdivision 10a; section 298.001, subdivision 14; section 298.001; subdivision 15; section 298.001, subdivision 16; 298.015, subdivision1; 298.016 subdivision 1; 298.016, subdivision 2; 298.016, subdivision 3 298.016, subdivision 4; 298.016, subdivision 4a

Rationale

Revenue reviewed statutes from 10 states and found that each state had some equivalent of a severance tax structure in place for mining companies extracting and processing gases in their state. Revenue determined that using our existing Gross Proceeds Tax, which is a form of severance tax on resources extracted from our state, would both:

- Promote consistent application of the Gross Proceeds Tax across all types of mining companies in Minnesota; and
- Align with other states in applying a form of severance tax on gas producers.

Recommendation DOR-3: Modify the Gross Proceeds Tax rate section to allow different tax rates for different gases, minerals, and oils.

Currently, non-ferrous mining companies are subject to a Gross Proceeds Tax equal to 0.4% of the gross proceeds from mining in Minnesota. Current statutes are modified to allow the Legislature to set different tax rates for copper, nickel, other non-ferrous minerals, oils, and different types of gases, including helium, carbon dioxide, and hydrogen. No specific new tax rates have been included in this draft.

Draft statutory language

298.015, subdivision 1

Rationale

Incorporating different tax rates for the non-ferrous minerals, gases, and oil would provide comparable effective tax rates to be applied across the board. This will provide a uniform tax structure among the different types of gases, minerals, and oils to ensure a fair and consistent tax rate.

Revenue reviewed severance tax rates in 10 other states and found the tax rates for gas and oil ranging from about 2% to 9% in those states. However, in many states, certain deductions are allowed under the severance tax. In addition, the estimated effective tax rate for the taconite Production Tax, the comparable severance tax for the long-established iron ore and taconite industry in Minnesota, is about

2.8%. (This percentage was calculated as an estimated rate for the Production Tax and was estimated based on mine value that Revenue computes each year.)

One additional issue to note: Revenue's recommendation that the Legislature consider establishing a different Gross Proceeds Tax rate for each individual gas differs from what is seen nationally. In all the states that Revenue reviewed, a single severance tax rate (or in some states, one progressive range of rates), is established for all gases. Other states also have a similar structure for oil, with a single severance tax rate (or one progressive range of rates) established for all forms of oil extracted in each state.

As noted above, our recommendation is that the Legislature consider setting a separate rate for each type of gas. This would allow consideration of the different costs of processing extracted resources into marketable quality when setting the tax rate for each gas.

The table below highlights the range of severance tax rates for gas in 10 states.

State	Tax Rate for Gas	Tax Base and Deductions Allowed
Arizona	3.125% of computed tax base Ariz. Stat. § 42-5010(A)(3)	"Tax base" is the gross proceeds of sales or gross income derived from the business and includes the value of the entire product. Ariz. Stat. § 42-5072 A deduction is allowed for freight paid from the place of production to place of delivery. Ariz. Stat. § 42-5072
Colorado	2% to 5% on gross income from sales (rate increases as gross income increases) C.R.S.A § 39-29-105	"Gross income" is the net amount realized for the sale of gas. A sale can occur at a wellhead or after transportation, manufacturing, and processing. C.R.S.A § 39-29-102(3)(a) Deductions are allowed for direct costs of transportation, manufacturing, and processing. Depreciation can also be deducted. C.R.S.A § 39-29-102(3)(a)
Kansas	8% of gross value K.S.A. § 79-4217(a)	"Gross value" is the sale price of gas when it is removed from the lease or production unit. K.S.A. § 79-4216(d)
Michigan	5% of gross cash market value of the total production of gas M.C.L.A. § 205.303(3)	The value of all production is calculated at the wellhead but does not include severance tax reimbursements paid by a pipeline company, common carrier, or common purchaser. M.C.L.A. § 205.303(3) Deductions include the exempt cubic feet attributed to the State of Michigan, the United States, or a political subdivision of Michigan or the United States.

State	Tax Rate for Gas	Tax Base and Deductions Allowed
		M.C.L.A. § 205.303(3)
Montana	For Primary Recovery Production of a working interest in a post-1999 well past the first 12 months of production, 9.3% of gross taxable value of natural gas; during the first 12-month period, .8%. M.C.A. § 15-36-304; Oil and Natural Gas Production Tax Article, Montana Natural Resources – Tax Examiner 1-2-25	Total gross value is the total cubic feet produced, multiplied by average wellhead value per cubic foot. Inert gases, including helium, are included in Montana's definition of "natural gas." M.C.A. § 15-36-305 Producers can deduct oil or gas used in operating the well. M.C.A. § 15-36-305
New Mexico	3.75% of taxable value N.M.S.A. § 7-29-4	"Taxable value" is the value of products (liquid hydrocarbons removed from natural gas, carbon dioxide, helium, non-hydrocarbon gases, and natural gas) minus deductions. N.M.S.A. § 7-29-4.1 Deductions include royalties paid to the United States, New Mexico, Indian Tribes, Indian pueblos, or Indians that are wards of the United States. Reasonable expenses for trucking products to the first place of market can also be deducted. N.M.S.A. § 7-29-4.1
Oklahoma	7% on the gross value of production 68 OK. Stat. § 1001(B)	A "gross value" is the gross proceeds realized from the first sale of such production, including the actual cash value and all premiums otherwise given to, or reserved for, the producer and all interest owners of such production, without any deduction for costs whatsoever. 68 OK. Stat. § 1001(B),(J); Oklahoma Tax Commission, Gross Production Monthly Tax Report, Form 341, Instruction 11. Producers of natural gas and casinghead gas may deduct marketing costs that enable the transport of gas to market. 68 OK. Stat. § 1001.4
Texas	7.5% of the market value Tex. Tax Code Ann. § 201.052	"market value" is the value at the production well. Tex. Tax Code Ann. § 201.101 A deduction is allowed for actual marketing costs.

State	Tax Rate for Gas	Tax Base and Deductions Allowed
		Tex. Tax Code Ann. § 201.101
Utah	For natural gas, 3% to 5% of the taxable value (rate increases as value increases) Utah Code § 59-5-102(4) For natural gas liquids, 4% of the taxable value Utah Code § 59-5-102(4)	"Taxable value" is the total value of the gas minus royalties paid to interest holders and total value of exempt gas. Utah Code § 59-5-102(1) Deductions possibly include processing and transportation costs, including those for gas that is exempt from tax. Utah Code § 59-5-103.1
Wyoming	6% on the value of the gross product extracted W.S. § 39-14-212(f); W.S. § 39-14-204	Helium is valued as natural gas and at its fair market value after production is complete. W.S. § 39-14-212(b); W.S. § 39-14-203(b) Production for natural gas is complete after extracting, gathering, separating, injecting, and other activities which occur before the outlet of the initial dehydrator. If no dehydration occurs, production is complete at the inlet to the initial transportation related compressor, custody transfer meter, or processing facility, whichever occurs first. W.S. § 39-14-212(d); W.S. § 39-14-203(b)(4)

Recommendation DOR- 4: Require Gross Proceeds Taxpayers to Provide Sales Information by the Normal May 1 Filing Date Each Year.

Statutory language is being proposed to require mining companies subject to the Gross Proceeds Tax to file an informational report by May 1 following the close of the calendar year.

Draft Statutory Language

289A.12, subdivision 19; 289A.19, subdivision 2

Rationale

Revenue generated by the Gross Proceeds Tax is distributed to different parties under current Minnesota Statutes, section 298.018. Currently, Minnesota law requires Gross Proceeds taxpayers to file an annual return by May 1 following the close of the calendar year. Taxpayers are granted an automatic seven-month extension, making the extended due date December 1. Distributions related to Gross Proceeds revenue must be made just 15 days later on December 15.

This short timeframe does not allow Revenue sufficient time to verify the reported sales or revenue totals before the distribution date. Requiring the informational report, which would be due on the normal return due date of May 1, would allow Revenue adequate time to complete this verification process before making the required distributions.

Recommendation DOR-5: Apply the same exemptions and exclusions for gas and oil producers that exist for other mining businesses.

Current law provides certain exemptions and exclusions applicable to mining companies subject to the Gross Proceeds Tax and Occupation Tax. These exemptions and exclusions should be modified to include any oil and gas producers that become subject to these taxes.

Statutory language

272.02, subdivision 97; 272.03, subdivision 1; 273.12; 290.0134, subdivision 9; 290.0135; 290.05, subdivision 1; 290.923, subdivision 1; 297A.68, subdivision 5; 297A.71, subdivision 14; 298.01, subdivision 5; section 298.01, subdivision 6;

Rationale

All mining companies that are subject to Minnesota's Occupation Tax or Gross Proceeds Tax should be treated equitably regardless of what they mine, including oil and gas. Oil and gas would be added to existing exclusions and exemptions for mining companies. These exclusions and exemptions include:

- Income exclusions for Corporate Franchise Tax;
- Updated royalty withholding requirements on gas and oil royalty payments;
- Property Tax exemptions for real and personal property at the site where the mining or production occurs; and
- Sales and Use Tax exemptions that apply to equipment purchased for gas and oil extraction and construction of new mines or processing plants.

Recommendation DOR-6: Legislature should establish distribution model for gas and oil.

Current law establishes one method for distributing the proceeds from the Occupation Tax on non-ferrous metals and minerals and another method for distributing the proceeds from the Gross Proceeds Tax on such metals and minerals. The Legislature could decide to follow those existing methods for the distribution of the taxes on gas and oil. Alternatively, the Legislature could choose to create different distribution methods for gas and oil tax proceeds. The recommendations exclude gas and oil proceeds from following the established distribution methods and create two new subdivisions with blank distribution placeholders. This allows the Legislature to determine how proceeds from the taxes on gas and oil should be distributed in the state.

Draft statutory language

298.018; 298.17; 298.018

Rationale

Distribution of tax proceeds is a policy decision. This recommendation allows policymakers to establish a distribution method they deem appropriate for proceeds from taxes on gas and oil.

Statutory Language

Minnesota Department of Natural Resources

Section 1. Section 11A.236 is amended as follows:

ACCOUNT TO INVEST FINANCIAL ASSURANCE MONEY FROM PERMITS TO MINE <u>AND GAS RESOURCE DEVELOPMENT PERMITS</u>.

Subdivision 1. **Establishment; appropriation.** (a) The State Board of Investment, when requested by the commissioner of natural resources, may invest money collected by the commissioner as part of financial assurance provided under a permit to mine <u>or gas resource development permit</u> issued under chapter 93. The State Board of Investment may establish one or more accounts into which money may be deposited for the purposes of this section, subject to the policies and procedures of the State Board of Investment. Use of any money in the account is restricted to the financial assurance purposes identified in sections 93.46 to 93.51<u>8</u> and rules adopted thereunder and as authorized under any trust fund agreements or other conditions established under a permit to mine <u>or gas resource development permit</u>.

(b) Money in an account established under paragraph (a) is appropriated to the commissioner of natural resources for the purposes for which the account is established under this section.

Subd. 2. **Account maintenance and investment.** (a) The commissioner of natural resources may deposit money in the appropriate account and may withdraw money from the appropriate account for the financial assurance purposes identified in sections 93.46 to 93.51<u>8</u> and rules adopted thereunder and as authorized under any trust fund agreements or other conditions established under the permit to mine<u> or gas resource development permit</u> for which the financial assurance is provided, subject to the policies and procedures of the State Board of Investment.

(b) Investment strategies related to an account established under this section must be determined jointly by the commissioner of natural resources and the executive director of the State Board of Investment. The authorized investments for an account are the investments authorized under section 11A.24 that are made available for investment by the State Board of Investment.

(c) Investment transactions must be at a time and in a manner determined by the executive director of the State Board of Investment. Decisions to withdraw money from the account must be determined by the commissioner of natural resources, subject to the policies and procedures of the State Board of Investment. Investment earnings must be credited to the appropriate account for financial assurance under the identified permit to mine.

(d) The commissioner of natural resources may terminate an account at any time, so long as the termination is in accordance with applicable statutes, rules, trust fund agreements, or other conditions established under the permit to mine or gas resource development permit, subject to the policies and procedures of the State Board of Investment.

Section 2. Section 86A.05, subdivision 6 (c) is amended as follows:

(c) State wilderness areas shall be administered by the commissioner of natural resources in a manner which is consistent with the purposes of this subdivision, and shall be managed only to the extent necessary to control fire, insects, and disease, and to preserve existing wilderness or reestablish wilderness conditions. There shall be no development of public roads, permanent dwellings, or recreational facilities except trails for nonmotorized traffic. Motorized traffic shall not be allowed. No commercial utilization of timber or minerals shall be allowed, except for gas resources that are commercially developed without disturbing the surface. Facilities existing at the time of establishment shall be removed.

Section 3. 93.5121 DECLARATION OF POLICY

It is the policy of the state to provide for the beneficial and orderly development of the state's gas resources through laws and policies that prevent waste, avoid the drilling of unnecessary wells, protect correlative rights, and provide for the reclamation of gas resource development locations in a manner that controls adverse environmental effects.

Section 4. 93.5122 DEFINITIONS

Subd. 1. **Applicability.** The definitions in this section apply to 93.5122 through 93.5180

Subd. 2. **Exploration and Production Waste**. Exploration and production waste shall mean those wastes associated with operations to locate or remove gas resources from the ground or to remove impurities from such substances and which are uniquely associated with and intrinsic to gas exploration, development, or production operations that are exempt from regulation under Subtitle C of the Resource Conservation and Recovery Act, 42 USC Sections 6921, et seq. For gas projects, primary field operations include those production-related activities at or near the wellhead and at the gas plant (regardless of whether or not the gas plant is at or near the wellhead), but prior to transport of the gas from the gas plant to market.

Subd. 3 **Gas.** "Gas" includes both hydrocarbon and nonhydrocarbon gases.

Subd. 4 **Gas well.** "Gas well" shall mean a gas well, as defined in Minnesota Statutes, section 103I.005, subd. 10b that is sited at a gas resource development location.

Subd. 5. **Gas resource development facility.** "Gas resource development facility" means equipment or improvements used or installed at a gas development location for the exploration, production, withdrawal, treatment, or processing of gas resources.

Subd. 6. **Gas resource development location.** "Gas resource development location" shall mean a definable area where an operator has disturbed or intends to disturb the land surface in order to locate a gas development facility.

Subd. 7. **Gas resource development operations.** "Gas resource development operations" means exploring for gas by the drilling of exploratory borings; siting, drilling, deepening, recompleting, reworking, or abandoning a gas well; producing operations related to any gas well, including installing flowlines; the generating, transporting, storing, treating, or disposing of exploration and production wastes; and any constructing, site preparing, or reclaiming activities associated with such operations.

Section 5. Section 93.513 is amended to read:

Subdivision 1. **Permit required.** Except as provided in section 103I.681, a person must not engage in or carry out production of gas or oil from consolidated or unconsolidated formations in the state unless the person has first obtained a gas resource development permit for the production of gas or oil from the commissioner of natural resources.

Any permit under this section must be protective of natural resources and must not be issued until the requirements identified in 93.5151 through 93.5153 are met. ~~require a demonstration of control of the extraction area through ownership, lease, or agreement~~. For purposes of this section, "gas" includes both hydrocarbon and nonhydrocarbon gases. For purposes of this section, "production" includes extraction and beneficiation of gas or oil.

Subd. 2. **Moratorium.** Until rules are adopted under section 93.514, the commissioner may not grant a permit for the production of gas or oil unless the legislature approves a temporary permit framework that allows issuance of ~~temporary~~ permits.

Section 6. Section 93.514 is amended to read:

(a) The following agencies may adopt rules governing gas and oil exploration or production, as applicable:

(2) ~~the commissioner of health may adopt or amend rules on groundwater and surface water protection, exploratory boring construction, drilling registration and licensure, and inspections as they pertain to the exploration and appraisal of gas and oil resources;~~

(4) the commissioner of natural resources must adopt or amend rules pertaining to ~~the conversion of an exploratory boring to a production well,~~ pooling, spacing, unitization, ~~well abandonment,~~ siting, financial assurance, ~~and~~ reclamation, and leasing state mineral interests for the production of gas and oil; and

Section 7. 93.5151 DECLARATION OF POLICY

In recognition of the need to prevent or to assist in preventing waste, to avoid the drilling of unnecessary wells, and to protect correlative rights, it is hereby declared to be the policy of this state to provide for the orderly development of this state's gas resources through the establishment of spacing units that regulate the density of drilling, pooling units that combine tracts and mineral interests, and rules for the unitization of gas reservoirs.

Section 8. 93.5152 DEFINITIONS.

Subdivision 1. **Applicability.** For purposes of sections 93.5151 to 93.5179, the terms defined in this section have the meanings given to them.

Subd.2. **Department.** "Department" means the Department of Natural Resources.

Subd. 3. **Commissioner.** "Commissioner" means the commissioner of natural resources.

Subd. 4. **Correlative rights.** "Correlative rights" means each owner and producer in a common pool or source of supply of gas resources must have an equal opportunity to obtain and produce the owner's or producer's just and equitable share of the gas resources underlying the pool or source of supply.

Subd. 5. **Spacing unit.** "Spacing unit" means lands allocated by the commissioner of natural resources to a single gas well, or multiple gas wells, for the development of gas resources under a spacing order.

Subd. 6. **Spacing order.** "Spacing order" means the act by the commissioner of natural resources of allocating lands to a spacing unit.

Subd. 7. **Operator.** "Operator" means any owner or lessee of gas rights engaged in or preparing to engage in gas resource development operations.

Subd. 8. **Notice.** "Notice" means publication in the *State Register*, the *EQB Monitor*, Department of Natural Resources website, and a qualified newspaper that has its known office of issue in the county seat in which the lands at issue are located. If no qualified newspaper has its known office of issue in the county seat of a particular county, then notice must be published in the qualified newspaper designated as the publisher of the official proceedings of the county board of that county. Notice shall be published at least once in the above publications at least 60 days prior to a public meeting, and no more than 180 days prior to a public meeting. The notice shall contain information as the commissioner of natural resources may direct.

Section 9. 93.5152 SPACING UNIT

Subd. 1. **Spacing unit.** An operator must propose to the commissioner a new spacing unit for each gas well or set of gas wells that it plans to drill at a gas resource development location. A spacing unit must include the maximum area that can be efficiently and effectively drained by the operator's well or set of wells. The minimum area of a proposed spacing unit is a quarter-quarter section of land.

Subd. 2. **Spacing unit application.** An application for a spacing unit under this section must be submitted by an operator to the commissioner of natural resources. An operator must submit with the application a certified check, cashier's check, or bank money order payable to the Department of Natural Resources in the sum of $100 as a fee for filing the application. The application fee must not be refunded under any circumstances. The right is reserved to the state to reject any or all applications for a spacing unit. The commissioner must prescribe the information to be included in a spacing unit application.

a) Until such time rules are promulgated by the commissioner regarding spacing, a spacing unit application must include, but not be limited to, the following:

(i) For at least one portion of a mineral tract within the proposed unit, documentation showing the applicant's status as an owner or lessee within the unit. Acceptable forms of documentation include, but are not limited to:

1. Mineral deed;

2. Mineral lease or memorandum of lease; or

3. Any other agreement confirming the applicant's right to drill into and produce from a pool, or a memorandum of such agreement.

4. For federal minerals, certification that the applicant will comply with any applicable federal unit agreement or communitization agreement requirements.

(ii) Certification that the operations in the spacing unit will be conducted in a reasonable manner to protect and minimize adverse impacts to public health, safety, welfare, the environment, and wildlife resources.

(iii) The unit boundary and, if proposing more than one well within a spacing unit, the setback distances between each well.

(iv) Geologic and operational data used by the operator to establish the boundaries of a spacing unit.

(v) The total number of wells within the proposed unit.

(vi) The Gas Resource Development Locations that are proposed for the unit.

(vii) Identification of the associated gas resource development permit application. If the proposed spacing unit and drilling operations are tied to an existing gas resource development plan, the operator should identify both the approved plan and associated application for a permit amendment.

Subd. 3. **Establishment of a spacing unit.** (a) After notice and a public meeting in the county where the proposed unit is located, the commissioner has the authority to establish spacing units by issuing a spacing order. Proposed spacing units may be modified as to size or shape by the commissioner.

(b) Until such time rules are promulgated by the commissioner regarding spacing, in determining whether to approve, approve with modifications, or deny a proposed spacing unit, the commissioner will consider whether the proposed spacing unit:

(i) Prevents waste of gas resources;

(ii) Avoids the drilling of unnecessary wells; and

(iii) Protects correlative rights.

Subd. 4. **Modification of established spacing units.** (a) Spacing units established under a spacing order issued by the commissioner may be modified by the commissioner, upon application. The size of the established spacing unit may be decreased or increased or additional wells permitted to be drilled within the established unit in order to prevent or assist in preventing waste or to avoid the drilling of unnecessary wells, or to protect correlative rights.

(b) An application to modify an established spacing unit may be filed with the commissioner by the operator or an interested party.

Subd. 5. **Temporary exploratory spacing units.** If the commissioner is unable to determine, based on information presented at the public meeting, the existence of a pool and the appropriate acreage to be included within a spacing unit and the shape thereof, the commissioner is authorized to establish exploratory spacing units for the purpose of obtaining evidence as to the existence of a pool and the appropriate size and shape of the spacing unit to be applied thereto. In establishing the size and shape of the exploratory spacing unit, the commissioner may consider, but is not limited to, the size and shape of spacing units previously established by the commissioner for the same gas-bearing rock units in other areas of the same geologic rock formation.

Subd. 6. **Appeals.** Spacing orders issued by the commissioner may be appealed pursuant to section 93.50.

Section 10. 93.5153 POOLING

Subd. 1. Voluntary pooling. When two or more separately owned tracts, including any state-owned tracts, are embraced within a spacing unit, or when there are separately owned interests in all or a part of the spacing unit, then persons owning the interests may pool their interests for the development and operation of the spacing unit.

Subd. 2. Involuntary pooling. In the absence of voluntary pooling, the commissioner, upon the application of a person that owns or leases at least fifty percent of the mineral interests to be pooled, may issue an order pooling all interests in the spacing unit, including those interests of nonconsenting owners, for the development and operation of the spacing unit.

A draft pooling order shall be made after notice and a public meeting in the county where the pooling area is located and must be upon terms and conditions that protect all owners' correlative rights and that afford to the owner of each tract or interest in the spacing unit the opportunity to recover or receive, without unnecessary expense, a just and equitable share. The goal of pooling order is to allow for the equitable and efficient development of gas resources while minimizing waste and the drilling of unnecessary wells.

The commissioner must serve a copy of a draft order by certified mail on all of the owners listed in the affidavit provided under subdivision 3. The applicant, any party served with the order, or any other party with a mineral ownership interest within the spacing unit may demand a contested case hearing within 30 days of the date of mailing. The contested case hearing must be conducted pursuant to chapter 14. Following the contested case hearing, the commissioner will issue a final order.

Subd. 3. Pooling order application. (a) An application for a pooling order under this section must be submitted by an operator to the commissioner of natural resources. An operator must submit with the application a certified check, cashier's check, or bank money order payable to the Department of Natural Resources in the sum of $100 as a fee for filing the application. The application fee must not be refunded under any circumstances. The right is reserved to the state to reject any or all applications for a pooling order. The commissioner must prescribe the information to be included in a pooling order application.

(b) An application for a pooling order submitted to the commissioner must include the following:

(i) Proof that the applicant controls at least fifty percent of the mineral interests to be pooled;
(ii) Map showing location of ownership interests within spacing unit;
(iii) Identification of mineral interests within the spacing unit that are not owned or leased by the applicant. Applicant must include the location and name and address of the owner for all such interests;
(iv) Affidavit by the applicant that it made a good faith effort to lease these other mineral interests within the spacing unit. The affidavit must contain information as to any lease offer made to a mineral interest owner, or efforts to contact a mineral interest owner.

Subd. 4. Drilling and extraction prohibited prior to pooling order issued. On and after January 1, 2025, if a spacing unit contains the mineral interests of any unleased mineral interest owner that has rejected an offer to lease, an operator shall not drill or extract gas resources from the spacing unit before a pooling order is entered by the commissioner.

Subd. 5. Lands excluded from pooling order. Notwithstanding any provision in this section to the contrary, the commissioner shall not enter a pooling order that pools the mineral interests of an unleased mineral interest owner if that owner is:

(a) the federal government; or

(b) an American Indian tribe or band; or

(c) a tribal member and the land is located within that tribe's reservation or community.

If a pooling order application proposes to pool mineral interests described in this subdivision, the commissioner shall deny the application, unless the applicant amends the application to no longer request the pooling of the unleased mineral interests described in this subdivision.

Nothing in this subdivision affects, limits, or expands the federal government's or an American Indian tribe or band's authority to lease, refuse to lease, voluntarily pool, or otherwise dispose of their unleased mineral interests.

Subd. 6. Pooling orders. (a) Upon any portion of a spacing unit covered by a pooling order, all operations incident to well drilling will be deemed to be the conduct of operations upon each separately-owned tract by the several owners of each separately-owned tract. Any portion of production allocated or applicable to each tract included in a unit covered by a pooling order will be deemed to have been produced from the tract by a well drilled upon it.

(b) Each pooling order must:

(i) provide for the drilling of one or more wells (if not already drilled) within the spacing unit in such a manner as to prevent waste;

(ii) provide for the payment of the reasonable actual cost of the wells, including drilling and operating the wells, and a reasonable charge for supervision and storage;

(iii) provide for the proportionate share of the costs and risk of drilling and operating wells for each owner, including each nonconsenting owner;

(A) Except as provided in subdivision 7 of this section, as to each nonconsenting owner who refuses to bear a proportionate share of the costs and risks of drilling and operating the wells, the pooling order must provide for reimbursement to consenting owners to be paid out of, and only out of, production from the unit representing the owner's interest;

(B) Such reimbursement shall exclude any royalty or other interest not obligated to pay any part of the costs of drilling and operating the wells if, and to the extent that, the royalty is consistent with the lease terms prevailing in the area and is not designed to avoid the recovery of costs provided for in subdivision 6(c) of this section;

(C) In the event of any dispute as to the allocation of any costs of drilling and operating the wells, the commissioner will determine the allocation of costs as specified in subdivision 6(c) of this section;

(iv) determine the interest of each owner in the spacing unit and provide that each consenting owner is entitled to receive a share of the production from the wells applicable to the owner's interest in the wells, subject to royalty or similar obligations;

(v) provide that each consenting owner is entitled to receive a proportionate part of any nonconsenting owner's share of the production until costs are recovered;

(vi) provide that each nonconsenting owner is entitled to own and receive that share of the production applicable to the nonconsenting owner's interest in the spacing unit after all consenting owners have recovered the nonconsenting owner's share of the costs out of production;

(vii) specify that any nonconsenting owner is immune from liability for costs arising from spills, releases, damage, or injury resulting from gas resource development operations on the spacing unit, to the extent that such liability is not the fault of the nonconsenting owner; and

(viii) prohibit operators from using the surface owned by a nonconsenting owner without express permission from the nonconsenting owner.

(c)The commissioner, must determine proper costs recoverable by the consenting owners of a spacing unit from the nonconsenting owner's share of production from such a unit, as follows:

(i) One hundred percent of the nonconsenting owner's share of the cost of surface equipment beyond the wellhead connections, including stock tanks, separators, treaters, pumping equipment, and piping, plus one hundred percent of the nonconsenting owner's share of the cost of operation of the well or wells commencing with first production and continuing until the consenting owners have recovered such costs. Any nonconsenting owner's share of these costs of equipment and operation will be that interest that would have been chargeable to the nonconsenting owner had the owner initially agreed to pay the owner's share of the costs of the well or wells from the beginning of the operation.

(ii) Two hundred percent of that portion of the costs and expenses of permitting, environmental review, surveying, well site preparation, obtaining rights-of-way, rigging up, drilling, reworking, deepening or plugging back, testing, and completing the well, after deducting any cash contributions received by the consenting owners, and two hundred percent of that portion of the cost of equipment in the well, including the wellhead connections.

Subd. 7. Costs and royalties for nonconsenting owners. Any nonconsenting owner of a tract within a spacing unit that is not subject to any lease or other contract for gas development is entitled to a landowner's proportionate royalty of eighteen and three-quarters percent until the consenting owners recover the costs specified in subdivision 6(c) of this section. Until costs are recovered, the remaining eighty-one and one-quarter percent of the nonconsenting owner's proportionate share will be allocated to reimburse costs to the consenting owners, as described in subdivision 6(b)(iii).

Following recovery of costs, the nonconsenting owner will be deemed to own his or her full proportionate share of the wells, surface facilities, and production and will then be liable for any further costs as if the nonconsenting owner had been a consenting owner.

Subd. 8. Good-faith effort of lease offer to nonconsenting owners. The commissioner shall not enter an order pooling an unleased, nonconsenting mineral owner under this section over the protest of such owner unless the commissioner has received evidence that the unleased mineral owner has been:

(1) tendered, no less than sixty days before the hearing, a reasonable offer, made in good faith, to participate and pay their proportionate share of costs or to lease upon terms no less favorable than those currently prevailing in the area at the time application for the order is made; and
(2) furnished, in writing, the owner's share of the estimated drilling and completion cost of the gas wells, the location and objective depth of the gas wells, and the estimated spud date for the gas wells or range of time within which spudding is to occur.

The offer to participate or lease must include a copy of or link to a brochure supplied by the commissioner that clearly and concisely describes the pooling procedures specified in this section and the mineral owner's options pursuant to those procedures.

Subd. 9. Disputes between owners and operators. During the period of cost recovery provided under this section, the commissioner lacks jurisdiction to determine the reasonableness of costs of operation of the wells attributable to the interest of the nonconsenting owner. Any owners, consenting or nonconsenting, may file actions in district court, against the operator(s) or each other, challenging the reasonableness of costs. The commissioner also lacks jurisdiction to resolve disputes among owners or operators regarding the ownership of mineral interests contained within spacing units.

Subd. 10. Duty of operator to nonconsenting owners. The operator of gas wells under a pooling order in which there is a nonconsenting owner shall furnish the nonconsenting owner with a monthly statement of all costs incurred, together with the quantity of gas produced, and the amount of proceeds realized from the sale of production during the preceding month. If the consenting owners recover the costs specified in subdivision 6 of this section, the nonconsenting owner shall own the same interest in the wells and the production there from and be liable for the further costs of the operation, as if the nonconsenting owner had participated in the initial drilling operations.

RECLAMATION OF GAS RESOURCE DEVELOPMENT LOCATIONS

Section 11. 93. 5171 DECLARATION OF POLICY.

In recognition of the effects of the development of gas resources upon the environment, it is the policy of this state to provide for the reclamation of gas resource development locations where such reclamation is necessary, both in the interest of the general welfare and as an exercise of the police power of the state, to control possible adverse environmental effects of the development of gas resources, to preserve the natural resources, and to encourage the planning of future land utilization, while at the same time promoting the orderly development of gas resources, the encouragement of good gas resource development practices, and recognizing the beneficial aspects of gas resource development.

Section 12. 93.51711 DEFINITIONS

Subdivision 1. **Applicability.** For the purposes of sections 93.5171 to 93.51780, the terms defined in this section have the meanings given to them.

Subd. 2. **Commissioner.** "Commissioner" means the commissioner of natural resources.

Subd. 3. **Contingency reclamation plan.** "Contingency reclamation plan" means a plan that identifies reclamation activities, including closure and post closure maintenance work, that would be implemented by the permittee if operations ceased or if producing gas wells were idled for more than 36 months. This plan must include methods, sequence, and schedule of reclamation activities, maps and cross sections that depict gas resource development locations both before and after reclamation activities are completed, and cost estimates necessary to implement the contingency reclamation plan.

Subd. 4. **Corrective action.** "Corrective action" means the immediate actions that must be taken to correct observed violations of the gas resource development permit. Corrective action may consist of immediately curing the violation, or submitting, within two weeks, a corrective action plan for approval before the permittee implements the corrective action.

Subd. 5. **Department.** "Department" means the Department of Natural Resources.

Subd. 6 **Gas.** "Gas" shall include both petroleum and non-petroleum gases.

Subd. 7 **Gas well.** "Gas well" shall mean a gas well as defined in Minnesota Statutes, section 103I.005, subd. 10b, sited at a gas resource development location.

Subd. 8. **Natural Resources.** "Natural resources" means all mineral, animal, botanical, air, water, land, timber, soil, quietude, recreational, historical, scenic, and aesthetic resources in accordance with Minnesota Statutes, section 116B.02, subdivision 4.

Subd. 9. **Gas resource development plan.** "Gas resource development plan" means a plan to develop gas resources at one or more gas resource development locations.

Subd. 10. **Gas resource development facility.** "Gas resource development facility" means equipment or improvements used or installed at a gas resource development location for the exploration, production, withdrawal, treatment, or processing of exploration and production waste or gas.

Subd. 11. **Gas resource development location.** "Gas resource development location" shall mean a definable area where an operator has disturbed or intends to disturb the land surface in order to locate a gas resource development facility.

Subd. 12. **Gas resource development operations.** "Gas resource development operations" means exploring for gas resources by siting, drilling, deepening, recompleting, reworking, or abandoning a gas well; producing operations related to any gas well, including installing flowlines; the generating, transporting, storing, treating, or disposing exploration and production wastes; and any constructing, site preparing, or reclaiming activities associated with such operations.

Subd. 13. **Operator.** "Operator" means any owner or lessee of mineral rights engaged in or preparing to engage in gas resource development operations with respect thereto.

Subd. 14. **Person.** "Person" includes firms, partnerships, corporations, and other groups.

Subd. 15. **Permittee.** "Permittee" is a person who holds a gas resource development permit. All persons engaged in or carrying out the operation must jointly hold the permit. This includes all parent companies of persons involved in the operation.

Supd. 16. **Reclamation.** "Reclamation" means the actions required to comply with sections 93.5171 to 93.51780 regarding decommissioning of a gas resource development facility and restoration of any associated gas resource development locations.

Section 13. 93.5172 DUTIES AND AUTHORITY OF COMMISSIONER.

The commissioner must administer and enforce sections 93.5171 to 93.51780 and the rules adopted pursuant thereto and authorized by section 93.514. In so doing the commissioner may:

(1) conduct such investigations and inspections as the commissioner deems necessary for the proper administration of sections 93.5171 to 93.51780;

(2) enter upon any parts of a gas resource development location in connection with any such investigation and inspection without liability to the operator or landowner provided that reasonable prior notice of intention to do so must have been given the operator or landowner;

(3) conduct such research or enter into contracts related to gas resource development locations and the reclamation thereof as may be necessary to carry out the provisions of sections 93.5171 to 93.51780; and

(4) allocate surplus wetland credits that are approved by the commissioner under a gas resource development permit and that are not otherwise deposited in a state wetland bank.

Section 14. 93.5173 VARIANCE.

The commissioner may, upon application by the operator, modify or permit variance from the established rules adopted hereunder if it is determined that such modification or variance is consistent with the general welfare.

Section 15. 93.5174 GAS RESOURCE DEVELOPMENT PERMIT.

Subdivision 1. **Prohibition against gas resource development operations without permit; application for permit.** No person may engage in or carry out gas resource development operations at gas resource development locations, including the drilling of gas wells or extraction of gas resources, within the state unless the person has first obtained a gas resource development permit from the commissioner. Any person applying to the commissioner of natural resources for such a permit must submit such information as the commissioner may require, including but not limited to the following:

(a) an application fee of $50,000.
(b) a certificate issued by an insurance company authorized to do business in the United States that the applicant has a public liability insurance policy in force for the development of gas resources for which the permit is sought, or evidence that the applicant has satisfied other state or federal self-insurance requirements, to provide personal injury and property damage protection in an amount adequate to compensate any persons who might be damaged as a result of the gas resource development operations or any reclamation or restoration operations connected with gas resource development locations;
(c) a map that identifies the location of established or applicant-proposed spacing units, the location and extent of all proposed gas resource development locations, access roads, gas wells and setback distances between each gas well and areas with special land uses within the proposed spacing unit.
(d) a plan map that shows the planned locations of planned gas resource development facilities on all gas resource development locations, including drill pads, gas enrichment facilities, storage tanks and flowlines
(e) a proposed plan for construction of gas resource development facilities, including but not limited to gas wells, processing or gas enrichment plants, and connecting flowlines;
(f) a proposed plan for gas resource development operations, including but not limited to duration of project, processes and procedures for gas extraction, enrichment, storage and gas transport to market, and the isolation and management of noncommercial gases extracted from gas wells;
(g) a proposed plan, including timeline, for the reclamation or restoration, or both, of any gas resource development location affected by operations to be conducted on and after the date on which permits are required for the development of gas resources under this section;
(h) characterization of any exploration and production waste to be stored temporarily or permanently at a gas resource development location;
(i) plans for financial assurance instrument(s) addressing cost to close all gas resource development facilities and reclaim all gas resource development locations;

(j) a copy of the applicant's advertisement of the ownership, location, and boundaries of the proposed gas resource development locations, which advertisement must be published in a legal newspaper in the locality of the proposed site at least once a week for four successive weeks before the application is filed.

Subd. 2. **Permits issued during rulemaking.** A gas resource development permit issued during the pendency of expedited rulemaking authorized under 93.514 will not expire once those rules are promulgated, so long as the person holding that permit continues to operate under permitted conditions. Should a person holding such a permit apply for a permit amendment after rules are promulgated, the promulgated rules will apply to operations covered by both the amendment and the original permit, and the application for a permit amendment must include such information as the commissioner may require as in subdivision 1 and in accordance with promulgated rules for the entire project.

Subd. 3. **Commissioner's review; hearing.** After receiving an application the commissioner has deemed complete and filed, the commissioner must grant the permit applied for, with or without modifications or conditions, or deny the application unless a contested case hearing is requested or ordered under section 93.5176. The commissioner's decision to grant the permit, with or without modifications, or deny the application constitutes a final order for purposes of section 93.5179. The commissioner in granting a permit with or without modifications must determine that the reclamation or restoration planned for the operation complies with lawful requirements and can be accomplished under available technology and that a proposed reclamation or restoration technique is practical and workable under available technology. The commissioner may hold public meetings on the application.

Subd. 4. **Term of permit; amendment.** (a) A permit issued by the commissioner pursuant to this section must be granted for the term determined necessary by the commissioner for the completion of the proposed gas resource development plan, including reclamation or restoration.

(b) A permit may be amended upon written application to the commissioner. A permit amendment application fee must be submitted with the written application. The permit amendment application fee is ten percent of the amount provided for in subdivision 1, clause (3) for an application for a gas resource development permit. If the commissioner determines that the proposed amendment constitutes a substantial change to the permit, the person applying for the amendment must publish notice in the same manner as for a new permit. An amendment may be granted by the commissioner if the commissioner determines that lawful requirements have been met.

Subd. 5. **Revocation; modification; suspension.** A permit is irrevocable during its term except as follows:

(a) The permittee has not commenced substantial construction of gas resource development facilities or actual production and reclamation or restoration operations covered by the permit within 36 months of issuance of the permit.

(b) A permit may be canceled at the request of or with the consent of the permittee upon such conditions as the commissioner determines necessary for the protection of the public interests.

(c) Subject to the rights of the permittee to contest the commissioner's action under sections 14.57 to 14.59 and related sections, a permit may be modified or revoked by the commissioner in case of any breach of the terms or conditions thereof or in case of violation of law pertaining thereto by the permittee, or agents of the permittee, or in case the commissioner finds such modification or cancellation necessary to protect the public health or safety, or to protect the public interests in lands or waters against injury resulting in any manner or to any extent not expressly authorized by the permit, or to prevent injury to persons or property resulting in any manner or to any extent not so authorized, upon at least 30 days' written notice to the permittee, stating the grounds of the proposed modification or revocation or providing a reasonable time of not less than 15 days in which to take corrective action and giving the permittee an opportunity to be heard thereon.

(d) By written order to the permittee, the commissioner may suspend operations under a permit if the commissioner finds it necessary in an emergency to protect the public health or safety or to protect public interests in lands or waters against imminent danger of substantial injury in any manner or to any extent not expressly authorized by the permit, or to protect persons or property against such danger, and may require the permittee to take any measures necessary to prevent or remedy such injury. No suspension order under this clause may be in effect more than 30 days from the date thereof without giving the permittee at least ten days' written notice of the order and an opportunity to be heard thereon.

Subd. 6. **Assignment.** A permit may not be assigned or otherwise transferred without the written approval of the commissioner. A permit assignment application fee must be submitted with the written application. The permit assignment application fee is ten percent of the amount provided for in subdivision 1, clause (1). A permit assignment application may be combined with a permit.

Subd. 7. **Gas resource administration account.** The gas resource administration account is established as an account in the natural resources fund. Fees charged to owners, operators, or managers of operations under sections 93.515 to 93.51780 shall be credited to the gas resource administration account and are appropriated to the commissioner to cover the costs of providing and monitoring gas resource development permits. Earnings accruing from investment of the account remain with the account.

Section 16. **Temporary regulatory framework**. To support a temporary regulatory framework for permitting gas production projects during rulemaking, the following items are in effect until rules are adopted for siting, permitting and reclamation requirements for gas production projects, as required under 93.514:

(1) All gas resource development locations must incorporate setbacks or separations that are needed to comply with air, water, and noise pollution standards; local land use regulations; and requirements of other appropriate authorities. Nothing in this section is intended to supersede any more restrictive siting or setback requirements that may exist in state or federal laws for the specific land designations listed below. In addition, development operations at gas resource development locations must not modify or alter the gas resources of certain areas, except in the event of a national emergency declared by Congress.

(2) A gas resource development location must not be located within or alter the gas resources of the following:

(a) the Boundary Waters Canoe Area Wilderness, as legally described in the Federal Register, volume 45, number 67 (April 4, 1980), with state restrictions specified in Minnesota Statutes, section 84.523, subdivision 3;

(b) Voyageurs National Park, with state restrictions specified in Minnesota Statutes, section 84B.03, subdivision 1; and,§

(c) Agassiz and Tamarac National Wilderness areas, and Pipestone and Grand Portage National monuments.

(3) Passive subsurface gas resource development activities are allowed, but gas resource development locations and subsurface directional drilling are prohibited in the following:

(a) state wilderness areas;

(b) state scientific and natural areas;

(c) within state peatland scientific and natural areas where such activities would not significantly modify or alter the peatland water levels or flows, peatland water chemistry, plant or animal species or communities, or natural features of the peatland scientific and natural areas, except in the event of a national emergency declared by Congress;

(d) calcareous fens identified in Minnesota Statutes, section 103G.223;

(e) a state park, except that gas resource development operations shall be allowed if the park has been established as a result of its association with mining; and,

(f) designated trout streams and lakes.

(4) Subsurface gas resource development activities, including subsurface directional drilling, are allowed, but gas resource development locations are prohibited in the following:

(a) within the Boundary Waters Canoe Area Wilderness Mineral Management Corridor, identified on the Department of Natural Resources map entitled "Minnesota Department of Natural Resources B.W.C.A.W. Mineral Management Corridor," dated February 1991, which map is hereby incorporated by reference, is not subject to frequent change, and is available through the State Law Library;

(b) within one-fourth mile of Voyageurs National Park;

(c) within one-fourth mile of state wilderness areas;

(d) within one-fourth mile of Agassiz and Tamarac National Wilderness areas, and Pipestone and Grand Portage National monuments;

(e) within one-fourth mile of state scientific and natural areas;

(f) within one-fourth mile of state parks, except surface and subsurface disturbances shall be allowed if the park has been established as a result of its association with mining;

(g) within one-fourth mile of calcareous fens identified under Minnesota Statutes, section 103G.223;

(h) on sites designated in the National Register of Historic Places, except that gas resource development operations shall be allowed if the sites have been established as a result of their association with mining;

(i) on sites designated in the Registry of State Historic Sites, except gas resource development operations shall be allowed if the sites have been established as a result of their association with mining;

(j) within national wild, scenic, or recreational river districts of a national wild, scenic, or recreational river, and within the areas identified by the document, "A Management Plan for the Upper Mississippi River," produced by the Mississippi Headwaters Board, dated January 1981, which document is hereby incorporated by reference, is not subject to frequent change, and is available through the State Law Library;

(k) within designated state land use districts, of a state wild, scenic, or recreational river, and,

(l) within the area adjacent to the north shore of Lake Superior identified in the document entitled, "North Shore Management Plan," produced by the North Shore Management Board, dated December 1988, which document is hereby incorporated by reference, is not subject to frequent change, and is available through the State Law Library.

(m) in the following areas, provided they were in existence before the issuance of a gas resource development permit:

(i) within 500 feet of an occupied dwelling, public school, church, public institution, or county or municipal park, unless allowed by the owner; and

(ii) within 100 feet of a cemetery, or the outside right-of-way line of a public roadway.

(5) Gas resource development locations shall be allowed in the following areas only if there is no prudent and feasible siting alternative, as determined by the commissioner:

(a) within a national wildlife refuge, a national waterfowl protection area, or on a national trail;

(b) within a state wildlife management area, or on a state designated trail either listed in Minnesota Statutes, section 85.015, or acquired under the authority of Minnesota Statutes, section 84.029, subdivision 2;

(c) in peatlands identified as peatland watershed protection areas in the Department of

Natural Resources report entitled "Protection of Ecologically Significant Peatlands in Minnesota," dated November 1984, which report is hereby incorporated by reference, is not subject to frequent change, and is available through the State Law Library; and

(d) within waters identified in the public waters inventory, conducted under Minnesota Statutes, section 103G.201, that have not been created or substantially altered in size by human activities, and within the adjoining shorelands, as defined in Minnesota Statutes, section 103F.205, subdivision 4, of the unaltered waters.

(5) A gas resource development permit must include as a permit condition a requirement that a permittee submit to the commissioner a preproduction report at least 60 days prior to the commercial extraction of gas resources from gas wells drilled at gas resource development locations. This report must include data and test results from completed gas wells that can be used to evaluate the production rates and extraction areas that were incorporated by the permittee into their permit application, prior to drilling the gas wells. The specific types of data and other report components must be identified by the commissioner within the associated gas resource development permit.

(6) A permittee must submit an annual report to the commissioner by March 31 of each year that describes actual gas production and reclamation completed during the past year, gas production and reclamation activities planned for the upcoming year, and a contingency reclamation plan to be implemented if operations cease or gas wells were idled for more than 36 months. The annual report must include, at a minimum, reporting for the previous calendar year and projections for the upcoming calendar year on the volume and average composition of raw gas extracted from each gas well covered by the gas resource development plan, quantities and final grades of commercial gas products transported to market, any changes in the production or gas enrichment processes, a description of reclamation activities and correction actions, evidence of continued liability insurance, and a discussion of any changes in ownership and organization structure of the permittee.

Section 17. 93.5175 RECLAMATION FEES.

Subdivision 1. **Annual gas resource development permit fee.** (a) The commissioner must charge every person holding a gas resource development permit an annual permit fee. The fee is payable to the commissioner by June 30 of each year, beginning in 2025. If a temporary permit is issued after June 30 of any year, the permittee must pay the annual fee within 60 days of permit issuance.

(b) The annual permit fee for gas resource development is $75,000 if the operation had production within the calendar year immediately preceding the year in which payment is due and $37,500 if there was no production within the immediately preceding calendar year.

Subd. 2. **Supplemental application fee.** (a) In addition to the application fee specified in section 93.5174, the commissioner must assess a person submitting an application for a gas resource development permit the reasonable costs for reviewing the application and preparing the permit. The commissioner must also assess reasonable costs for monitoring construction of the gas resource development facilities.

(b) The commissioner must give the applicant an estimate of the supplemental application fee under this subdivision. The estimate must include a brief description of the tasks to be performed and the estimated cost of each task. The application fee under section 93.5174 must be subtracted from the estimate of costs to determine the supplemental application fee.

(c) The applicant and the commissioner must enter into a written agreement to cover the estimated costs to be incurred by the commissioner.

(d) The commissioner must not issue the gas resource development permit until the applicant has paid all fees in full. Upon completion of construction of all gas resource development facilities, the commissioner must refund the unobligated balance of the monitoring fee revenue.

Section 18. 93.5176 CONTESTED CASE.

Subdivision 1. **Petition for contested case hearing.** Any person owning property that will be affected by the proposed gas resource development operations or any federal, state, or local government having responsibilities affected by the proposed operation identified in the application for a gas resource development permit under section 93.5174 may file a petition with the commissioner to hold a contested case hearing on the completed application. To be considered by the commissioner, a petition must be submitted in writing, must contain the information specified in subdivision 2, and must be submitted to the commissioner within 30 days after the application is deemed complete and filed. In addition, the commissioner may, on the commissioner's own motion, order a contested case hearing on the completed application.

Subd. 2. **Petition contents.** (a) A petition for a contested case hearing must include the following information:

(1) a statement of reasons or proposed findings supporting the commissioner's decision to hold a contested case hearing pursuant to the criteria in subdivision 3; and

(2) a statement of the issues proposed to be addressed by a contested case hearing and the specific relief requested or resolution of the matter.

(b) To the extent known by the petitioner, a petition for a contested case hearing may also include:

(1) a proposed list of prospective witnesses to be called, including experts, with a brief description of the proposed testimony or a summary of evidence to be presented at a contested case hearing;

(2) a proposed list of publications, references, or studies to be introduced and relied upon at a contested case hearing; and

(3) an estimate of time required for the petitioner to present the matter at a contested case hearing.

(c) A petitioner is not bound or limited to the witnesses, materials, or estimated time identified in the petition if the requested contested case is granted by the commissioner.

(d) Any person may serve timely responses to a petition for a contested case hearing. The commissioner shall establish deadlines for responses to be submitted.

Subd. 3.**Commissioner's decision to hold hearing.** (a) The commissioner must grant the petition to hold a contested case hearing or order upon the commissioner's own motion that a contested case hearing be held if the commissioner finds that:

(1) there is a material issue of fact in dispute concerning the completed application before the commissioner;

(2) the commissioner has jurisdiction to make a determination on the disputed material issue of fact; and

(3) there is a reasonable basis underlying a disputed material issue of fact so that a contested case hearing would allow the introduction of information that would aid the commissioner in resolving the disputed facts in order to make a final decision on the completed application.

(b) The commissioner must make the determination of whether to grant a petition or otherwise order a contested case hearing within 120 days after the commissioner deems the application complete and filed.

Subd. 4.**Hearing upon request of applicant.** The applicant may, within 30 days after the application is deemed complete and filed, submit a request for a contested case. Within 30 days of the applicant's request, the commissioner shall grant the petition and initiate the contested case hearing process.

Subd. 5.**Scope of hearing.** If the commissioner decides to hold a contested case hearing, the commissioner shall identify the issues to be resolved and limit the scope and conduct of the hearing in accordance with applicable law, due process, and fundamental fairness. The commissioner may, before granting or ordering a contested case hearing, develop a proposed permit or permit conditions to inform the contested case. The contested case hearing must be conducted in accordance with sections 14.57 to 14.62. The final decision by the commissioner to grant, with or without modifications or conditions, or deny the application after a contested case shall constitute a final order for purposes of section 93.5179.

Section 19. 93.5177 ENVIRONMENTAL REVIEW FEES.

Subdivision 1. **Assessment**. The commissioner of natural resources must assess a gas resource development permit applicant the reasonable costs of preparing, reviewing, and distributing the associated environmental assessment worksheet through the Record of Decision, as required by (EQB draft statute number). The applicant and the commissioner must enter into a written agreement to cover the estimated costs to be incurred by the commissioner.

Subd. 2. **Full cost to be paid**. The commissioner must not commence the preparation of an environmental assessment worksheet until the full assessed cost of the environmental assessment worksheet is paid pursuant to subdivision 1. Other laws nothwithstanding, no state agency may issue any permits for the development of gas resources for which an environmental assessment worksheet is prepared until the final assessed cost for the environmental assessment worksheet has been paid in full.

Section 20. 93.5178 FINANCIAL ASSURANCE OF OPERATOR.

Subdivision 1. **Requirement for financial assurance.** The commissioner must require a bond or other security or other financial assurance satisfactory to the commissioner from a permittee. The commissioner must review at least annually the extent of each operator's financial assurance under this section.

Section 21. Temporary regulatory framework. To support a temporary regulatory framework for permitting gas production projects during rulemaking, the following items are in effect until rules are adopted for financial assurance requirements for gas production projects, as required under 93.514:

(1) Financial assurance for reclamation and for corrective action must ensure that funds will be:

(a) available to cover the costs estimated in subsection (2);
(b) made payable to the commissioner when needed;
(c) fully valid, binding, and enforceable under state and federal law;
(d) not be dischargeable through bankruptcy;
(e) not include any corporate guarantees unless a guarantee is deemed necessary by the commissioner as an additional layer of assurance beyond the use of bonds, other securities, or other financial assurance mechanisms that meet criteria (a) through (d) and (f) of this subsection and in no case shall a corporate guarantee be approved as a stand0alone financial assurance; and,
(f) all terms and conditions of the financial assurance must be approved by the commissioner.

(2) A person intending to develop gas resources shall submit, as part of an application for a gas resource development permit, a documented estimate of costs necessary for the reclamation or restoration, or both, of any gas resource development locations upon which the person proposes to conduct gas resource development operations. The procedures for completing this cost estimate and its required elements shall be determined by the commissioner.

(3) If a corrective action is required during implementation of the gas resource development plan to minimize waste and protect human health or the environment, the permittee shall submit to the commissioner a cost estimate for completing the required actions. The commissioner shall determine the procedures and required elements for completing this corrective action cost estimate.

(4) The commissioner shall evaluate submitted cost estimates and cost estimate adjustments using individuals with documented experience in material handling and the reclamation or restoration of gas resource development locations. The applicant must pay the costs incurred by the commissioner to hire third parties to perform this evaluation.

(5) Financial assurance in the amount equal to the contingency reclamation cost estimate shall be submitted to the commissioner for approval before issuance of a gas resource development permit and before granting an amendment to the permit, shall be continuously maintained by the permittee, and annually adjusted based on the new cost estimate.

(6) Financial assurance in the amount equal to the corrective action cost estimate under paragraph (6) shall be submitted to the commissioner for approval as part of the corrective action cost estimate, continuously maintained by the permittee until the commissioner determines it is no longer necessary; and annually adjusted based on the new cost estimate.

(7) Financial assurances may be canceled by the permittee, on approval by the commissioner, only after it is replaced by an alternate mechanism or after the permittee is released from financial

assurance once the commissioner determines, through inspection of the permitted gas resource development locations, that all reclamation activities have been completed according to the gas resource development permit, conditions necessitating postclosure maintenance no longer exist and are not likely to recur, and corrective actions have been successfully accomplished.
(8) The permittee must ensure that the provider of financial assurance gives the commissioner 120 days' notice prior to cancellation of the financial assurance mechanism. Upon receipt of this notice, the commissioner shall initiate a proceeding to access the financial assurance.
(9) If the gas resource development permit is assigned, the new permittee must be in compliance with requirements of this part before the commissioner approves the assignment. On the assignee's demonstration of compliance with this part, the former permittee shall be released from the requirements of this part.
(10) Financial assurance must be made available to the commissioner when the operator is not in compliance with either a contingency reclamation plan or corrective action plan.
(11) The commissioner may deny, suspend, revoke or modify a gas resource development permit or assess civil penalties if the permittee fails to comply with any portion of this part.

Section 22. 93.5179. APPEAL.

Any person aggrieved by any final order, ruling, or decision of the commissioner may obtain judicial review of such order, ruling, or decision under sections 14.63 to 14.69.

Section 23. 93.5180. PENALTIES FOR VIOLATION.

Subdivision 1. **Civil penalty.** If any person fails to comply with any provision of sections 93.5171 to 93.51780, or any rules promulgated pursuant to these sections, or any permit condition required by these sections or the rules, for a period of 15 days after notice of such failure, or the expiration of time for corrective action as provided for in section 93.5174, subdivision 5, such person must be liable for a civil penalty of not more than $10,000 per day per violation for each and every day of the continuance of such failure. The commissioner may assess and collect any such penalty for deposit in the mining administration account.

Subd. 2. **Criminal penalty; injunctive relief.** Any person who knowingly and willfully violates or refuses to comply with any rule, decision, order, or ruling of the commissioner must upon conviction be guilty of a gross misdemeanor. At the request of the commissioner, the attorney general may institute a civil action in a district court of the state for a restraining order or injunction or other appropriate remedy to prevent or preclude a violation of the terms and conditions of any rules promulgated hereunder. The district court of the state of Minnesota in which district the extraction operation affected is conducted must have jurisdiction to issue such order or injunction or to provide other appropriate remedies.

Section 24. Section 93.55 is amended as follows:

93.55 FORFEITURE OF SEVERED MINERAL INTEREST.

Subd. 1a. **Lease of forfeited interest.** If the owner of a severed mineral interest fails to record the verified statement required by section 93.52 before the dates specified in subdivision 1, the commissioner of natural resources may lease the mineral interest as provided in this subdivision and subdivision 3 before completing the procedures set forth in subdivision 2. In any lease issued under this subdivision, the commissioner shall cite, as authority for issuing the lease, this subdivision, subdivision 3, and the United States Supreme Court decision in Texaco, Inc., et al. v. Short, et al., 454 U.S. 516 (1982), where the Supreme Court determined, under Amendment XIV to the Constitution of the United States, that enactment of a state law requiring an owner of severed mineral interests to timely record a statement of claim to the mineral interests was constitutional, without individual advance notice of operation of the law, before the owner loses the mineral interests for failing to timely record the statement of claim. A lessee holding a lease issued under this subdivision may not mine <u>or extract gas or other mineral resources</u> under the lease until the commissioner completes the procedures set forth in subdivision 2 and a court has adjudged the forfeiture of the mineral interest to be absolute. "Mine" for the purposes of this subdivision is defined to exclude exploration activities, exploratory boring, trenching, test pitting, test shafts and drifts, and related activities.

[93.514] GAS AND OIL PRODUCTION RULEMAKING.

(a) The following agencies may adopt rules governing gas and oil exploration or production, as applicable:

(2) ~~the commissioner of health may adopt or amend rules on groundwater and surface water protection, exploratory boring construction, drilling registration and licensure, and inspections as they pertain to the exploration and appraisal of gas and oil resources;~~

103I.001 LEGISLATIVE INTENT.

This chapter is intended to protect the health and general welfare by providing a means for the ~~development and~~ protection of the natural resource of groundwater in an orderly, healthful, and reasonable manner.

103I.005 DEFINITIONS.

Subd. 9. **Exploratory boring.** "Exploratory boring" means a surface drilling done to explore or prospect for ~~oil, natural~~ gas, apatite, diamonds, graphite, gemstones, kaolin clay, and metallic minerals, including iron, copper, zinc, lead, gold, silver, titanium, vanadium, nickel, cadmium, molybdenum, chromium, manganese, cobalt, zirconium, beryllium, thorium, uranium, aluminum, platinum, palladium, radium, tantalum, tin, and niobium.~~, and a drilling or boring for petroleum.~~

Subd. 10a. **Gas.** “Gas” includes both hydrocarbon and nonhydrocarbon gases.

Subd. 10b. **Gas well.** “Gas well” means an excavation that is constructed to locate, extract, or produce gas.

Subd. 10c. **Gas well contractor.** “Gas well contractor” means a person with a gas well contractor’s license issued by the commissioner.

Subd. 21. **Well.** "Well" means an excavation that is drilled, cored, bored, washed, driven, dug, jetted, or otherwise constructed if the excavation is intended for the location, diversion, artificial recharge, monitoring, testing, remediation, or acquisition of groundwater. Well includes environmental wells, drive point wells, and dewatering wells. "Well" does not include:

(1) an excavation by backhoe, or otherwise for temporary dewatering of groundwater for nonpotable use during construction, if the depth of the excavation is 25 feet or less;

(2) an excavation made to obtain or prospect for oil,~~ natural~~ gas, minerals, or products of mining or quarrying;

(3) an excavation to insert media to repressure oil or ~~natural~~ gas bearing formations or to store petroleum, ~~natural~~ gas, or other products;

(4) an excavation for nonpotable use for wildfire suppression activities; ~~or~~

(5) borings; or

(6) gas and oil wells.

EFFECTIVE DATE. This section is effective the day following final enactment.

103I.601 EXPLORATORY BORING PROCEDURES.

Subdivision 1. (e) "gas exploratory boring" means an exploratory boring encountering gas for at least 24 hours and in which gas has not dissipated prior to sealing.

Subd. 10. Borings encountering gas. This subdivision contains requirements only for gas exploratory borings.

(a) An explorer must notify the commissioner of health and the commissioner of natural resources:

(1) within 24 hours of drilling a gas exploratory boring; and

(2) prior to beginning permanent sealing of a gas exploratory boring.

(b) An explorer must submit a permanent sealing notification and fee of $125.00 to the commissioner prior to permanently sealing a gas exploratory boring.

(c) An explorer must begin permanent sealing of a gas exploratory boring within 10 days of encountering gas.

(d) A gas exploratory boring is exempt from item (c) if the boring is constructed to prevent movement of gas and water from one formation to another. The boring must be permanently sealed within 30 days after the completion of drilling unless gas is no longer present in the boring.

(e) A gas exploratory boring must be permanently sealed from the bottom of the boring to within two feet of the established ground surface.

(f) A permanent sealing report as required by subdivision 9 must also contain information indicating that gas was encountered during construction and at what depth it was encountered.

(g) A person must not use an exploratory boring to extract gas for production.

Subd. 11. **Conversion of a gas well prohibited.** A person must not convert a gas well to any other type of well or boring.

Subd. 12. **Conversion of a well or boring to a gas well.** A person must not convert a well or boring to a gas well, except that an exploratory boring constructed before enactment of section 103I.707 may be converted to a gas well if constructed in accordance with provisions of section 103I.707, except that the outermost casing may be:

(a) ASTM Standard A53;

(b) ASTM Standard A589, Types I, II, and III;

(c) API Specification 5L; or

(d) API Specification 5CT.

EFFECTIVE DATE. This section is effective the day following final enactment.

103I.706 GAS WELLS.

Subdivision 1. **Rulemaking Authority.** The commissioner of health shall adopt rules for gas wells according to chapter 14.

Subd. 2. **Fees.** License, certification, and registration renewals are not prorated and expire on December 31st of each year.

(a) A person must meet the gas well contractor license requirements and fee requirements to construct, repair, or seal a gas well. The fee for a gas well contractor license is $300.00. The annual renewal fee for a gas well contractor license is $300.00.

(b) A gas well contractor must designate a certified representative. The certified representative must meet the application and fee requirements. The application fee for a certified representative is $100.00. The annual renewal fee for a certified representative is $100.00.

(c) A person must meet the registration and fee requirements for rigs used to construct, repair, service, or seal a gas well. The fee to register gas well rigs is $125.00. The annual renewal fee for gas well rig registration is $125.00.

(d) If a licensee or certified representative under items (a) and (b) fails to submit all information required for renewal or submits the application and information after the required renewal date:

(1) the licensee or certified representative must include a late fee of $75; and

(2) the licensee or certified representative may not conduct activities authorized by the gas well contractor's license or certified representative's certification until the renewal application, renewal application fee, and all other information required is submitted.

(e) A person must submit a notification for construction of a proposed gas well on a form prescribed by the commissioner, with a fee of $10,000.

(f) A person must submit a notification for sealing a gas well on a form prescribed by the commissioner, with the fee of $7,500.

Subd. 3. **Rig registration.** (a) Rigs used to drill, maintain, repair, or seal a gas well, including drilling rigs and workover rigs, must be registered with the commissioner.

(b) A person must file an application to register a rig on a form provided by the commissioner and fee, under section 103I.706, subdivision 2, item c, with the commissioner.

(c) A registration is valid until the date prescribed by the commissioner in the registration.

(d) A person must file an application and fee, under section 103I.706, subdivision 2, item c, to renew the registration by the date prescribed by the commissioner in the registration.

Subd. 4**. Gas Well Contractor's License.** (a) A person must not construct, repair, or seal a gas well, without a gas well contractor's license issued by the commissioner.

(1) A person must file a complete application on a form provided by the commissioner and fee, under section 103I.706, subdivision 2, item a, with the commissioner. The person applying must meet the qualifications for a gas well contractor license.

(2) A gas well contractor's license is valid until the date prescribed by the commissioner in the license.

(3) A gas well contractor must file a complete application and fee, under section 103I.706, subdivision 2, item a, to renew the license by the date prescribed by the commissioner in the license. A person must not construct, repair, or seal a gas well until a gas well contractor's license is renewed. The commissioner may not renew a license until the renewal fee is paid.

(4) A gas well contractor must include information at the time of renewal that the applicant has met the continuing education requirements established by the commissioner in rule.

(b) A gas well contractor must designate a certified representative to supervise and oversee regulated work on gas wells.

(1) A person must file a complete application on a form provided by the commissioner and fee, under section 103I.706, subdivision 2, item b, to qualify as a certified representative.

(2) A certified representative must file an application and fee, under section 103I.706, subdivision 2, item b, to renew the certification by the expiration date prescribed by the commissioner on the certification. A certified representative may not supervise or oversee regulated work on a gas well until the renewal application and application fee are submitted. The commissioner may not review a certification until the renewal fee is paid.

(3) A certified representative must include information at the time of renewal that the applicant has met the continuing education requirements established by the commissioner in rule.

(c) The commissioner of natural resources may require a bond, security, or other assurance from a gas well contractor if the commissioner of natural resources has reasonable doubts about the person's financial ability to comply with requirements of law relating to reclamation of a gas well and process to restore the land disturbed by a gas well drilling and production operations back to a condition of original state.

(d) The commissioner may suspend or revoke a licensee's license according to Minnesota Statutes, section 144.99.

Subd. 5. **Construction notification.** (a) A gas well contractor must not begin drilling or constructing a gas well until the person has a valid gas resource development permit from the commissioner of natural resources.

(b) The person must submit a notification to the commissioner to construct a gas well after receiving permit approval from the commissioner of natural resources and prior to drilling or constructing a gas well. A gas well contractor must file the gas well notification, and fee, under section 103I.706, subdivision 2, item e, with the commissioner.

Subd. 6. **Access to drill sites.** (a) The commissioner of health shall have access to gas well sites to inspect gas wells, including the drilling, construction and sealing of gas wells.

(b) The commissioner of health has enforcement authority according to Minnesota Statutes, section 144.99.

Subd. 7. **Emergency notification.** In the event of an occurrence during a construction, repair, or sealing of a gas well that has a potential for significant adverse public health or environmental effects, the person drilling or constructing a gas or well must promptly:

(a) take reasonable action to minimize the adverse effects; and,

(b)notify the commissioners of health, natural resources, and the Pollution Control Agency immediately by informing the Minnesota Duty Officer.

Subd. 8. **Sealing notification.** (a) A gas well, including an unsuccessful gas well, that is not in use must be sealed by a gas well contractor.

(b) A gas well contractor must file a notification, and fee, with the commissioner prior to sealing a gas well.

Subd. 9. **Report of work.** Within 60 days after completion or sealing of a gas well, the gas well contractor must submit a verified report to the commissioner on a form prescribed by the commissioner, or in a format approved by the commissioner.

EFFECTIVE DATE. This section is effective the day following final enactment.

103I.707 GAS WELL NOTIFICATION AND CONSTRUCTION

Subd.1. **Definitions**.

(a) For the purposes of this section, the following words have the meanings given them.

(b) "Casing" means an impervious durable pipe placed in a well to prevent the walls from caving and to seal off surface drainage or undesirable water, gas, or other fluids to prevent their entering the well and the groundwater.

(c) "Confining layer" means a geological material that restricts water movement relative to an aquifer. A confining layer includes:

i. a stratum of unconsolidated materials or bedrock ten feet or more in vertical thickness that has a vertical hydraulic conductivity of 10^{-6} centimeters per second or less;

ii. a stratum of clay, sandy clay, or silty clay ten feet or more in vertical thickness, as defined in the Soil Survey Manual, incorporated by reference in United States Bureau of Plant Industry, Soils and

Agricultural Engineering, Soil Survey Manual, United States Department of Agriculture Handbook, no. 18 (1951), pages 205 to 213.; or

iii. any portion of the Decorah, Glenwood, St. Lawrence, or Eau Claire sedimentary bedrock formations as described in Paleozoic Lithostratigraphy of Southeastern Minnesota, incorporated by reference in George Austin, "Paleozoic Lithostratigraphy of Southeastern Minnesota," in Geology of Minnesota: A Centennial Volume in Honor of George M. Schwartz (P.K. Sims and G.B. Morey eds., 1972), pages 459 to 473.

(d) “Drilling fluid additive” is a substance added to the air or water used in the fluid system of drilling a gas well.

(e) “Hydraulic Fracturing Treatment” means all stages of the treatment of a well by the application of fluid under pressure that is expressly intended to initiate or propagate fractures in a target geologic formation to enhance production of oil and gas.

(f) “Neat cement grout” means a mixture in the proportion of 94 pounds of Portland cement and not more than six gallons of clean water. Bentonite up to five percent by weight of cement (4.7 pounds of bentonite per 94 pounds of Portland cement) may be used to reduce shrinkage. Admixtures meeting the standard specifications of ASTM Standard C494 may be used to reduce permeability and/or control time of set.

(g) "Person" means an individual, firm, partnership, association, or corporation or any other entity including the United States government, any interstate body, the state, and any agency, department, or political subdivision of the state.

(h) “Production” includes extraction and beneficiation of gas from consolidated or unconsolidated formations in the state.

(i) “Surface casing” means a string of casing set and cemented in a gas well to prevent lost circulation while drilling deeper and to protect strata known or reasonably expected to serve as a source of drinking water for human consumption.

(j) "Tremie pipe" means a pipe or hose used to insert grout into an annular space or to seal gas well.

Subd. 2. **Gas well contractor’s license qualifications**. (a) A person must meet the requirements of a gas well contractor’s license, under section 103I.706, subdivision 4, and fee, under section 103I.706, subdivision 2, item a, to supervise and oversee regulated work on gas wells.

(b) A certified representative must be a professional engineer or geoscientist licensed under sections 326.02 to 326.15 or a professional geologist certified by the American Institute of Professional Geologists.

Subd. 3. **Gas well construction notification requirements**. (a) a gas well contractor must file a gas well notification, under section 103I.706, subdivision 5, and fee, under section 103I.706, subdivision 2, item e.

(b) A gas well construction notification is valid for 18 months.

(c) A new notification must be filed with the commissioner if:

(i) a gas well contractor other than the one listed on the original notification constructs the gas well;

(ii) the gas well is completed on a property other than that listed in the original notification;

(iii) a gas well will be deepened or have casing installed or removed below the frost line.

(d) A person intending to construct a gas well must notify the commissioner at least 24 hours prior to:

(i) beginning of gas well construction;

(ii) setting casing; and

(iii) placing grout.

Subd. 4. **Injection prohibited**. A gas well must not be used to inject or dispose surface water, groundwater, or any other liquid, gas, or chemical. This does not prohibit the injection:

(a) of approved drilling fluids as provided in Subd. 7, or

(b) if a Class 2 injection well permit is obtained for a gas well, as authorized by the Environmental Protection Agency.

Subd. 5. **Hydraulic fracturing treatment prohibited.** Hydraulic fracturing treatment is prohibited in a gas well until the commissioner adopts rules. The commissioner must consider authorization of hydraulic fracturing during rulemaking.

Subd. 6. **Disposal of material.** Drilling fluid, cuttings, treatment chemicals, and discharge water must be:

(a) containerized;

(b) disposed of off-site or obtain a Class 2 injection well permit, authorized by the Environmental Protection Agency; and,

(c) disposed of according to federal, state, and local requirements.

Subd. 7. **Drilling fluids.** (a) Drilling fluids used for a gas well must be water or air based. Water must come from a potable water system and contain a free chlorine residual at all times.

(b) Drilling fluid additives must meet the requirements of ANSI/NSF Standard 60.

Subd.8. **Casing and grout.** (a) Casing for a gas well must be steel casing that meets API Specification 5CT and is of appropriate grade for the pressures and conditions. Casing installed for the construction of a gas well must be new casing. Casing must be marked by the manufacturer according to API Specification 5CT.

(b) Centralizers must be installed at a minimum of 20-foot interval on the casing.

(c) A blowout preventer that is appropriate for the gas pressures expected must be installed on the casing during all drilling after a surface casing has been installed.

(d) Casing offsets are prohibited.

(e) Casing must not be driven.

(f) The diameter of the drilled hole in which surface casing will be set must be least 1.5 inches greater than the nominal outside diameter of the casing that will be installed. All other casings must have at least 0.84 inches between the nominal outside diameter of the casing being cemented and the previously set casing's inside nominal diameter.

(g) A gas well must be cased and grouted to prevent migration of gas and water from one formation to another. During drilling, drilling fluids must be monitored continuously for the presence of gas. Casing must be set to the depth of first detection of gas and grouted from the bottom of the casing up to the established ground surface with neat cement grout.

(h) Neat cement grout must be used for all grouting.

(i) Grouting must start immediately on completion of drilling.

(j) Grout must be pumped into the annular space from the bottom up through the casing, drill rods, or a tremie pipe. Neat cement grout must be allowed to set a minimum of 24 hours. Rapid setting cement must be allowed to set a minimum of 12 hours. Drilling is prohibited during the time the cement is setting.

(k) The annular space between an inner casing and an outer casing must be grouted for its entire length by pumping neat cement grout through a tremie pipe, a drill rod, or the casing. Neat cement grout must be allowed to set a minimum of 24 hours. Rapid setting cement must be allowed to set a minimum of 12 hours. Drilling is prohibited during the time the cement is setting.

(l) The casing of, or inner casing of a multi-cased gas well must extend vertically at least one foot above the established ground surface and at least five feet above the regional flood level. The established ground surface immediately adjacent to the casing must be graded to divert water away from the casing. Termination of the top of the casing below the established ground surface, such as in a vault or pit, is prohibited. Outer casing(s) must terminate no less than 4 feet below the established ground surface.

(m) The casing of a gas well must be covered with a threaded or bolted and flanged gas tight cover equivalent to the casing in weight and strength.

(n) The casing of a gas well must be protected by placing three posts at least four inches square or four inches in diameter around the boring at equal distances from each other and two feet from the gas well. The posts must extend two feet above the established ground surface and four feet below the established ground surface, or to a depth of two feet if each post is set in concrete to a depth of two feet. The posts must be made of reinforced concrete, decay-resistant wood, or schedule 40 steel pipe. Steel pipe must be covered with an overlapping, threaded, or welded steel or iron cap or be filled with concrete or cement.

Subd. 9. **Isolation Distance**. A person must not place, construct, or install a gas well less than 500 feet from a residential building; 500 feet from a water supply well; or 2000 feet from a school facility or childcare center.

Subd. 10. **Groundwater protection.** (a) During the drilling and sealing process, the gas well shall be constructed and maintained to prevent the introduction of surface contaminants into the well and to prevent the passage of water from one aquifer to another; and covered and protected to prevent vandalism or entry of debris into the well.

(b) A gas well must not be constructed to interconnect aquifers separated by a confining layer.

Subd. 11. **Sealing gas wells.** (a) A gas well contractor must file a notification, under section 103I.706, subdivision 8, and fee, under section 103I.706, subdivision 2, to the commissioner.

(b) A gas well sealing notification is valid for 18 months.

(c) A new sealing notification must be filed with the commissioner if a gas well contractor other than the one listed on the original notification will seal the gas well.

(d) The gas well contractor must notify the commissioner of health:

(i) after receiving authorization from the department of natural resources to decommission a gas well; and

(ii) at least 24 hours prior to the start of sealing the gas well.

(e) Materials, debris, and obstructions that may interfere with sealing must be removed from the gas well.

(f) A gas well must be sealed by filling the gas well, including any open annular space, with neat cement grout. The grout must be pumped through a tremie pipe or the casing from the bottom of the gas well or annular space upward to within two feet of the established ground surface. The bottom of the tremie pipe must remain submerged in grout while grouting.

(g) Open annular space surrounding a casing must be grouted by:

(i) filling the annular space with grout according to item (iii);

(ii) removing the casing and filling the well with grout. If casing is to be removed from a collapsing formation, grout must be inserted so the bottom of the casing remains submerged in grout;

(iii) perforating the casing with a minimum of one 1/2-square-inch hole in each foot of casing and forcing grout through the perforations; or

(iv) ripping a minimum of five feet of casing for every 20 feet of casing and forcing grout through the ripped casing, except that casing must be ripped through the entire length of a confining layer.

(h) The gas resource development permittee must have a licensed gas well contractor seal a gas well if:

(i) the gas well contributes to the spread of contamination;

(ii) the gas well was attempted to be sealed but was not sealed according to the provisions of this chapter; or

(iii) the gas well is located, constructed, or maintained in a manner that its continued use or existence endangers groundwater quality or is a safety or health hazard.

(i) The licensed gas well contractor must seal the gas well consistent with provisions of this chapter.

Subd.12. **Rules.** A person requesting to construct a gas well must comply with Minnesota Statutes, section 103I.707 until permanent rules for gas wells adopted by the commissioner are published in the State Register.

EFFECTIVE DATE. This section is effective the day after final enactment and expires on December 31 of the year that the permanent rules are adopted pursuant to 103I.706.

103I.708. OIL WELLS. A person shall not explore, prospect, or construct an oil well until an environmental review has been completed and a production permit has been obtained from the commissioner of natural resources.

EFFECTIVE DATE. This section is effective the day following final enactment.

116D.04 ENVIRONMENTAL IMPACT STATEMENTS

Subd. 16a. **Gas resource development projects. (a)** Until a final rule is adopted addressing environmental review of gas resource development projects, an environmental assessment worksheet must be prepared for any gas resource development project for which a permit is required by section 93.513 subdivision 1 following the process in the environmental quality board's rules adopted under section 116D.04. The Department of Natural Resources is the responsible governmental unit.

(b) 116D.04 Subd. 16a. (b) In addition to publishing and distributing an EAW in accordance with 4410.1500, the RGU for any gas resource development project must also include Minnesota Tribal governments as identified in section 10.65.

Section __. Minnesota Statutes 2024, section 272.02, subdivision 97 is amended to read:

Subd. 97. **Property used in business of mining subject to gross proceeds tax.** The following property used in the business of mining that is subject to the gross proceeds tax under section 298.015 is exempt:

(1) deposits of ores, metals, ~~and~~ minerals, gas, and oil, and the lands in which they are contained;

(2) all real and personal property used in mining, quarrying, producing, or refining ores, minerals, ~~or~~ metals, gas, or oil, including lands occupied by or used in connection with the mining, quarrying, production, or ore refining facilities; and

(3) concentrate.

This exemption applies for each year that a person subject to tax under section 298.015 uses the property for mining, quarrying, producing, or refining ores, metals, ~~or~~ minerals, gas, or oil.

EFFECTIVE DATE. This section is effective for assessment year 2025 and thereafter.

Section __. Minnesota Statutes 2024, section 272.03, subdivision 1 is amended to read:

Subdivision 1. **Real property.** (a) For the purposes of taxation, but not for chapter 297A, "real property" includes the land itself, rails, ties, and other track materials annexed to the land, and all buildings, structures, and improvements or other fixtures on it, bridges of bridge companies, and all rights and privileges belonging or appertaining to the land, and all mines, iron ore and taconite minerals not otherwise exempt, quarries, fossils, and trees on or under it.

(b) A building or structure shall include the building or structure itself, together with all improvements or fixtures annexed to the building or structure, which are integrated with and of permanent benefit to the building or structure, regardless of the present use of the building, and which cannot be removed without substantial damage to itself or to the building or structure.

(c)(i) Real property does not include tools, implements, machinery, and equipment attached to or installed in real property for use in the business or production activity conducted thereon, regardless of size, weight or method of attachment, and mine shafts, tunnels, and other underground openings used to extract ores, ~~and~~ minerals, metals, gas, or oil taxed under chapter 298 together with steel, concrete, and other materials used to support such openings.

(ii) The exclusion provided in clause (i) shall not apply to machinery and equipment includable as real estate by paragraphs (a) and (b) even though such machinery and equipment is used in the business or production activity conducted on the real property if and to the extent such business or production activity consists of furnishing services or products to other buildings or structures which are subject to taxation under this chapter.

(iii) The exclusion provided in clause (i) does not apply to the exterior shell of a structure which constitutes walls, ceilings, roofs, or floors if the shell of the structure has structural, insulation, or temperature control functions or provides protection from the elements, unless the structure is primarily used in the production of biofuels, wine, beer, distilled beverages, or dairy products. Such an exterior shell is included in the definition of real property even if it also has special functions distinct from that of a building, or if such an exterior shell is primarily used for the storage of ingredients or materials used in the production of biofuels, wine, beer, distilled beverages, or dairy products, or for the storage of finished biofuels, wine, beer, distilled beverages, or dairy products.

(d) The term real property does not include tools, implements, machinery, equipment, poles, lines, cables, wires, conduit, and station connections which are part of a telephone communications system, regardless of attachment to or installation in real property and regardless of size, weight, or method of attachment or installation.

<u>**EFFECTIVE DATE.** This section is effective for assessment year 2025 and thereafter.</u>

Section __. Minnesota Statutes 2024, section 273.12, is amended to read:

273.12 ASSESSMENT OF REAL PROPERTY.

It shall be the duty of every assessor and board, in estimating and determining the value of lands for the purpose of taxation, to consider and give due weight to every element and factor affecting the market value thereof, including its location with reference to roads and streets and the location of roads and streets thereon or over the same, and to take into consideration a reduction in the acreage of each tract or lot sufficient to cover the amount of land actually used for any improved public highway and the reduction in area of land caused thereby. It shall be the duty of every assessor and board, in estimating and determining the value of lands for the purpose of taxation, to consider and give due weight to lands which are comparable in character, quality, and location, to the end that all lands similarly located and improved will be assessed upon a uniform basis and without discrimination and, for agricultural lands, to consider and give recognition to its earning potential as measured by its free market rental rate.

When mineral, clay, or gravel deposits exist on a property, and their extent, quality, and costs of extraction are sufficiently well known so as to influence market value, such deposits shall be recognized in valuing the property; except for mineral and energy-resource deposits, <u>metals, gas, and oil</u> which are subject to taxation under section 298.015, and except for taconite and iron-sulphide deposits which are exempt from the general property tax under section 298.25.

<u>**EFFECTIVE DATE.** This section is effective for assessment year 2025 and thereafter.</u>

Section __. Minnesota Statutes 2024, section 289A.02, subdivision 6 is amended to read:

Subd. 6. <u>**Mining company**</u>. "Mining company" means a person engaged in the business of mining or producing ores, <u>minerals, metals, gas, or oil</u> in Minnesota subject to the taxes imposed by section 298.01 or 298.015.

<u>**EFFECTIVE DATE.** This section is effective for taxable years beginning after December 31, 2024.</u>

Section __. Minnesota Statutes 2024, section 289A.12, is amended to add a new subdivision to read:

Subd. 19. **Information report by mining companies.** (a) A mining company required to file an annual tax return under section 289A.08, subdivision 15, for the payment of taxes imposed under section 298.015, must also file an annual information report with the commissioner containing the following information: (1) sales used to compute gross proceeds under section 298.016; (2) the location of the mine or well where the ore, mineral, metal, gas, or oil product is mined, extracted, refined or produced that is used to compute gross proceeds under section 298.016; and (3) other information necessary to collect tax under section 298.015 and to distribute the tax proceeds under section 298.018. The commissioner shall prescribe the content, format, and manner of the annual information report. The annual information report must be filed using a form prescribed by the commissioner. The annual information report must be filed on or before May 1 following the close of the calendar year.
(b) The extension of time provided in section 289A.19, subdivision 2, for the filing of the annual tax return required under section 289A.08, subdivision 15, does not apply to the filing of the annual information report.

EFFECTIVE DATE. This section is effective for annual information reports due after December 31, 2024.

Section __. Minnesota Statutes 2024, section 289A.19, subdivision 2 is amended to read:

Subd. 2. **Corporate franchise and mining company taxes.** (a) Except as provided in clause (b), ~~C~~corporations or mining companies shall receive an extension of seven months or the amount of time granted by the Internal Revenue Service, whichever is longer, for filing the return of a corporation subject to tax under chapter 290 or for filing the return of a mining company subject to tax under sections 298.01 and 298.015. Interest on any balance of tax not paid when the regularly required return is due must be paid at the rate specified in section 270C.40, from the date such payment should have been made if no extension was granted, until the date of payment of such tax.
If a corporation or mining company does not:

(1) pay at least 90 percent of the amount of tax shown on the return on or before the regular due date of the return, the penalty prescribed by section 289A.60, subdivision 1, shall be imposed on the unpaid balance of tax; or

(2) pay the balance due shown on the regularly required return on or before the extended due date of the return, the penalty prescribed by section 289A.60, subdivision 1, shall be imposed on the unpaid balance of tax from the original due date of the return.

(b) If a mining company does not file the annual information report required under section 289A.12, subdivision 19, by May 1 following the close of the calendar year, then the mining company subject to tax under section 298.015 shall not receive the extension of time for filing its annual tax return.

EFFECTIVE DATE. This section is effective for annual information reports due after December 31, 2024.

Section __. Minnesota Statutes 2024, section 290.0134, subdivision 9, is amended to read:

Subd. 9. **Exempt mining and production income.** Income or gains from the business of mining, ~~and~~or the production of gas or oil, as defined in section 290.05, subdivision 1, clause (a), that are not subject to Minnesota franchise tax are a subtraction.

EFFECTIVE DATE. This section is effective for taxable years beginning after December 31, 2024.

Section __. Minnesota Statutes 2024, section 290.0135, is amended to read:

290.0135 BASIS MODIFICATIONS AFFECTING GAIN OR LOSS ON DISPOSITION OF PROPERTY.

(a) For individuals, estates, and trusts, the basis of property is its adjusted basis for federal income tax purposes except as set forth in paragraphs (e) and (f). For corporations, the basis of property is its adjusted basis for federal income tax purposes, without regard to the time when the property became subject to tax under this chapter or to whether out-of-state losses or items of tax preference with respect to the property were not deductible under this chapter, except that the modifications to the basis for federal income tax purposes set forth in paragraphs (b) to (i) are allowed to corporations, and the resulting modifications to federal taxable income must be made in the year in which gain or loss on the sale or other disposition of property is recognized.

(b) The basis of property shall not be reduced to reflect federal investment tax credit.

(c) For property acquired before January 1, 1933, the basis for computing a gain is the fair market value of the property as of that date. The basis for determining a loss is the cost of the property to the taxpayer less any depreciation, amortization, or depletion, actually sustained before that date. If the adjusted cost exceeds the fair market value of the property, then the basis is the adjusted cost regardless of whether there is a gain or loss.

(d) The basis is reduced by the allowance for amortization of bond premium if an election to amortize was made pursuant to Minnesota Statutes 1986, section 290.09, subdivision 13, and the allowance could have been deducted by the taxpayer under this chapter during the period of the taxpayer's ownership of the property.

(e) For assets placed in service before January 1, 1987, corporations, partnerships, or individuals engaged in the business of mining or producing minerals, metals, gas, oil, or ores, other than iron ore or taconite concentrates, subject to the occupation tax under chapter 298 must use the occupation tax basis of property used in that business.

(f) For assets placed in service before January 1, 1990, corporations, partnerships, or individuals engaged in the business of mining iron ore or taconite concentrates subject to the occupation tax under chapter 298 must use the occupation tax basis of property used in that business.

(g) In applying the provisions of sections 301(c)(3)(B), 312(f) and (g), and 316(a)(1) of the Internal Revenue Code, the dates December 31, 1932, and January 1, 1933, shall be substituted for February 28, 1913, and March 1, 1913, respectively.

(h) In applying the provisions of section 362(a) and (c) of the Internal Revenue Code, the date December 31, 1956, shall be substituted for June 22, 1954.

(i) The basis of property shall be increased by the amount of intangible drilling costs not previously allowed due to differences between this chapter and the Internal Revenue Code.

(j) The adjusted basis of any corporate partner's interest in a partnership is the same as the adjusted basis for federal income tax purposes modified as required to reflect the basis modifications set forth in paragraphs (b) to (i). The adjusted basis of a partnership in which the partner is an individual, estate, or trust is the same as the adjusted basis for federal income tax purposes modified as required to reflect the basis modifications set forth in paragraphs (e) and (f).

(k) The modifications contained in paragraphs (b) to (i) also apply to the basis of property that is determined by reference to the basis of the same property in the hands of a different taxpayer or by reference to the basis of different property.

EFFECTIVE DATE. This section is effective for taxable years beginning after December 31, 2024.

Section __. Minnesota Statutes 2024, section 290.05, subdivision 1, is amended to read:

Subdivision 1. **Exempt entities.** The following corporations, individuals, estates, trusts, and organizations shall be exempted from taxation under this chapter, provided that every such person or corporation claiming exemption under this chapter, in whole or in part, must establish to the satisfaction of the commissioner the taxable status of any income or activity:

(a) corporations, individuals, estates, and trusts engaged in the business of mining or producing iron ore, ~~and~~ or mining, producing, or refining other ores, metals, and minerals, or the production of gas or oil, the mining, production, or refining of which is subject to the occupation tax imposed by section 298.01; but if any such corporation, individual, estate, or trust engages in any other business or activity or has income from any property not used in such business it shall be subject to this tax computed on the net income from such property or such other business or activity. Royalty shall not be considered as income from the business of mining or producing iron ore, or mining, producing, or refining other ores, metals and minerals, or the production of gas or oil, within the meaning of this section;

(b) the United States of America, the state of Minnesota or any political subdivision of either agencies or instrumentalities, whether engaged in the discharge of governmental or proprietary functions; and

(c) any insurance company, other than a disqualified captive insurance company.

EFFECTIVE DATE. This section is effective for taxable years beginning after December 31, 2024.

Section __. Minnesota Statutes 2024, section 290.923, subdivision 1, is amended to read:

Subdivision 1. **Definition**. In this section, "royalty" means the amount in money or value of property received by any person having any right, title, or interest in any tract of land in this state for permission to explore, mine, take out, and remove ore, mineral, metal, gas, or oil from the land.

EFFECTIVE DATE. This section is effective for taxable years beginning after December 31, 2024.

Section __. Minnesota Statutes 2024, section 297A.68, subdivision 5, is amended to read:

Subd. 5. **Capital equipment.** (a) Capital equipment is exempt.
"Capital equipment" means machinery and equipment purchased or leased, and used in this state by the purchaser or lessee primarily for manufacturing, fabricating, mining, or refining tangible personal property to be sold ultimately at retail if the machinery and equipment are essential to the integrated production process of manufacturing, fabricating, mining, or refining. Capital equipment also includes machinery and equipment used primarily to electronically transmit results retrieved by a customer of an online computerized data retrieval system.
(b) Capital equipment includes, but is not limited to:

(1) machinery and equipment used to operate, control, or regulate the production equipment;

(2) machinery and equipment used for research and development, design, quality control, and testing activities;

(3) environmental control devices that are used to maintain conditions such as temperature, humidity, light, or air pressure when those conditions are essential to and are part of the production process;

(4) materials and supplies used to construct and install machinery or equipment;

(5) repair and replacement parts, including accessories, whether purchased as spare parts, repair parts, or as upgrades or modifications to machinery or equipment;

(6) materials used for foundations that support machinery or equipment;

(7) materials used to construct and install special purpose buildings used in the production process;

(8) ready-mixed concrete equipment in which the ready-mixed concrete is mixed as part of the delivery process regardless if mounted on a chassis, repair parts for ready-mixed concrete trucks, and leases of ready-mixed concrete trucks; and

(9) machinery or equipment used for research, development, design, or production of computer software.

(c) Capital equipment does not include the following:

(1) motor vehicles taxed under chapter 297B;

(2) machinery or equipment used to receive or store raw materials;

(3) building materials, except for materials included in paragraph (b), clauses (6) and (7);

(4) machinery or equipment used for nonproduction purposes, including, but not limited to, the following: plant security, fire prevention, first aid, and hospital stations; support operations or administration; pollution control; and plant cleaning, disposal of scrap and waste, plant communications, space heating, cooling, lighting, or safety;

(5) farm machinery and aquaculture production equipment as defined by section 297A.61, subdivisions 12 and 13;

(6) machinery or equipment purchased and installed by a contractor as part of an improvement to real property;

(7) machinery and equipment used by restaurants in the furnishing, preparing, or serving of prepared foods as defined in section 297A.61, subdivision 31;

(8) machinery and equipment used to furnish the services listed in section 297A.61, subdivision 3, paragraph (g), clause (6), items (i) to (vi) and (viii);

(9) machinery or equipment used in the transportation, transmission, or distribution of petroleum, liquefied gas, natural gas, water, or steam, in, by, or through pipes, lines, tanks, mains, or other means of transporting those products. This clause does not apply to machinery or equipment used to blend petroleum or biodiesel fuel as defined in section 239.77; or

(10) any other item that is not essential to the integrated process of manufacturing, fabricating, mining, or refining.

(d) For purposes of this subdivision:

(1) "Equipment" means independent devices or tools separate from machinery but essential to an integrated production process, including computers and computer software, used in operating, controlling, or regulating machinery and equipment; and any subunit or assembly comprising a component of any machinery or accessory or attachment parts of machinery, such as tools, dies, jigs, patterns, and molds.

(2) "Fabricating" means to make, build, create, produce, or assemble components or property to work in a new or different manner.

(3) "Integrated production process" means a process or series of operations through which tangible personal property is manufactured, fabricated, mined, or refined. For purposes of this clause, (i) manufacturing begins with the removal of raw materials from inventory and ends when the last process prior to loading for shipment has been completed; (ii) fabricating begins with the removal from storage or inventory of the property to be assembled, processed, altered, or modified and ends with the creation or production of the new or changed product; (iii) mining begins with the removal of overburden from the site of the ores, minerals, stone, peat deposit, <u>metal, gas, oil,</u> or surface materials and ends when the last process before stockpiling is completed; and (iv) refining begins with the removal from inventory or storage of a natural resource and ends with the conversion of the item to its completed form.

(4) "Machinery" means mechanical, electronic, or electrical devices, including computers and computer software, that are purchased or constructed to be used for the activities set forth in paragraph (a), beginning with the removal of raw materials from inventory through completion of the product, including packaging of the product.

(5) "Machinery and equipment used for pollution control" means machinery and equipment used solely to eliminate, prevent, or reduce pollution resulting from an activity described in paragraph (a).

(6) "Manufacturing" means an operation or series of operations where raw materials are changed in form, composition, or condition by machinery and equipment and which results in the production of a new article of tangible personal property. For purposes of this subdivision, "manufacturing" includes the generation of electricity or steam to be sold at retail.

(7) "Mining" means the extraction of minerals, ores, stone, ~~or~~ peat<u>, metal, gas, or oil. Gas and oil shall have the meaning given to those terms in section 298.001, subdivisions 14 and 15.</u>

(8) "Online data retrieval system" means a system whose cumulation of information is equally available and accessible to all its customers.

(9) "Primarily" means machinery and equipment used 50 percent or more of the time in an activity described in paragraph (a).

(10) "Refining" means the process of converting a natural resource to an intermediate or finished product, including the treatment of water to be sold at retail.

(11) This subdivision does not apply to telecommunications equipment as provided in subdivision 35a, and does not apply to wire, cable, or poles for telecommunications services.

EFFECTIVE DATE. This section is effective for sales and purchases made after December 31, 2024.

Section __. Minnesota Statutes 2024, section 297A.71, subdivision 14, is amended to read:

Subd. 14. **Mineral production facilities.** Building materials, equipment, and supplies used for the construction of the following mineral production facilities are exempt.
The mineral production facilities that qualify for this exemption are:
(1) a value added iron products plant, which may be either a new plant or a facility incorporated into an existing plant that produces iron upgraded to a minimum of 75 percent iron content or any iron alloy with a total minimum metallic content of 90 percent;
(2) a facility used for the manufacture of fluxed taconite pellets as defined in section 298.24;
(3) a new capital project that has a total cost of over $40,000,000 that is directly related to production, cost, or quality at an existing taconite facility that does not qualify under clause (1) or (2); and
(4) a new mine or minerals processing plant for any mineral, ore, metal, gas, or oil subject to the gross proceeds tax imposed under section 298.015.
The tax must be imposed and collected as if the rate under section 297A.62, subdivision 1, applied, and then refunded in the manner provided in section 297A.75.

EFFECTIVE DATE. This section is effective for sales and purchases made after December 31, 2024.

Section __. Minnesota Statutes 2024, section 298.001, subdivision 3a is amended to read:

Subd. 3a. **Producer**. "Producer" means a person engaged in the business of mining or producing iron ore, taconite concentrate, ~~or~~ direct reduced ore, other ore, minerals, metals, gas, or oil in this state.

EFFECTIVE DATE. This section is effective for taxable years beginning after December 31, 2024.

Section __. Minnesota Statutes 2024, section 298.001, is amended to add a subdivision to read:

Subd. 10a. **Producing.** "Producing" means and is limited to producing:
(1) of gas or oil products, the drilling, extracting, separating, or beneficiating of which are subject to tax under section 298.015; and

(2) carried out by the entity, or affiliated entity, that drilled, extracted, separated, or beneficiating the gas or oil products.

EFFECTIVE DATE. This section is effective for taxable years beginning after December 31, 2024.

Section __. Minnesota Statutes 2024, section 298.001, is amended by adding a subdivision to read:

Subd. 14. **Gas.** "Gas" means all gases, both hydrocarbon and nonhydrocarbon, that occur naturally beneath the earth's surface in Minnesota. "Gas" includes, but is not limited to, natural gas, hydrogen, carbon dioxide, nitrogen, hydrogen sulfide, helium, methane and a mixture of some or all of these gases.

EFFECTIVE DATE. This section is effective for taxable years beginning after December 31, 2024.

Section __. Minnesota Statutes 2024, section 298.001, is amended by adding a subdivision to read:

Subd. 15. **Oil.** "Oil" means all oils that occur naturally beneath the earth's surface in Minnesota. "Oil" includes, but is not limited to, petroleum, crude oil, condensate, casinghead gasoline, or other mineral oils and a mixture of some or all of these oils.

EFFECTIVE DATE. This section is effective for taxable years beginning after December 31, 2024.

Section __. Minnesota Statutes 2024, section 298.001, is amended by adding a subdivision to read:

Subd. 16. **Gas or Oil Production.** "Gas or oil production," "the production of gas or oil," and "producing gas or oil" mean the action of taking gas or oil, in its natural state, out from beneath the earth's surface in Minnesota and includes drilling, extracting, separating or beneficiating such gas or oil in Minnesota.

EFFECTIVE DATE. This section is effective for taxable years beginning after December 31, 2024.

Section __. Minnesota Statutes 2024, section 298.01, subdivision 3, is amended to read:

Subd. 3. **Occupation tax; other ores; gas and oil.** Every person engaged in the business of mining, refining, or producing ores, metals, or minerals, or producing gas or oil, in this state, when such resources are extracted, in their natural state, from beneath the surface of the earth in Minnesota, except iron ore or taconite concentrates, shall pay an occupation tax to the state of Minnesota as provided in this subdivision. For purposes of this subdivision, mining includes the application of hydrometallurgical processes. Hydrometallurgical processes are processes that extract the ores, metals, or minerals, by use of aqueous solutions that leach, concentrate, and recover the ore, metal, or mineral. The tax is determined in the same manner as the tax imposed by section 290.02, except that sections 290.05, subdivision 1, clause (a), 290.17, subdivision 4, and 290.191, subdivision 2, do not apply, and the occupation tax must be computed by applying to taxable income the rate of 2.45 percent.

The tax is in addition to all other taxes.

EFFECTIVE DATE. This section is effective for taxable years beginning after December 31, 2024.

Section __. Minnesota Statutes 2024, section 298.01, subdivision 3a, is amended to read:

Subd. 3a. **Gross income.** (a) For purposes of determining a person's taxable income under subdivision 3, gross income is determined by the amount of gross proceeds from mining, refining or producing of other ores, metals, minerals, gas, or oil, in ~~this state~~ Minnesota under section 298.016 and includes any gain or loss recognized from the sale or disposition of assets used in the business in this state. If more than one ore, mineral, ~~or~~ metal, gas, or oil referred to in section 298.016 is mined~~and processed~~ or produced at the same mine, well, and plant, a gross income for each ore, mineral, ~~or~~ metal, gas, or oil must be determined separately. The gross incomes may be combined on one occupation tax return to arrive at the gross income of all production.

(b) In applying section 290.191, subdivision 5, transfers of ores, metals, ~~or~~ minerals, gas, or oil that are subject to tax under this chapter are deemed to be sales in this state.

EFFECTIVE DATE. This section is effective for taxable years beginning after December 31, 2024.

Section __. Minnesota Statutes 2024, section 298.01, subdivision 3b, is amended to read:

Subd. 3b. **Deductions.** (a) For purposes of determining taxable income under subdivision 3, the deductions from gross income include only those expenses necessary to convert raw ores, metals, minerals, gas, or oil to marketable quality. Such expenses include costs associated with refinement but do not include expenses such as transportation, stockpiling, marketing, or marine insurance that are incurred after marketable ores, metals, minerals, gas, or oil are produced, unless the expenses are included in gross income. The allowable deductions from a mine, well, or plant that mines and produces more than one ore, mineral, metal, ~~or~~ energy resource, gas, or oil must be determined separately for the purposes of computing the deduction in section 290.0133, subdivision 9. These deductions may be combined on one occupation tax return to arrive at the deduction from gross income for all production.

(b) The provisions of sections 290.0133, subdivisions 7 and 9, and 290.0134, subdivisions 7 and 9, are not used to determine taxable income.

EFFECTIVE DATE. This section is effective for taxable years beginning after December 31, 2024.

Section __. Minnesota Statutes 2024, section 298.01, subdivision 4a, is amended to read:

Subd. 4a. **Gross income.** (a) For purposes of determining a person's taxable income under subdivision 4, gross income is determined by the mine value of the ore mined in Minnesota and includes any gain or loss recognized from the sale or disposition of assets used in the business in this state.

(b) Mine value is the value, or selling price, of iron ore or taconite concentrates, f.o.b. mine. The mine value is calculated by multiplying the iron unit price for the period, as determined by the commissioner, by the tons produced and the weighted average analysis.

(c) In applying section 290.191, subdivision 5, transfers of iron ore and taconite concentrates are deemed to be sales in this state.

(d) If iron ore, ~~or~~ taconite and ~~a~~an other ore, ~~and a~~ mineral, ~~or~~ metal, ~~or~~energy resource, gas, or oil, referred to in section 298.016 is mined ~~and~~or produced at the same mine and plant, a gross income for each other ore, mineral, metal, ~~or~~energy resource, gas, or oil must be determined separately from the mine value for the iron ore or taconite. The gross income may be combined on one occupation tax return to arrive at the gross income from all production.

EFFECTIVE DATE. This section is effective for taxable years beginning after December 31, 2024.

Section __. Minnesota Statutes 2024, section 298.01, subdivision 4b, is amended to read:

Subd. 4b. **Deductions.** For purposes of determining taxable income under subdivision 4, the deductions from gross income include only those expenses necessary to convert raw iron ore or taconite concentrates to marketable quality. Such expenses include costs associated with beneficiation and refinement but do not include expenses such as transportation, stockpiling, marketing, or marine insurance that are incurred after marketable iron ore or taconite pellets are produced. The allowable deductions from a mine, well, or plant that mines and produces iron ore or taconite and one or more mineral, ~~or~~ metal, gas or oil referred to in section 298.016 must be determined separately for the purposes of computing the deduction in section 290.0133, subdivision 9. These deductions may be combined on one occupation tax return to arrive at the deduction from gross income for all production.

EFFECTIVE DATE. This section is effective for taxable years beginning after December 31, 2024.

Section __. Minnesota Statutes 2024, section 298.01, subdivision 5, is amended to read:

Subd. 5. **If declared unconstitutional.** If the taxes imposed in subdivisions 3 and 4 are found unconstitutional by any court of last resort, then persons engaged in the business of mining or producing iron ore, or other ores, metals, minerals, gas, or oil shall pay the occupation tax imposed in Minnesota Statutes 1986, chapter 298. For purposes of applying Minnesota Statutes 1986, chapter 298, the term “other ores” as used in that chapter includes ores other than iron ore as well as minerals, metals, gas or oil.

EFFECTIVE DATE. This section is effective for taxable years beginning after December 31, 2024.

Section __. Minnesota Statutes 2024, section 298.01, subdivision 6, is amended to read:

Subd. 6. **Deductions applicable to mining taconite, and other ores, gas or oil; ratio applied.** If a person is engaged in the business of mining, extracting or producing both iron ores, taconite concentrates, or direct reduced ore, and other ores, minerals, metals, gas or oil from the same mine or facility, that person must separately determine the mine value of (1) the iron ore, taconite concentrates, and direct reduced ore, and (2) the amount of gross proceeds from mining other ores, minerals, metals, gas, or oil in Minnesota. The ratio of mine value from iron ore, taconite concentrates, and direct reduced ore to gross proceeds from mining other ores, minerals, metals, gas or oil must be applied to deductions common to both processes to determine taxable income for tax paid pursuant to subdivisions 3 and 4.

EFFECTIVE DATE. This section is effective for taxable years beginning after December 31, 2024.

Section __. Minnesota Statutes 2024, section 298.015, subdivision 1, is amended to read:

Subdivision 1. **Tax imposed.** (a) Except as provided in clause (b), a~~A~~ person engaged in the business of mining shall pay to the state of Minnesota for distribution as provided in section 298.018 a gross proceeds tax equal to 0.4 percent of the gross proceeds from mining in Minnesota. The tax applies to all ores, metals, ~~and~~ minerals, gas, or oil mined, extracted, produced, or refined within the state of Minnesota, when such resources are extracted, in their natural state, from beneath the surface of the earth in Minnesota, except for sand, silica sand, gravel, building stone, crushed rock, limestone, granite, dimension granite, dimension stone, horticultural peat, clay, soil, iron ore, and taconite concentrates. The tax is in addition to all other taxes provided for by law.

(b) The following tax rates apply to the gas products listed:

(i) % of the gross proceeds for carbon dioxide products;
(ii) % of the gross proceeds for helium products; and
(iii) % of the gross proceeds for hydrogen products.

(c) A person engaged in the business of producing gas or oil in this state is not subject to the minimum payment under subdivision 3.

EFFECTIVE DATE. This section is effective for taxable years beginning after December 31, 2024.

Section __. Minnesota Statutes 2024, section 298.016, is amended to read:

298.016 GROSS PROCEEDS.

Subdivision 1. **Computation; arm's-length transactions.** When a metal ~~or,~~ mineral, gas, or oil product is sold by the producer in an arm's-length transaction, the gross proceeds are equal to the proceeds from the sale of the product. This subdivision applies to sales realized on all metal ~~or~~, mineral, gas, or oil products produced from mining or production, including reduction, beneficiation, or any treatment or process used by a producer to obtain a metal ~~or~~, mineral, gas, or oil product which is commercially marketable.

Subd. 2. **Other transactions.** When a metal ~~or~~, mineral, gas, or oil product is used by the producer or disposed of in a non-arm's-length transaction, the gross proceeds must be determined using the alternative computation in subdivision 3. Transactions subject to this subdivision include, but are not limited to, shipments to a wholly owned smelter, transactions with associated or affiliated companies, and any other transactions which are not at arm's length.

Subd. 3. **Alternative computation.** (a) Except as provided in clause (c), the commissioner of revenue shall determine the alternative computation of gross proceeds using the following procedure:

(1) Metal and mineral prices shall be determined by using the average annual market price as published in the Engineering and Mining Journal;

(2) For metals or mineral products with a monthly or weekly price quotation in the Engineering and Mining Journal, but for which no average annual price has been published, an arithmetic average of the monthly or weekly prices published in the Engineering and Mining Journal shall be used;

(3) If the price of a particular metal or mineral product is not published in the Engineering and Mining Journal, another recognized published price, as established by the commissioner of revenue will be used.

(b) The quantity of each particular metal or mineral product recovered and paid or credited for by the smelter will be multiplied by the average annual market price as determined in clause (a). Special smelter charges for particular metals will be allowed as a deduction from this price. The resulting amount will be the gross proceeds for calculating the tax in section 298.015.

(c) For purposes of determining the alternative computation of gross proceeds for gas or oil products, a recognized published price, as established by the commissioner of revenue will be used. If there is no currently available recognized published price, the commissioner shall determine the fair market value of the gas or oil product using the method described below which results in the greater market value:

(i) A recognized price published historically, as established by the commissioner. The commissioner shall adjust the historical published price for inflation, which adjustment shall be determined as provided in section 270C.22, using the year in which the most recent historical price is published as the statutory year.

(ii) The commissioner may use an arm's length transaction price paid by other parties for gas or oil products of like quantity. The commissioner may adjust this arm's length transaction price to account for differences in quality, recency, inflation, terms and conditions, and other relevant circumstances under which the arm's length transaction price was paid in relation to the non-arm's-length transaction price computed under this subdivision.

EFFECTIVE DATE. This section is effective for taxable years beginning after December 31, 2024.

Section __. Minnesota Statutes 2024, section 298.016, subdivision 4, is amended to read:

Subd. 4. **Metal, ~~or~~mineral, gas, or oil products; definition.** For the purposes of this section, "metal, ~~or~~mineral, gas, or oil products" means all ores, metals, ~~and~~ minerals, gases, or oils subject to the tax provided in section 298.015.

EFFECTIVE DATE. This section is effective for taxable years beginning after December 31, 2024.

Section __. Minnesota Statutes 2024, section 298.016, is amended to add a new subdivision to read:

Subd. 4a. **Gas or oil products; definition.** For purposes of this section, "gas or oil products" mean all gases and oils subject to the tax imposed in section 298.015.

EFFECTIVE DATE. This section is effective for taxable years beginning after December 31, 2024.

Section __. Minnesota Statutes 2024, section 298.018, is amended to read:

Subdivision 1. **Within taconite assistance area.** (a) Except as provided in subdivision 1a, the ~~The~~ proceeds of the tax paid under sections 298.015 and 298.016 on ores, metals, or minerals mined or extracted within the taconite assistance area defined in section 273.1341, shall be allocated as follows:

(1) except as provided under paragraph (b), five percent to the city or town within which the ores, metals, minerals, or energy resources are mined or extracted, or within which the concentrate was produced. If the mining and concentration, or different steps in either process, are carried on in more than one taxing district, the commissioner shall apportion equitably the proceeds among the cities and towns by attributing 50 percent of the proceeds of the tax to the operation of mining or extraction, and the remainder to the production plant or concentrating plant and to the processes of production and concentration, and with respect to each thereof giving due consideration to the relative extent of the respective operations performed in each taxing district;

(2) ten percent to the taconite municipal aid account to be distributed as provided in section 298.282, subdivisions 1 and 2, on the dates provided under this section;

(3) ten percent to the school district within which the ores, metals, minerals, or energy resources are mined or extracted, or within which the concentrate was produced. If the mining, production and concentration, or different steps in ~~either~~ those processes, are carried on in more than one school district, distribution among the school districts must be based on the apportionment formula prescribed in clause (1);

(4) 20 percent to a group of school districts comprised of those school districts wherein the ores, metals, minerals, or energy resources was mined or extracted or in which there is a qualifying municipality as defined by section 273.134, paragraph (b), in direct proportion to school district indexes as follows: for each school district, its pupil units determined under section 126C.05 for the prior school year shall be multiplied by the ratio of the average adjusted net tax capacity per pupil unit for school districts receiving aid under this clause as calculated pursuant to chapters 122A, 126C, and 127A for the school year ending prior to distribution to the adjusted net tax capacity per pupil unit of the district. Each district shall receive that portion of the distribution which its index bears to the sum of the indices for all school districts that receive the distributions;

(5) ten percent to the county within which the ores, metals, minerals ~~or~~ energy resources, oil, or gas are mined or extracted, or within which the concentrate was produced. If the mining, production and concentration, or different steps in ~~either~~ those processes, are carried on in more than one county, distribution among the counties must be based on the apportionment formula prescribed in clause (1), provided that any county receiving distributions under this clause shall pay one percent of its proceeds to the Range Association of Municipalities and Schools;

(6) five percent to St. Louis County acting as the counties' fiscal agent to be distributed as provided in sections 273.134 to 273.136;

(7) 20 percent to the commissioner of Iron Range resources and rehabilitation for the purposes of section 298.22;

(8) three percent to the Douglas J. Johnson economic protection trust fund;

(9) seven percent to the taconite environmental protection fund; and

(10) ten percent to the commissioner of Iron Range resources and rehabilitation for capital improvements to Giants Ridge Recreation Area.

(b) If the ores, metals, minerals, ~~materials~~ or energy resources are mined, extracted, or concentrated in School District No. 2711, Mesabi East, then the amount under paragraph (a), clause (1), must instead be distributed pursuant to this paragraph. The cities of Aurora, Babbitt, Ely, and Hoyt Lakes must each receive 20 percent of the amount. The city of Biwabik and Embarrass Township must each receive ten percent of the amount.

(c) For the first five years that tax paid under section 298.015, subdivisions 1 and 2, is distributed under this subdivision, ten percent of the total proceeds distributed in each year must first be distributed pursuant to this paragraph. The remaining 90 percent of the total proceeds distributed in each of those years must be distributed as outlined in paragraph (a). Of the amount available under this paragraph, the cities of Aurora, Babbitt, Ely, and Hoyt Lakes must each receive 20 percent. Of the amount available under this paragraph, the city of Biwabik and Embarrass Township must each receive ten percent. This paragraph applies only to tax paid under section 298.015, subdivision 1, paragraph (a), by a person engaged in the business of mining within the area described in section 273.1341, clauses (1) and (2).

Subd. 1a. The proceeds of the tax paid under sections 298.015 and 298.016 on gas or oil produced within the taconite assistance area defined in section 273.1341, shall be allocated as follows: ______________.

Subd. 1~~a~~b. **Distribution Date.** The proceeds of the tax allocated under subdivision 1 shall be distributed on December 15 each year. Any payment of proceeds received after December 15 shall be distributed on the next gross proceeds tax distribution date.

Subd. 2. **Outside taconite assistance area.** (a) Except as provided in clause (b), the proceeds of the tax paid under sections 298.015 and 298.016 on ores, metals, or minerals mined or extracted outside of the taconite assistance area defined in section 273.1341, shall be deposited in the general fund.

(b) The proceeds of the tax paid under sections 298.015 and 298.016 on gas or oil produced outside the taconite assistance area defined in section 273.1341, shall be allocated as follows: __________________.

Subd. 1b. **Distribution Date.** The proceeds of the tax allocated under subdivision 2 shall be distributed on December 15 each year. Any payment of proceeds received after December 15 shall be distributed on the next gross proceeds tax distribution date.

EFFECTIVE DATE. This section is effective for taxable years beginning after December 31, 2024.

Section __. Minnesota Statutes 2024, section 298.17, is amended to read:

298.17 OCCUPATION TAXES TO BE APPORTIONED.

(a) All occupation taxes paid by persons, copartnerships, companies, joint stock companies, corporations, and associations, however or for whatever purpose organized, engaged in the business of mining or producing iron ore, ~~or~~ other ores, metals, minerals, gases, or oils, when collected shall be apportioned and distributed in accordance with the Constitution of the state of Minnesota, article X, section 3, in the manner following: 90 percent shall be deposited in the state treasury and credited to the general fund of which four-ninths shall be used for the support of elementary and secondary schools; and ten percent of the proceeds of the tax imposed by this section shall be deposited in the state treasury and credited to the general fund for the general support of the university.

(b) Except as provided in paragraph (e), o~~O~~f the money apportioned to the general fund by this section: (1) there is annually appropriated and credited to the mining environmental and regulatory account in the special revenue fund an amount equal to that which would have been generated by a 2-1/2 cent tax imposed by section 298.24 on each taxable ton produced in the preceding calendar year. Money in the mining environmental and regulatory account is appropriated annually to the commissioner of natural resources to fund agency staff to work on environmental issues and provide regulatory services for ferrous and nonferrous mining <u>and production</u> operations in this state. Payment to the mining environmental and regulatory account shall be made by July 1 annually. The commissioner of natural resources shall execute an interagency agreement with the Pollution Control Agency to assist with the provision of environmental regulatory services such as monitoring and permitting required for ferrous and nonferrous mining <u>and production</u> operations; (2) there is annually appropriated and credited to the Iron Range resources and rehabilitation account in the special revenue fund an amount equal to that which would have been generated by a 1.5 cent tax imposed by section 298.24 on each taxable ton produced in the preceding calendar year, to be expended for the purposes of section 298.22; and (3) there is annually appropriated and credited to the Iron Range resources and rehabilitation account in the special revenue fund for transfer to the Iron Range schools and community development account under section 298.28, subdivision 7a, an amount equal to that which would have been generated by a six cent tax imposed by section 298.24 on each taxable ton produced in the preceding calendar year. Payment to the Iron Range resources and rehabilitation account shall be made by May 15 annually.

(c) The money appropriated pursuant to paragraph (b), clause (2), shall be used (i) to provide environmental development grants to local governments located within any county in region 3 as defined in governor's executive order number 60, issued on June 12, 1970, which does not contain a municipality qualifying pursuant to section 273.134, paragraph (b), or (ii) to provide economic development loans or grants to businesses located within any such county, provided that the county board or an advisory group appointed by the county board to provide recommendations on economic development shall make recommendations to the commissioner of Iron Range resources and rehabilitation regarding the loans. Payment to the Iron Range resources and rehabilitation account shall be made by May 15 annually.

(d) Of the money allocated to Koochiching County, one-third must be paid to the Koochiching County Economic Development Commission.

<u>(e) Of the money apportioned to the general fund under this section, the proceeds of the tax paid under sections 298.01, subdivision 3 on gas or oil produced shall be allocated as follows: ____________________.</u>

<u>EFFECTIVE DATE.</u> <u>This section is effective for taxable years beginning after December 31, 2024.</u>

APPROPRIATION; GAS WELL CONSTRUCTION AND SEALING NOTIFICATION.

$xxx in fiscal year 2026 is appropriated to the commissioner of health for the development of a legislatively-authorized gas well and sealing notification program, rig registration, licensing program, inspection program, rulemaking, credentialing in an information technology system for the electronic submission of gas well records, rig registration, and licensure that accepts online fee payments, issues unique identifiers, ability to retrieve records, and contains a searchable database. This is a onetime appropriation that is available until December 31, 2027.

$xxx annually to the commissioner of health starting in fiscal year 2026 to hire staff who will inspect, enforce, and manage oversight of a legislatively-authorized gas well and sealing notification, licensing, and inspection program in Minnesota. These staff will serve as subject matter experts in gas well construction and sealing of Minnesota's newly discovered gas reserves.

EFFECTIVE DATE. This section is effective the day following final enactment.

APPROPRIATION; GAS EXPLORATION AND PRODUCTION PERMITTING PROGRAM.

$xxx is appropriated annually to the commissioner of natural resources starting in FY26 to hire staff who will start and manage a gas exploration and production permitting program in the state.

EFFECTIVE DATE. This section is effective the day following final enactment.

Appendices

Appendix A: Final Report of Regulatory Best Practices

Appendix B: Compiled Input Categorized by Theme

Appendix C: GTAC Considerations of Thematic Input

Jost Energy Law PC

Williams Weese Pepple & Ferguson

Aota Technical, LLC

Final Report of Best Practices

Regulatory Best Practices

In Support of

Minnesota Gas Technical Advisory Committee (GTAC)

PREPARED FOR:

DeYoung Consulting Services on behalf of GTAC

GTAC Agencies:

Minnesota Department of Natural Resources
Minnesota Department of Revenue
Minnesota Environmental Quality Board
Minnesota Department of Health
Minnesota Pollution Control Agency

PREPARED BY:

Jost Energy Law
Williams Weese Pepple & Ferguson
Aota Technical, LLC

December 2024

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Abbreviations	
API	American Petroleum Institute
AST	Aboveground storage tank
AVO	Audio, visual, olfactory
BLM	Bureau of Land Management
BBLS	Barrels
BOPE	Blowout prevention equipment
CFR	Code of Federal Regulations
CO2	Carbon dioxide
CRS	Colorado Revised Statute
DNR	Minnesota Department of Natural Resources
DOR	Minnesota Department of Revenue
DSU	Drilling Spacing Unit
E&P	Exploration and production
EAW	Environmental Assessment Worksheet
ECMC	Colorado Energy & Carbon Management Commission
EPA	U.S. Environmental Protection Agency
EQB	Minnesota Environmental Quality Board
EUR	Estimated ultimate recovery
GIS	Geographic information system
GTAC	Gas Technical Advisory Committee
H2S	Hydrogen sulfide
JOA	Joint Operating Agreement
MCF	Thousand cubic feet
MDH	Minnesota Department of Health
MPCA	Minnesota Pollution Control Agency
NPDES	National Pollutant Discharge Elimination System
NSPS	New Source Performance Standards
OBA	Other Business Arrangement
PLSS	Public Land Survey System
PSA	Pressure swing adsorption
PSI	Pounds per square inch
POTW	Publicly owned treatment works
PTE	Potential to emit
RCRA	Resource Conservation and Recovery Act
RGU	Responsible Governmental Unit
SITLA	Utah School and Institutional Trust Lands Administration
SUA	Surface Use Agreement
TENORM	Technologically enhanced naturally occurring radioactive material
TPY	Tons per year
UIC	Underground Injection Control
USGS	U.S. Geological Survey
VOC	Volatile organic compounds

Introduction

Background

The Minnesota Gas Resources Technical Advisory Committee (GTAC) formed in response to provisions of Minnesota legislation passed in May 2024. The legislation authorized five Minnesota agencies to adopt or amend rules to govern oil and gas exploration and production in the state. The agencies are:

Department of Natural Resources (DNR)
Department of Health (MDH)
Department of Labor and Industry [supplanted by Department of Revenue (DOR)]
Environmental Quality Board (EQB)
Pollution Control Agency (MPCA)

GTAC convened in July 2024 to initiate work that will culminate in January 2025 with a report to the Minnesota legislature for the 2025 legislative session. The report will provide recommendations and proposed statutory language for a temporary framework to regulate GTAC's first priority: gas resource development in Minnesota. Specifically, GTAC focused on potential for well drilling and production for helium and hydrogen gas, with potential for associated gases, including methane. Preparation of GTAC's report includes public, stakeholder, and tribal input.

Minnesota legislative committees are expected to use the GTAC report, "*Recommendations and Statutory Language for Permitting Gas Resource Development Under a Temporary Regulatory Framework*," as the basis to enact enabling legislation for agencies to regulate gas development pending a subsequent multi-year notice and comment rulemaking, by agency, for the gas industry in Minnesota.

Preparers for the Report of Best Practices

The DNR contracted with DeYoung Consulting Services to provide organizational support to GTAC. DeYoung, on behalf of DNR, subcontracted for oil and gas sector technical support to GTAC during GTAC's development of recommendations to the legislature. The subcontractor was tasked with illuminating state precedents and example best practices for regulation of gas, including helium gas. Information was derived from oil and gas producing states across Midwestern and Rocky Mountain states. Information considered Minnesota's interest in fostering helium development in a manner protective of public health, the environment, and state fiduciary interests.

The technical support team included specialists in the regulation and permitting of helium gas wells, as well as the oil and natural gas industry more broadly. The technical support team's expertise was cross disciplinary. It included legal experts in energy, natural resource, and administrative and regulatory law; rulemaking; and oil and gas leasing, pooling, and unitization. It further included environmental regulatory specialists in regulatory development and compliance; siting; location analysis; and environmental resource analysis for helium gas and the energy sector. The subcontractor organizations are:

Jost Energy Law
Williams Weese Pepple & Ferguson
Aota Technical, LLC

Report Organization

The Report of Best Practices is organized by Minnesota agency and regulatory topic. Regulatory topics were identified in the 2024 Minnesota legislation and subsequent GTAC priorities. Information was provided for GTAC input in stages to identify, describe, research, and document regulatory topics and their context, precedents and examples, citations, and regulatory links. All of the information was derived from oil and gas producing states. The information informs and supports GTAC for GTAC's independent determination of recommendations to make for a temporary regulatory framework in Minnesota.

1.0 Minnesota Department of Natural Resources

Development Permit

1.1 When a Development Permit is Required

1. A Development Permit would be required prior to disturbing a new surface location to drill a gas well or install production equipment related to the gas well.
2. Expanding an existing location would require amendment to an approved Development Permit.
3. Exploration wells would be considered gas wells subject to a Development Permit, regardless of whether the well is used for production.
4. A seismic survey would not require a Development Permit and would be subject to state rules governing seismic surveys.
5. A stratigraphic well would not require a Development Permit and would be subject to state rules governing stratigraphic wells.
6. Either a water well or a stratigraphic well used for exploration or production of gas would require a Development Permit.
7. A stand-alone gas processing operation on a non-contiguous surface location would not require a Development Permit and would be subject to state rules governing industrial facilities.

Based in part on Colorado Energy & Carbon Management Commission, Rule 304.a
https://ecmc.state.co.us/documents/reg/Rules/LATEST/300%20Series%20-%20Permitting%20Process.pdf

1.2 Scope of Operations Subject to a Development Permit

1. Well pad
2. Production equipment on the well pad
3. Access road from the public road to the well pad
4. Flowline from the well pad to processing operations at another location
5. Where:
    a. Well pad is the total area disturbed for the well pad.
    b. Production equipment is surface equipment, and the flowlines on the well pad connecting the surface equipment, during the life of the well or processing operations on the pad.
    c. Flowlines also include the material and disturbance for one or more flowlines from the well pad to processing operations at another location.
    d. Processing operations are equipment to separate, purify, compress, and store gas from the well and any liquids.
    e. Processing operations can be located on the well pad as production equipment.
        1) Processing operations on another non-contiguous surface location off of the well pad would be subject instead to state rules governing industrial facilities.
    f. Pipelines from processing operations at another location would be regulated consistent with regulation of other industrial pipelines in the state.

1.3 Distinguish Surface Location Versus Downhole Operations

1. Surface location would mean the well pad and all area on the surface disturbed for the well pad, access, and flowlines.
2. Downhole operations would mean the subsurface well.
3. Surface location
    a. Colorado refers to an *Oil and Gas Location*. This means a definable area where an operator disturbs the land surface to locate an oil and gas facility. Oil and gas facility consists of equipment for exploration, production, withdrawal, treatment, or processing.
    b. Utah refers to a *Well Site*. This means the area directly disturbed during drilling and subsequent use by production facilities.
    c. Wyoming refers to *Oil and Gas Operations*. This means the surface disturbing activities associated with drilling, producing, and transporting oil and gas, including the full range of development activity from exploration through production and reclamation of the disturbed surface.
4. Well
    a. In Colorado a well means a hole drilled for the purpose of producing oil or gas [including non-hydrocarbon gases such as carbon dioxide (CO2) and helium], a Class II underground injection control (UIC) well, and certain other categories of wells.
    b. In Utah a well means an oil or gas well, or injection or disposal well. It "may not include…seismic, stratigraphic test… or other exploratory holes drilled for the purpose of obtaining geological information only."
    c. In Kansas a well means any hole or penetration of the surface for geological, geophysical, or any oil or gas activity. A gas well means a well that produces gas not associated with oil. Kansas is an example of a state that does not separately define the surface location.

Colorado Energy & Carbon Management Commission, Rule 100
https://ecmc.state.co.us/documents/reg/Rules/LATEST/100%20Series%20-%20Definitions.pdf

Utah Division of Oil, Gas and Mining, Rule 649-1
https://adminrules.utah.gov/public/rule/R649-1/Current%20Rules?searchText=R649

Kansas Corporation Commission, Rule 82-3-101
https://www.kcc.ks.gov/images/PDFs/oil-gas/conservation/cons_rr_091615.pdf

Wyoming Oil & Gas Conservation Commission, Rule 055.0001
https://rules.wyo.gov/Search.aspx?mode=1

1.4 Anticipated Surface Equipment and its Inclusion in Permitting

1. Potential equipment during well drilling and completion:
    a. Drill rig and completion rig
    b. Air package with compressor(s)
    c. Freshwater tank(s)
    d. Formation water tank(s)
    e. Drilling mud tank(s) and pump
    f. Drill cuttings tank(s)
    g. Separator
    h. Portable combustor

i. Pipe rack
j. Fuel tank
k. Light plant
l. Driller's trailer
m. Geology tent or trailer

2. Potential equipment during production

    a. Wellhead
    b. Two-phase separator for gas and water
    c. Produced water storage tank(s)
    d. Secondary containment for produced water storage tank(s)
    e. Combustor
    f. Pressure swing adsorption (PSA) plant

3. Operators can be required to list individual pieces of equipment anticipated to be on site during well drilling and completion.

4. Operators can be required to list individual pieces of equipment anticipated to be on site if the well goes into production.

5. Operators can be required to show the equipment on a layout in plan view or on a drawing.

1.5 Treatment of Production Facility

1. A stand-alone gas processing operation on a non-contiguous surface location would not require a Development Permit and would be subject to state rules governing industrial facilities.

2. Equipment located on the well pad during production would be regulated under the Development Permit as production equipment.

    a. Equipment may include processing operations using a two-phase separator, produced water storage tank(s), and combustor for total gas, and a PSA plant or other processing method for helium.

3. Equipment operation, mechanical integrity, maintenance, and monitoring would be regulated by the Development Permit.

4. Waste disposal would be regulated by PCA, with the option to incorporate waste management, waste disposal, and reporting provisions in the Development Permit.

5. Air emissions would be regulated by PCA through an air permit.

6. Wastewater discharges would be prohibited, with the option to incorporate spill control reporting and control provisions in the Development Permit.

7. Stormwater control would be regulated by PCA consistent with stormwater permit requirements in place in the state.

8. Regarding gas production, in Colorado at Energy & Carbon Management Commission (ECMC) Rule 430, the operator must measure and report the volume of gas produced from the lease or a production unit, measured by meter.

    Colorado Energy & Carbon Management Commission, Rule 100
    https://ecmc.state.co.us/documents/reg/Rules/LATEST/400%20Series%20-%20Operations%20and%20Reporting.pdf

9. Regarding gas *processing*, in Utah at Rule 649-6-1, the operator of a facility in which gas is conditioned for sale must file a monthly form reporting receipt, processing, and disposition of gas.

Utah Division of Oil, Gas and Mining, Rule 649-6-1
https://adminrules.utah.gov/public/rule/R649-6/Current%20Rules?searchText=R649

1.6 Requirement for Methane Gas

1. Separation for gas and any water from the formation (produced water) could occur in a two-phase separator. The separator would be part of production equipment on the well pad or at another location.
    a. Water from the separator could be routed by flowline to an aboveground storage tank for storage, liquids offloading by truck, and disposal.
    b. Total gas from the separator could be routed by flowline to a PSA plant.
    c. Separation of component gases would occur at that PSA plant.
    d. Operations may demonstrate, for example, that hydrocarbons (as methane) represent less than 5 percent of the total gas stream.
    e. Other components are likely to be helium, CO2, nitrogen, and trace gases (e.g., argon).
2. At low volumes, methane would not be expected to support a commercial pipeline for takeaway. Methane with no pipeline takeaway may be referred to as “stranded gas.”
3. Methane with no pipeline takeaway potentially can route for destruction to an enclosed combustor. The enclosed combustor would be expected to have a destruction efficiency of at least 98 percent.
    a. If supplemental fuel is required to operator the combustor, beneficial use or venting could be considered.
4. Methane with no pipeline takeaway can route for beneficial use on site as a fuel source for production equipment, where:
    a. Methane provides supply gas for the two-phase separator.
    b. Methane provides supply gas for natural gas engine generators needed to power equipment not otherwise connected to the power grid.
5. The Development Permit can document management and disposition for potential methane gas.

1.7 Term Permit Remains in Effect to Drill

1. Once approved, the Development Permit may contain a limit on the term it remains in effect for the operator to drill on the approved location.
    a. A limit on the term the permit remains in effect is intended to keep the conditions reported in the application current with respect to surrounding land uses and conditions.
2. In Colorado for example, under Rule 311.a, a permit to develop the approved location remains in effect for 3 years and expires if a well is not drilled within that time.
    a. Colorado does not approve extensions of the permit, according to Rule 311.b.
    b. New applications are subject to rules in effect at the time of submission, according to Rule 311.c.
3. Alternatively, Wyoming grants 2 years for drilling to commence under a permit to drill, according to Rule 055.0001.3, Section 8(h).
    a. Wyoming requires a new application 2 months prior to expiration and an extension fee to request a 2-year extension of the expiration date.

Colorado Energy & Carbon Management Commission, Rule 311
https://ecmc.state.co.us/documents/reg/Rules/LATEST/300%20Series%20-%20Permitting%20Process.pdf

Wyoming Oil & Gas Conservation Commission, Rule 055.0001.3
https://rules.wyo.gov/Search.aspx?mode=1

1.8 Term Permit Remains in Effect to Produce

1. The term that a permit remains in effect before expiring is common in environmental programs, such as 5 years for a National Pollutant Discharge Elimination System (NPDES) wastewater discharge permit.
2. In the oil and gas sector, multiple states reviewed for precedent on the term a permit remains in effect demonstrate no stated term. The states reviewed include Colorado, Kansas, Michigan, Montana, and Wyoming.
3. States may indicate that the permit remains valid *as long as the well is producing*. Under that circumstance, a permit can be revoked by states for the following reasons:
    a. Failure to comply with environmental standards
    b. Unsafe drilling practices
    c. Non-payment of fees or failure to submit required reports
    d. Failure to properly plug wells after they become non-productive
    e. Failure to meet requirements for well closure, plugging, and site reclamation

1.9 Reporting Requirements

1. The following can be considered for reporting in a Development Permit:
    a. Notice of Change
        1) Change to information submitted with the application, including disturbance area, well count, well drilling, planned equipment, disposal practices, and production operations
    a. Notice of Construction
        1) The permit may specify the number of days for notice to the agency in advance of mobilizing heavy equipment to construct a permitted location.
    b. Notice of Well Drilling
        1) The permit may specify the number of days for notice to the agency in advance of well drilling.
    c. Spill Notification
        1) In accordance with requirements in rules administered by PCA
    d. Operations Report
        1) Frequency and required information would be determined by the permitting agency, which could include monthly or semi-annual reporting for the volume of produced gas and any fluids.

2) The permitting agency can require metering equipment identified through industry standards established by the American Petroleum Institute (API), with required annual calibration.

3) Should they be determined necessary for a Development Permit, Colorado provides examples at Rule 405 of additional operations requiring individual notice.

e. Notice of Shut-in, Temporarily Abandoned, Abandoned Well

1) A well may be shut in after drilling and testing for a period that provides for installation of production equipment.

2) A well may be temporarily abandoned for a period that provides for future use, such as completion or deepening.

3) A well may be plugged and abandoned if testing does not demonstrate economical volumes of helium gas.

f. In Utah at Rule 649-3-39.3.3.4 (in the context of hydraulic fracturing), operators must also file an Annual Waste Management Plan to report the proper disposition of produced water and other exploration and production (E&P) waste.

Colorado Energy & Carbon Management Commission, Rule 405
https://ecmc.state.co.us/documents/reg/Rules/LATEST/400%20Series%20-%20Operations%20and%20Reporting.pdf

Utah Division of Oil, Gas and Mining, Rule 649-3
https://adminrules.utah.gov/public/rule/R649-3/Current%20Rules?searchText=R649

Siting

1.10 Siting Restrictions

1. Disturbance for an oil and gas operation is generally prohibited in habitats for species designated endangered, threatened, or special status.

   a. Exceptions may be granted for access roads and flowlines in the buffer areas for certain aquatic habitats, as they are in Colorado under Rule 1202.c.(2).C.

2. Protection for avian species can include a requirement to conduct vegetation removal outside of the nesting season for migratory birds or, alternatively, to conduct a pre-construction survey for nesting migratory birds. An example is at Colorado Rule 1202.a.(8).

Colorado Energy & Carbon Management Commission, Rule 1202
https://ecmc.state.co.us/documents/reg/Rules/LATEST/1200%20Series%20-%20Protection%20of%20Wildlife%20Resources.pdf

1.11 Setbacks

1. Setbacks from a residential building vary by state with examples of the required distance listed below.

   a. Residential can include schools, childcare centers, offices, and hospitals, according to individual state requirements.

   b. Residential generally does not include garages, barns, and outbuildings.

   c. States vary in measuring from the well or measuring from the edge of the well pad.

Residential Setbacks	
State	**Setback (feet)**
Colorado	2,000
Montana	1,320
North Dakota	500
Wyoming	500
Utah	460
Michigan	300
Pennsylvania	200

2. Setbacks from roadways are identified by certain states. Examples are listed below.
    a. The measurement and application of the setback affects its restrictiveness. These vary from the edge of the road to the edge of the traveled portion of an interstate or state highway, to the centerline of an interstate or state highway.

Roadway Setbacks	
State	**Setback (feet)**
Michigan	300
Colorado	200
North Dakota	200

    b. In addition to roadways, setbacks are applied in certain states to aboveground utilities and railroads.

3. Setbacks from water wells are identified by certain states. Examples are listed below.

Water Well Setbacks	
State	**Setback (feet)**
Colorado	2,640
Kansas	660
Michigan	300
Pennsylvania	200

4. A process generally exists to grant a waiver or variance after site-specific evaluation by the regulatory agency or a consulting agency.
    a. Proximity to a residence may consider, for example, the consent of the affected property owner.
    b. Habitat review may consider habitat type, suitability, use as habitat, and existing integrity.
    c. Surface water review may consider site survey for mapped waters and wetlands, erosion potential, spill controls, topography, and floodplains.
5. Measures to avoid, minimize, or mitigate impacts can be incorporated into a permit as Conditions of Approval or Best Management Practices.

Colorado Energy & Carbon Management Commission, Rule 304.b.(2).B
https://ecmc.state.co.us/documents/reg/Rules/LATEST/300%20Series%20-%20Permitting%20Process.pdf

Colorado Energy & Carbon Management Commission, Rule 604
https://ecmc.state.co.us/documents/reg/Rules/LATEST/600%20Series%20-%20Safety%20and%20Facility%20Operations%20Regulations.pdf

*Colorado Energy & Carbon Management Commission, Rule 1202.*a
https://ecmc.state.co.us/documents/reg/Rules/LATEST/1200%20Series%20-%20Protection%20of%20Wildlife%20Resources.pdf

Kansas Corporation Commission, Rule 82-3-108.(a)
https://www.kcc.ks.gov/images/PDFs/oil-gas/conservation/cons_rr_091615.pdf

Michigan Department of Environmental Quality, Rule 324.201.2.b.iv.A, Rule 324.504
https://dtmb.state.mi.us/ORRDocs/AdminCode/1889_2019-001EQ_AdminCode.pdf#:~:text=These%20rules%20govern%20oil%20and%20gas

Montana Board of Oil and Gas Conservation, Rule 36.25
https://casetext.com/regulation/montana-administrative-code/department-36-natural-resources-and-conservation/chapter-3625-state-land-leasing/subchapter-36252-rules-governing-the-issuance-of-oil-and-gas-leases-on-state-lands/rule-3625223-minimum-restrictions-on-surface-activity

North Dakota Department of Mineral Resources, Rule 38-08-05.2
https://ndlegis.gov/cencode/t38c08.pdf, https://www.dmr.nd.gov/oilgas/DMR-drill-101_106.pdf

Pennsylvania Code, Section 3215.0 Title 58
https://www.legis.state.pa.us/WU01/LI/LI/CT/HTM/58/00.032.015.000..HTM#:~:text=%281%29%20No%20well%20site%20may%20be%20prepared%20or,quadrangle%20map%20of%20the%20United%20States%20Geological%20Survey.

Wyoming Oil and Gas Conservation Commission Rule 055.0001.3, Section 47.(a)
https://rules.wyo.gov/Search.aspx#

1.12 Surface Use Agreement

1. The requirements listed below can be considered for inclusion in a Surface Use Agreement (SUA) between the operator and the surface owner.
    a. If an operator is not relying on a lease for its right to construct, the requirements can be included in the Development Permit.
2. Requirements:
    a. Clearly provide a "Right to Construct."
    b. Include a legal description of the lands subject to the agreement.
    c. Clearly state that it applies to gas or helium operations.
    d. Include signatures for the operator and surface owner.
    e. Include language on successors and assigns if a successor operator is using the SUA for siting.

Leasing

1.13 Examples for State Mineral Leases

1. The recommended practice for helium is for the state to lease helium consistent with a state leasing process for oil and natural gas. This approach is used in Colorado and Wyoming.

See Section 4.e., Definition of "Gas", in Colorado Oil and Gas Lease Sample, https://drive.google.com/file/d/1w2BvfCyTxPvEXHa9veZm9j6NYFeDnl80/view

2. For comparison, Utah uses a non-solicited "Other Business Arrangement" (OBA) (*see* No. 11 below) or other non-lease process.
3. Colorado and Wyoming appear to use a 16.67 percent royalty rate in their respective oil and gas leases.
4. A 16.67 percent royalty rate is consistent with the Bureau of Land Management (BLM) royalty rate for leases issued between 2022 and 2032 at 43 C.F.R. § 3103.31(a)(2).
5. Colorado oil and gas lease samples are viewable here:

   https://drive.google.com/file/d/1w2BvfCyTxPvEXHa9veZm9j6NYFeDnl80/view

   https://ecmc.state.co.us/weblink/DownloadDocumentPDF.aspx?DocumentId=3097274
6. A Wyoming oil and gas lease form is viewable here:

   https://drive.google.com/file/d/1wNbWGPaaASDVzQt-zYVdegAKDP6eZ_xA/view
7. A BLM oil and gas lease (Form 3100-11) is viewable here:

   https://www.blm.gov/sites/blm.gov/files/uploads/Services_National-Operations-Center_Eforms_Fluid-and-Solid-Minerals_3100-011.pdf
8. A BLM Competitive Oil and Gas or Geothermal Resources Lease Bid (Form 3000-002) is viewable here:

   https://www.blm.gov/sites/default/files/docs/2024-05/3000-002.pdf
9. Colorado Lease Process:
   a. Colorado's State Land Board offers oil and gas leases through competitive auctions.
   b. Auctions occur online.
   c. Anyone can nominate state minerals for auction to obtain a lease.
   d. Leases are awarded to the highest bidder on a per acre basis.
   e. The minimum bid amount per acre is the annual lease rental rate.

   Colorado State Land Board Oil & Gas Auction and Results https://slb.colorado.gov/public-notices/auction-results
10. Wyoming Lease Process:
    a. Oil and gas leases can be acquired through two methods.
       1) First, parcels that are available for lease are auctioned through a competitive bid process. If a parcel is not successfully bid upon, the parcel may be offered at a second auction.
       2) Second, if a parcel is not successfully bid upon a second time, the parcel may become available "over the counter" at set prices.

    Wyoming Oil & Gas Leases: https://lands.wyo.gov/trust-land-management/mineral-leasing/oil-gas-leases

11. Utah Lease Process:
    a. Utah follows a different process than Colorado and Wyoming.
    b. In Utah, helium is “leased” via OBA.
    c. OBA’s are customized agreements with Utah’s School and Institutional Trust Lands Administration (SITLA), which requires the project proponent to use geographic information system (GIS) maps to ensure that the interested lands are not already subject to an existing lease.
    d. The project proponent must reach out to the SITLA Energy & Minerals group to submit a letter of interest explaining the nature of the transaction (e.g., royalty rate, plan of development, etc.).
    e. The Energy & Minerals group lease managers then reach out to begin negotiation.
    f. The OBA is approved by the SITLA Board of Trustees.

    Utah SITLA Other Business Arrangements: https://trustlands.utah.gov/work-with-us/energy-minerals/oba/

Spacing / Unitization

1.14 Technically Supported Drilling Spacing Unit

1. The area of development for a Drilling Spacing Unit (DSU) can be supported using engineering testimony demonstrating one or more of the following:
    a. Fluid reservoir properties including, as appropriate, fluid types, API gravity, specific gravity, gas/oil ratio, formation volume factor, porosity, pore space saturation and permeability
    b. Evaluation of analog wells in the nearby area, if available
    c. Table of reservoir engineering calculations for original gas-in-place, estimated ultimate recovery (EUR), and the calculated drainage area for each well
    d. Decline curve(s) and how the analysis was used to calculate EURs for use in the drainage area calculations
    e. Reservoir data, including pressure surveys, material balance calculations, and other reservoir information that supports the size and continuity of the reservoir, or the productivity of the reservoir(s)
    f. Seismic survey maps, if available, interpreting section lines and synthetic seismic logs
    g. Microseismic data, if available, with an indication of the confidence interval, signal to noise ratio, and/or magnitude of microseismic events
2. The presence of the formation within the defined DSU can be supported using geology testimony demonstrating one or more of the following:
    a. Summary of the formation(s) to be spaced including the name, description, lithology, characteristics, depositional origin and, if applicable, faults, folds, stratigraphy variation, and trap type
    b. Description of the thickness, lateral extent, and depth of the formation(s) to be spaced
    c. Structure contour map showing the top subsea elevation of the formation(s) to be spaced
    d. Isopach map showing gross or net thickness of the formation(s) to be spaced

e. Cross-section showing the geology of the formation(s) to be spaced

f. Type log showing the geology of the formation(s) to be spaced

1.15 Protect Correlative Rights / Prevent Waste

1. Correlative rights can be defined in statute.

   a. In Colorado, Colorado Revised Statute (C.R.S.) § 34-60-103(6)(a) defines correlative rights as "each owner and producer in a common pool or source of supply of oil and gas must have an equal opportunity to obtain and produce the owner's or producer's just and equitable share of the oil and gas underlying the pool or source of supply."

   b. Colorado statute at C.R.S. § 34-60-117 prohibits harm to correlative rights.

   c. Colorado statute and ECMC rules require ECMC to protect correlative rights.

   d. The evaluation of new spacing in Minnesota can similarly include the requirement to protect correlative rights.

2. Preventing waste can be defined in statute.

   a. In Colorado, C.R.S. 34-60-103(43), (44) and (45) define waste as it applies to oil, gas, and generally, including:

      1) Physical waste, as that term is generally understood in the oil and gas industry;

      2) The locating, spacing, drilling, equipping, operating, or producing of any oil or gas well or wells in a manner that causes or tends to cause reduction in quantity of oil or gas ultimately recoverable from a pool under prudent and proper operations or that causes or tends to cause unnecessary or excessive surface loss or destruction of oil or gas;

      3) Abuse of the correlative rights of any owner in a pool due to nonuniform, disproportionate, unratable, or excessive withdrawals of oil or gas from the pool, causing reasonably avoidable drainage between tracts of land or resulting in one or more producers or owners in the pool producing more than an equitable share of the oil or gas from the pool; and

      4) Does not include the nonproduction of oil or gas from a formation if necessary to protect public health, safety, and welfare; the environment; or wildlife resources.

   b. In Colorado, ECMC also has a duty at C.R.S. § 34-60-117 to prevent waste.

   c. The evaluation of new spacing in Minnesota can similarly include the requirement to prevent waste.

Colorado Revised Statute, Title 34, Article 60, Energy and Carbon Management
https://advance.lexis.com/container?config=0345494EJAA5ZjE0MDIyYy1kNzZkLTRkNzktYTkxMS04YmJhNjBlNWUwYzYKAFBvZENhdGFsb2e4CaPI4cak6laXLCWyLBO9&crid=5d45e50e-a97a-4d50-8564-5829d9c816b0&prid=e49f6bad-fe66-499f-9d93-5b4d2f62d7fa

1.16 Threshold Leasehold Ownership to Obtain a DSU

1. An operator seeking to establish a DSU for a proposed development area should own or have the consent to operate within the proposed unit.

   a. In Colorado, "Owner" means "the person who has the right to drill into and produce from a pool and to appropriate the oil or gas produced therefrom either for such owner or others or for such owner and others, including owners of a well capable of producing oil or gas, or both."

2. Evidence of mineral ownership or consent to develop would be included as a requirement in the spacing application.
3. In Colorado, an operator cannot pool interests within an established DSU without first owning and/or obtaining the consent of the owners of more than 45 percent of the mineral interests to be pooled.
4. While Colorado does not require 45.1 percent ownership or consent at the time of spacing, the ECMC considers this threshold as it relates to future pooling.
5. Colorado recently enacted a new law at C.R.S. § 34-60-116 that requires a pooling applicant to submit to the ECMC an affidavit with a lease schedule, including recording information and wells holding each lease by production, to demonstrate that the operator owns at least 45.1 percent of the leasehold interests to be pooled.
6. Wyoming has no pooling ownership threshold. In Wyoming, the operator has the right to drill and develop within the defined lands.

   Colorado Energy & Carbon Management Commission, Rule 100
   https://ecmc.state.co.us/documents/reg/Rules/LATEST/100%20Series%20-%20Definitions.pdf

   Colorado Revised Statute, Title 34, Article 60, Energy and Carbon Management
   https://advance.lexis.com/container?config=0345494EJAA5ZjE0MDIyYy1kNzZkLTRkNzktYTkxMS04YmJhNjBlNWUwYzYKAFBvZENhdGFsb2e4CaPI4cak6laXLCWyLBO9&crid=5d45e50e-a97a-4d50-8564-5829d9c816b0&prid=e49f6bad-fe66-499f-9d93-5b4d2f62d7fa

Pooling

1.17 General

1. Most states with oil and gas reserves have enacted statutory pooling laws to encourage development of the resource and participation by mineral owners.
2. In Colorado and Wyoming, pooling may be done voluntarily between parties.
   a. Voluntary pooling may be done through contracts, in which state entities will have little to no involvement.
3. Involuntary pooling may be done by an operator if the operator fulfills certain statutory requirements.
4. In Colorado, a pooling order does not expire.
5. In Wyoming Statute at 30-5-109.(f), a pooling order will expire (become non-effective) 12 months after the Oil & Gas Conservation Commission approves the order if the well is not drilled within the 12 months following order approval.

   Wyoming Statute, Title 30, Chapter 5, Oil and Gas
   https://wyoleg.gov/statutes/compress/title30.pdf

1.18 Identification of Mineral Owners

1. An operator can apply for pooling with the spacing of a DSU or after the DSU has been established.
   a. The DSU should at least be established before minerals are pooled within the unit.

2. Prior to applying for pooling, an operator should identify the unleased mineral owners; leasehold (working interest) owners; and leased royalty owners within the unit.
3. Also prior to applying for pooling, requirements for tendering lease offers and elections to participate can be imposed.

Colorado Energy & Carbon Management Commission, Rule 506
https://ecmc.state.co.us/documents/reg/Rules/LATEST/500%20Series%20-%20Rules%20of%20Practice%20and%20Procedure.pdf

1.19 Notification of Mineral Owners

1. Notification to unleased mineral owners, leasehold (working interest) owners, and leased royalty owners would occur when an operator applies for pooling.
2. Recent revision to the statute in Colorado regarding pooling at C.R.S. § 34-60-116 requires a 60-day protest/petition period by unleased mineral owners prior to a hearing on a pooling application.

   Colorado Revised Statute, Title 34, Article 60, Energy and Carbon Management
   https://advance.lexis.com/container?config=0345494EJAA5ZjE0MDIyYy1kNzZkLTRkNzktYTkxMS04YmJhNjBlNWUwYzYKAFBvZENhdGFsb2e4CaPI4cak6laXLCWyLBO9&crid=5d45e50e-a97a-4d50-8564-5829d9c816b0&prid=e49f6bad-fe66-499f-9d93-5b4d2f62d7fa

1.20 100 Percent Mineral Leasing Versus Statutory Pooling

1. Statutory (involuntary) pooling may not be required when 100 percent of the minerals within an established DSU are owned and/or leased to the operator.
2. No further state action is needed with respect to pooling when an operator is developing its 100 percent leasehold interests or if involuntary pooling is obtained.
3. At the time of filing for a Development Permit, the operator should state whether the minerals being developed are owned and/or leased 100 percent to the operator, or whether pooling is required.

1.21 Joint Operating Agreement

1. Participating mineral owners can execute a Joint Operating Agreement (JOA) with the operator, which provides the contractual basis for the cooperative exploration, development, and production of oil and gas properties among multiple leasehold cotenants.
2. The most commonly used JOA form is the “Form 610,” curated and published by the American Association of Professional Landmen.
3. Because the JOA is a contract between the operator and the participating leasehold owners, the state may be aware of the presence of a JOA but otherwise will not have regulatory authority over the JOA.

1.22 Nonconsent Working Interest / Unleased Mineral Owner

1. Statutory pooling may provide that the operator and consenting owners recover costs in the form of cost recovery penalties out of the nonconsenting owners’ share of production from a DSU.
2. After an operator (a) tenders (mails to a last known address) an election to participate in the proposed well(s), which is sent to the leasehold (working interest) and unleased owners within the unit, and (b) these mineral owners have a reasonable time to consider the election materials, then an operator may seek cost recovery penalties against a mineral owner that either 1) fails to respond to the election materials or 2) responds with an election not to participate.
   a. In Colorado, the reasonable time to consider the election materials is 60 days.

3. Colorado cost recovery penalties at C.R.S. § 34-60-116 are:
    a. 100 percent of the nonconsenting owners' share of the cost of surface equipment beyond the wellhead connections.
    b. 200 percent of that portion of the costs and expenses of staking, well site preparation, obtaining rights-of-way, rigging up, drilling, reworking, deepening or plugging back, testing, and completing the well, after deducting any cash contributions received by the consenting owners, and 200 percent of that portion of the cost of equipment in the well, including the wellhead connections.
4. Wyoming cost recovery penalties at Wyoming Statute 30-5-109 are:
    a. 100 percent of the nonconsenting owner's share of the cost of any newly acquired surface equipment (applies to all nonconsenting owners).
    b. 300 percent of that portion of costs and expenses drilling and reworking. 200 percent of that portion of costs of newly acquired equipment in the well, "if the nonconsenting owner's tract or interest is subject to a lease or other contract of oil and gas development" (applies only to nonconsenting owners who hold a lease).
    c. For the first well, 200 percent of that portion of costs and expenses of drilling and reworking. 125 percent of that portion of costs of newly acquired equipment in the well "if the nonconsenting owner's tract or interest is not subject to a lease or other contract for oil and gas development" (applies to unleased mineral owners).
    d. For each subsequent well, 150 percent of that portion of costs and expenses of drilling, reworking, etc. 125 percent of that portion of costs of newly acquired equipment in the well, "if the nonconsenting owner's tract or interest is not subject to a lease or other contract for oil and gas development" (applies to unleased mineral owners).

Colorado Revised Statute, Title 34, Article 60, Energy and Carbon Management
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Wyoming Statute, Title 30, Chapter 5, Oil and Gas
https://wyoleg.gov/statutes/compress/title30.pdf

1.23 Unleased Mineral Owner Royalty Cost Recovery

1. If an unleased owner refuses or does not respond to a lease offer, the unleased owner may be deemed to have a landowner's proportionate royalty.
2. After an operator tenders a reasonable lease offer to all unleased owners in the unit, and these unleased owners have a reasonable time to consider the lease offer, then an operator may seek cost recovery penalties in the form of statutory royalty against an unleased mineral owner that either 1) fails to respond to the lease offer or 2) responds with an explicit rejection of the lease offer.
    a. A reasonable lease offer is based on market rates.
    b. In Colorado, the reasonable time to consider the lease offer is 60 days.
3. Colorado statutory royalty at C.R.S. § 34-60-116 is:
    a. For a gas well, 13 percent until the consenting owners recover, only out of the nonconsenting owner's proportionate 87 percent share of production, the costs specified in the statute; or

b. For an oil well, 16 percent until the consenting owners recover, only out of the nonconsenting owner's proportionate 84 percent share of production, the costs specified in the statute.

c. After recovery of the costs, the nonconsenting owner then owns his or her full proportionate share of the wells, surface facilities, and production and then is liable for further costs as if the nonconsenting owner had originally agreed to drilling of the wells.

4. Wyoming statutory royalty at Wyoming Statute 30-5-109 is:

d. 16 percent, or the acreage weighted average royalty interest of the leased tracts within the drilling unit.

Colorado Energy & Carbon Management Commission, Rule 506
https://ecmc.state.co.us/documents/reg/Rules/LATEST/500%20Series%20-%20Rules%20of%20Practice%20and%20Procedure.pdf

Colorado Revised Statute, Title 34, Article 60, Energy and Carbon Management
https://advance.lexis.com/container?config=0345494EJAA5ZjE0MDIyYy1kNzZkLTRkNzktYTkxMS04YmJhNjBlNWUwYzYKAFBvZENhdGFsb2e4CaPI4cak6laXLCWyLBO9&crid=5d45e50e-a97a-4d50-8564-5829d9c816b0&prid=e49f6bad-fe66-499f-9d93-5b4d2f62d7fa

Wyoming Statute, Title 30, Chapter 5, Oil and Gas
https://wyoleg.gov/statutes/compress/title30.pdf

1.24 Royalty Cost Recovery Reporting

1. Colorado requires that the operator of wells under a pooling order in which there is a nonconsenting owner furnish the nonconsenting owner with a monthly statement of all costs incurred, together with the quantity of oil or gas produced, and the amount of proceeds realized from the sale of production during the preceding month.

2. If the consenting owners recover the costs specified in statute, the nonconsenting owner will own the same interest in the wells, and the production therefrom, and will be liable for the further costs of the operation, as if the owner had participated in the initial drilling operations.

Colorado Energy & Carbon Management Commission, Rule 506
https://ecmc.state.co.us/documents/reg/Rules/LATEST/500%20Series%20-%20Rules%20of%20Practice%20and%20Procedure.pdf

Colorado Revised Statute, Title 34, Article 60, Energy and Carbon Management
https://advance.lexis.com/container?config=0345494EJAA5ZjE0MDIyYy1kNzZkLTRkNzktYTkxMS04YmJhNjBlNWUwYzYKAFBvZENhdGFsb2e4CaPI4cak6laXLCWyLBO9&crid=5d45e50e-a97a-4d50-8564-5829d9c816b0&prid=e49f6bad-fe66-499f-9d93-5b4d2f62d7fa

Reclamation

1.25 Interim Reclamation

1. Interim reclamation refers to reducing the well pad after drilling is complete to the size needed to support production. The remaining area would be required to be reclaimed by restoring and revegetating the disturbed surface.

2. States vary from specific reclamation requirements in Colorado at Rule 1003 for debris removal, soil salvage, vegetative cover, and weed control to a general requirement in Kansas at Rule 55-182 to restore the area to original contour and condition as nearly as practicable. Likewise, Montana at Rule 36.22.1307 has only a general requirement to restore the surface to its previous grade and productive capability.

3. A timeframe can be specified to conduct interim reclamation.
    a. In Colorado at Rule 1003.b, the timeframe is 3 months after well drilling is complete for cropland and 6 months for non-cropland.
4. Additional practices below can be specified to facilitate successful reclamation and revegetation.
    a. Disturbance for the well pad would be limited to the area necessary to place and level equipment for well drilling and production.
    b. Equipment not needed to support production would be removed after well drilling.
    c. Debris and trash would be removed from the site.
    d. Topsoil stripped during construction of the well pad would be stockpiled and replaced during reclamation.
    e. The topsoil stockpile would be protected from parking and contamination during well drilling and production.
    f. The topsoil stockpile would be protected from stormwater erosion and runoff through stormwater controls and vegetative cover.
    g. Reclaimed areas would be seeded with a certified weed-free seed mix that is consistent with native vegetation.
    h. The operator would continue to manage the location for stormwater runoff and weeds until the area is stabilized according to provisions in its construction stormwater permit.

Colorado Energy & Carbon Management Commission, Rule 1003
https://ecmc.state.co.us/documents/reg/Rules/LATEST/1000%20Series%20-%20Reclamation%20Regulations.pdf

Kansas Corporation Commission, Rule 55-182
https://www.kcc.ks.gov/images/PDFs/oil-gas/conservation/cons_rr_091615.pdf

Montana Board of Oil and Gas Conservation, Rule 36.22.1307
https://rules.mt.gov/browse/collections/aec52c46-128e-4279-9068-8af5d5432d74/policies/6c4248a4-a1b8-48aa-99f4-68bb1d024081

1.26 Final Reclamation

1. Final reclamation refers to restoration of the site after the well is plugged and abandoned and the site no longer supports production. The surface, including the access road, would be returned to a pre-existing condition.
    a. In some cases, the landowner may specify in its agreement with the operator that an access road remain in place for the landowner’s own use.
2. Final reclamation requirements are designed to return the surface to a stable and productive condition for future use without environmental risks.
3. States vary from specific reclamation requirements in Colorado at Rule 1004 for final closure, recontouring and revegetation, inspection, and bond release to more general requirements in Wyoming at Rule 055.0001.4.rr for site rehabilitation in accordance with reasonable landowner wishes and/or to resemble the original vegetation and contour of adjoining lands.
4. A timeframe can be specified to conduct final reclamation.

   a. In Colorado at Rule 1004.a, the timeframe is 3 months after well plugging or site closure for cropland and 12 months for non-cropland.
   b. In North Dakota at Rule 43-02-03-34.1, the timeframe is 12 months after well plugging or site decommissioning.
5. Additional practices below can be specified to facilitate final closure.
   a. Submitting a Reclamation Plan is required in certain states, such as Colorado and North Dakota.
   b. Risers, flowlines at the location, culverts, equipment, debris, trash, and surfacing material (e.g., gravel) would be removed.
   c. The site and access road would be de-compacted, recontoured, and graded.
   d. Stormwater control materials would be removed.
   e. Hydrological flow patterns for stormwater would be restored.
   f. Topsoil preserved for final reclamation would be restored.
   g. Reclaimed areas would be seeded with a certified weed-free seed mix that is consistent with native vegetation.
   h. The operator would continue to monitor the site and reseed, as necessary, until revegetation stabilizes exposed soils.
   i. Bonding would be held until final reclamation is inspected and found complete.

Colorado Energy & Carbon Management Commission, Rule 1004
https://ecmc.state.co.us/documents/reg/Rules/LATEST/1000%20Series%20-%20Reclamation%20Regulations.pdf

North Dakota Department of Mineral Resources Rule 42-02-03-34.1
https://ndlegis.gov/information/acdata/pdf/43-02-03.pdf

Wyoming Oil & Gas Conservation Commission, Rule 055.0001.4, Section 1.(rr)
https://rules.wyo.gov/Search.aspx?mode=1

Site Closure

1.27 Site Closure Requirements

1. Site closure refers to abandonment of the location not otherwise addressed by well plugging.
2. Equipment, infrastructure, trash, and debris would be removed from the site.
3. Waste from drilling and production would require proper final disposal in an approved landfill, disposal facility, or as otherwise indicated in the operator’s permit.
4. Associated flowlines would be purged and permanently sealed or removed.
5. In Colorado at Rule 603.m, the operator must initiate closure of the well site within 90 days after a well is plugged and abandoned.
   a. In North Dakota, the timeframe increases to 1 year.
   b. North Dakota requires that any flowline buried less than 3 feet below the final surface be removed rather than abandoned in place.

Colorado Energy & Carbon Management Commission, Rule 603

https://ecmc.state.co.us/documents/reg/Rules/LATEST/600%20Series%20-%20Safety%20and%20Facility%20Operations%20Regulations.pdf

North Dakota Department of Mineral Resources, Rule 43-02-03-34.1
https://ndlegis.gov/information/acdata/pdf/43-02-03.pdf

Financial Assurance

1.28 Application Fee

1. Example fees by state are listed below.

Application Fee	
Illinois	$400
Kansas	$300
Michigan	$300
Montana	$25 - $75
North Dakota	$100
Wyoming	$500
U.S. Bureau of Land Management	$12,515[1]

[1]Onshore O&G Operations and Production, Application for Permit to Drill

Illinois Department of Natural Resources
https://dnr.illinois.gov/oilandgas/formslistslogs.html

Kansas Corporation Commission, Rule 55-151.b
https://www.kcc.ks.gov/images/PDFs/oil-gas/conservation/cons_rr_091615.pdf

Montana Board of Oil and Gas Conservation, Rule 36.22.603
https://casetext.com/regulation/montana-administrative-code/department-36-natural-resources-and-conservation/chapter-3622-oil-and-gas-conservation/subchapter-36226-permit-to-drill/rule-3622603-permit-fees?searchWithin=true&listingIndexId=montana-administrative-code.department-36-natural-resources-and-conservation.chapter-3622-oil-and-gas-conservation.subchapter-36226-permit-to-drill&q=water%20well&type=regulation&sort=relevance&p=1

North Dakota Department of Environmental Quality, Rule 43-02-03-16
https://ndlegis.gov/information/acdata/pdf/43-02-03.pdf
https://deq.nd.gov/AQ/oilgas/OilGasRegistration.aspx

Wyoming Oil and Gas Conservation Commission, Rule 055.0001.3, Section 8
https://rules.wyo.gov/Search.aspx

U.S. Bureau of Land Management Fixed Filing Fees
https://www.blm.gov/fixed-filing-fee-schedule-blm-energy-and-minerals

1.29 Application Review Fee

1. Examples of agencies that charge an hourly fee for oil and gas-related application review for permits in their jurisdiction are listed below.

Application Review Fee	
Garfield County, Colorado	Staff or Consultant Hourly Rate
Wyoming Department of Environmental Quality	Staff Hourly Rate
U.S. Bureau of Land Management	Escalating Rate by Category and Hours

Application Review Fee	
U.S. Forest Service	Escalating Rate by Complexity and Hours

2. The federal agencies listed above are granted authority to charge fees for processing applications related to land use and minerals.
3. Agencies bill the applicant for the time necessary to review and process the application.
4. A mechanism is in place to adjust fees annually for inflation.

Garfield County, Colorado Planning Review Process Fee Schedule
https://www.garfield-county.com/community-development/filesgcco/sites/12/2019/01/Fee-Schedule.pdf

U.S. Bureau of Land Management Cost Recovery Process and Monitoring Fee Schedule
https://www.blm.gov/sites/default/files/docs/2023-12/IM2024-008%20att1.pdf

U.S. Forest Service Code of Federal Regulations Title 36, Chapter II, Section 251.58
https://www.ecfr.gov/current/title-36/chapter-II/part-251/subpart-B/section-251.58

Wyoming Department of Environmental Quality Oil and Gas Production Facilities Chapter 6, Section 2
https://drive.google.com/file/d/1IbN-U0sDMDsYjhaPwwf1GnFX1avKsIdv/view

1.30 Annual Fee

1. Publicly available annual fees appear limited to fees in the range of $100 per operator and either a fee per well (e.g., $25/well) or escalating fee by volume of wells (e.g., $150 to $750+ per category).
2. There were no fees identified that would be comparable in scale to the annual fees imposed for mining operations in Minnesota Statute 93.482.

1.31 Plugging, Reclamation, Surface Bonding

1. In Colorado, financial assurance is required for all operators of drilled wells and unexpired permits.
    a. Operators must have financial assurance with the ECMC, even when the operator also has financial assurance with a federal agency, such as the BLM.
    b. Bonding is treated differently at ECMC Rule 703 for wells than it is for the following categories of operations: centralized exploration and production waste facilities, remediation projects, seismic operations, gas gathering, gas processing, underground gas storage facilities, produced water transfer systems, and commercial disposal facilities.
2. Financial assurance may be a surety bond, cash bond, letter of credit, sinking fund, third-party trust fund, escrow account, lien on property, security interest, or other instrument or method accepted by ECMC to ensure an operator is able to perform its obligations under the Colorado Oil and Gas Act and ECMC rules.
3. Financial assurance requirements for oil and gas operators are generally more detailed in Colorado than in other oil and gas states and are summarized below.
    a. Colorado operators of one or more producing or actively permitted wells must have an approved Financial Assurance Plan filed with the ECMC.
    b. Colorado operators must have bonding based primarily on production volumes.

c. Options 1, 2, 3 and 6 Financial Assurance Plans require the calculation of average daily production per well in thousand cubic feet of gas equivalent (MCFE).

d. At Colorado Rules 702.c and 702.d, bonding ranges from single well financial assurance, to per well calculations based on classification for the number of wells operated, to a $40,000,000 blanket bond for public companies with high production rates.

e. At Colorado Rule 100, single well financial assurance is defined using an estimate of $100,000 to reclaim the surface location and $10,000 to plug a well that is 4,000 feet deep, or less, and $30,000 to plug a well that is more than 4,000 feet deep and equal to or less than 8,000 feet deep.

f. Options 4 and 5 Financial Assurance Plans are for operators reporting zero production or for individual circumstances that require ECMC Commissioners to approve alternative bonding amounts.

4. Each Financial Assurance Plan in Colorado must contain an Asset Retirement Plan.

5. In Colorado at Rule 704, if a surface owner is not a party to a lease, surface use agreement, or other relevant agreement with an operator, the operator must provide financial assurance to the ECMC before commencing operations with heavy equipment on that surface owner's property.

6. Colorado at Rule 705 requires general liability insurance in the minimum amount of $5,000,000 per occurrence.

7. Colorado at Rule 706 will not release financial assurance until the well is properly plugged and abandoned and the location is fully reclaimed.

8. For comparison, in Wyoming bonding is based on the number of wells, well depth, and the type of minerals involved.

   a. Fee minerals in Wyoming are bonded with the Wyoming Oil & Gas Commission.

   b. State minerals are bonded with the Office of Public Lands and Investments.

   c. Federal minerals are bonded with the BLM in the county where the well is located.

9. Oil and gas bonding requirements in Wyoming include the following:

   a. Individual well bonds are $10 per foot of the well bore and are adjusted every 3 years.

   b. Blanket bonds are $100,000 for multiple wells, regardless of well depth.

   c. Idle wells may be subject to an increase in the bond amount of up to $10 per foot of the well bore.

Colorado Energy & Carbon Management Commission 100-Series Definitions
https://ecmc.state.co.us/documents/reg/Rules/LATEST/100%20Series%20-%20Definitions.pdf

Colorado Energy & Carbon Management Commission 700-Series Rules
https://ecmc.state.co.us/documents/reg/Rules/LATEST/700%20Series%20-20Financial%20Assurance.pdf.

Wyoming Oil and Gas Conservation Commission, Chapter 3, Section 4 Bonding Requirements
https://rules.wyo.gov/Search.aspx?mode=7

Glossary of Terms

1.32 Oil & Gas Sector Terminology

Terms commonly used in the oil and gas sector are shown in the table below. Some of the terms contrast with terms applied to mining operations or water wells in Minnesota.

Terms	
Terms in Current Use in Minnesota	**Oil and Gas Sector**
Project	Operation
Explorer	Operator
Well contractor	Driller
Drill site	Well pad
Exploratory boring	Exploration well
Extraction	Production
Sealing	Plugging
Grouting	Cementing
Aboveground storage tank	Produced water tank
Driveway	Access road
Industrial waste	Exploration & Production (E&P) waste
Piping	Flowline or pipeline

2.0 Minnesota Department of Revenue

Taxation

2.1 Precedent for Helium-specific Tax Rate

1. Severance taxes are taxes set and collected at the state level for extraction of natural resources, such as oil and natural gas.
2. Severance taxes for oil and gas are typically calculated based on the value and/or volume produced.
3. Best practice for a severance tax applicable to helium is to ensure that the statute or regulations implementing the severance tax are clear on its application to helium gas and to provide clear direction on calculation of the proceeds subject to the severance tax.
4. Colorado example:
   a. Colorado has a severance tax on (1) metallic minerals (2) molybdenum (ore) (3) oil and gas (4) oil shale and (5) coal. *See* C.R.S. § 39-29-103 through 107.
   b. Colorado does not have a severance tax specific to helium. Instead, "gas" means natural gas, coalbed methane, and CO2. *See* C.R.S. § 39-29-102(2.5).
   c. For each taxable year, a tax on the gross income attributable to the sale of crude oil, natural gas, CO2, and oil and gas is collected at the following rates [*See* C.R.S. § 39-29-105(1)(a)]:

Gross Income	Severance Tax
Under $25,000	2%
$25,000 and under $100,000	3%
$100,000 and under $300,000	4%
$300,000 and over	5%

   d. "Gross Income" is calculated by deducting from gross lease revenues any costs borne by the taxpayer for transporting, manufacturing, and processing identifiable, measurable oil or gas. *See* 1 CCR 201-10 and C.R.S. § 39-29-102(3)(a).
5. New Mexico example:
   a. New Mexico has a severance tax on oil, natural gas, liquid hydrocarbons, CO2, helium, and non-hydrocarbon gases. *See* New Mexico Stat. Ann. § 7-29-4(A).
   b. For CO2, helium, and non-hydrocarbon gases, the severance tax is 3.75 percent of the taxable value.
   c. To determine the taxable value of helium, the following is deducted from the value of products: (1) royalties paid or due the United States or the state of New Mexico (2) royalties paid or due any Indian tribe, Indian pueblo or Indian that is a ward of the U.S. and (3) the reasonable expense of trucking any product from the production unit to the first place of market. *See* New Mexico Stat. Ann. § 7-29-4.1.

6. Wyoming example:

   a. Wyoming has a severance tax on coal, oil and gas, bentonite, uranium, sand and gravel, and other valuable deposits. *See* 39 Wyo. Stat. Ann. § 39-14-101 through 701.

   b. Helium is subject to the severance tax rate for natural gas, which is 6 percent on the value of gross product of helium. *See* 39 Wyo. Stat. Ann. § 39-14-204(a), 212(f), 203(a)(i).

   c. The "value of the gross product" means fair market value, less any deductions and exemption allowed by Wyoming law or rules. *See* 39 Wyo. Stat. Ann. § 39-14-201(a)(xxix).

   d. The fair market value of natural gas is determined after the production process is completed. *See* 39 Wyo. Stat. Ann. § 39-14-203(b)(ii).

   e. Helium from a natural gas stream leased by the U.S. to any lessee pursuant to the Mineral Leasing Act of 1920 is exempt from this severance tax. *See* 39 Wyo. Stat. Ann. § 39-14-212(g).

Colorado Code of Regulations, 1 CCR 201-10, Severance Tax
https://www.sos.state.co.us/CCR/KeywordSearch.do?id=&submit=Search&keyword=201&d-49216-p=2&endDate=&startDate=

Colorado Revised Statute, Title 39, Article 29, Severance Tax
https://advance.lexis.com/container?config=0345494EJAA5ZjE0MDIyYy1kNzZkLTRkNzktYTkxMS04YmJhNjBlNWUwYzYKAFBvZENhdGFsb2e4CaPI4cak6laXLCWyLBO9&crid=fc0ae068-f0d2-48ce-a877-f8f48c94a079&prid=5d45e50e-a97a-4d50-8564-5829d9c816b0

New Mexico Statutes Annotated, Article 29, Title 7, Oil and Gas Severance Tax
https://nmonesource.com/nmos/nmsa/en/item/4340/index.do#!fragment/zoupio-_Toc170909147/BQCwhgziBcwMYgK4DsDWszIQewE4BUBTADwBdoAvbRABwEtsBaAfX2zgEYB2ABgE5+HACxcAIABpk2UoQgBFRIVwBPaAHI14iITC4ECpao1adekAGU8pAEKqASgFEAMg4BqAQQByAYQfjSYABG0KTsoqJAA

Wyoming Statute, Title 39, Chapter 14, Taxation and Revenue
https://wyoleg.gov/statutes/compress/title39.pdf

2.2 Helium Gas Versus Liquid Helium Pricing

1. Helium pricing increases as raw gas is separated to produce crude helium gas (e.g., >90% to 98% crude helium) and then purified further as liquid helium (e.g., 99.997% Grade A market premium helium).

2. In its purified state, liquid helium may be converted back to gaseous form depending on the end user's requirements, such as use in semiconductor manufacturing.

3. The initial raw gas may contain helium together with hydrocarbons, CO_2, nitrogen, and other constituents.

4. When raw gas is separated, helium can be concentrated, compressed, loaded into transportation cylinders ("tubes"), and trucked in gaseous form directly from processing equipment on a well pad to market. Or helium can be processed at another location off of the well pad containing the same helium recovery equipment and then trucked from there to market.

5. Alternatively, either the raw gas or crude helium can be processed at a facility (liquefaction plant) designed to purify and liquify helium to Grade A. Helium liquifies by cooling to approximately minus 269^{o}C (cryogenic).

6. The pricing premium on liquid helium is a reflection of its purity and the market demand for purity, rather than a reflection of the cost of converting gas to liquid. Demand for purity is demonstrated

by a buyer that may purchase market premium liquid helium only to re-gasify it according to user needs in manufacturing, research, medical, aerospace, and other sectors.

2.3 Publicly Available Helium Pricing

1. Gas is measured as a volume in cubic feet (CF). The volume at the well is typically measured in thousands using the Roman numeral "M", where 1,000 cubic feet of gas is 1 MCF and 1,000 cubic feet of gas per day is 1 MCFD.
2. Helium does not have published commodity pricing. Pricing is determined by private transactions through contracts.
3. Companies and analysts report highly variable prices, such as post-2022 pricing from $250 MCF to $800 MCF, or more, depending on helium grade, price spikes from supply constraints, costs, transportation, and other factors.
4. States imposing a severance tax on production of helium may rely on information originating from operator revenue statements as the basis for computation of taxes.
   a. Revenue statements do not depend on publicly available commodity data.
   b. Revenue statements also cut across variable types of private helium transactions, from contracts, to auctions, to spot market sale.

2.4 Publicly Available Historical Helium Pricing

1. Unlike natural gas and oil, helium is not traded as a commodity on public markets that publish current pricing. Helium pricing is established through private transactions.
2. Operators may rely on industry knowledge, industry experts, and third-party consultants supporting helium contracts and transactions.
3. Publicly available information is available to identify recent *historical* helium production, pricing, and trends. A notable resource is the annual U.S. Geological Survey (USGS) *Mineral Commodity Summary*.
4. The table below summarizes the 10-year estimated prices per MCF for Grade A and crude helium sold from private industry to government users and from private industry to non-government users.

Year	Grade-A helium to government users (per MCF)	Crude helium to government users (per MCF)	Crude helium to non-government users (per MCF)
2023	$390	Not available	Not available
2022	$310	Not available	Not available
2021	$210	$100	$100
2020	$210	$86	$119
2019	$210	$86	$119
2018	$210	$86	$119
2017	$200	$83	$107
2016	$200	$84.40	$104
2015	$200	$85	$104
2014	$200	$69	$95
2013	$200	$67.75	$84

[1]U.S. Geological Survey, Helium Statistics and Information, Mineral Commodity Summaries for Helium, available at: https://www.usgs.gov/centers/national-minerals-information-center/helium-statistics-and-information

5. Two of the influences in the helium sector are noteworthy for understanding the helium market.
    a. There is no substitute for helium's unique properties in gaseous and liquid form for the sectors that rely on helium use.
    b. The Helium Stewardship Act of 2013 required the privatization of the decades-old federal helium reserve. Auctioning the federal reserve concluded in 2024. Former helium pricing metrics used by BLM's operation and sales from the federal reserve are now no longer part of the helium market.

U.S. Geological Survey, Mineral Commodity Summaries 2024
https://pubs.usgs.gov/periodicals/mcs2024/mcs2024.pdf and
https://www.usgs.gov/centers/national-minerals-information-center/mineral-commodity-summaries

3.0 Minnesota Environmental Quality Board

Environmental Review

3.1 Environmental Assessment Worksheet as Threshold Information

1. The Environmental Assessment Worksheet (EAW) represents an existing framework to obtain threshold information for a proposed operation.
2. Operator responses to the EAW can provide information necessary for review to issue a Development Permit and any site-specific permit conditions.
3. Information for the EAW would fall into two categories: operations and environmental, consistent with the current EAW form.
4. The Responsible Governmental Unit (RGU) retains discretion to make a finding that an Environmental Impact Statement is indicated, rather than an EAW, only.

3.2 Action Triggering EAW

1. The action triggering an EAW would be a request to DNR for a Development Permit.
2. An EAW completed by the operator can accompany the request for a Development Permit as baseline information.
3. The Development Permit and associated Drilling Permit would not be issued without EAW review and site-specific permit conditions resulting from information provided in the EAW or through DNR's independent review.

3.3 Timing for EAW Requirement

1. Submittal of the EAW can be concurrent with a request to DNR for a Development Permit.
2. The format of the request to DNR for a Development Permit will be determined by the agency. It may consist of a Development Permit application form and accompanying attachments.
3. The request to DNR for a Development Permit would make DNR the likely RGU for an EAW.
4. The EAW and Development Permit would be required prior to disturbing a new surface location to drill a gas well or install production equipment related to the gas well.
   a. Exploration wells would be considered gas wells subject to a Development Permit, regardless of whether the well was found to have economic volumes of gas for production.
5. The EAW content could use the existing EAW with modifications to better align with a gas operation.

3.4 Scope of Operations Subject to EAW

1. The scope of operations subject to the EAW can be all of the area disturbed for a well pad and all the operations at the well pad for exploration, production, treatment, and processing of gas, including:
   a. Production equipment consisting of surface equipment, and the flowlines on the well pad connecting the surface equipment, during the life of the well or processing operations on the pad
   b. Processing operations consisting of equipment on the well pad to separate, purify, compress, and store gas from the well and any liquids
   c. Flowline(s) and associated disturbance from the well pad to processing operations at another location

d. Access road from the public road to the well pad

2. A stand-alone processing operation at another location would be regulated as an industrial facility, consistent with the regulation of other industrial facilities in the state, rather than subject to a Development Permit.

3.5 Modifications Needed to Current EAW Form

1. EAW (December 2022) is currently in circulation. Suggested modifications to the form are shown in the table below.

Section	Suggested Modification to EAW
1	• Change *Project title* to *Name of Operation* • Use operation throughout the EAW
2	• Change *Proposer* to *Operator* • Add line item for the company name of the operator
4	• Eliminate column for discretionary EAW
5	• Replace the requirement for *general* location with *proposed* location • For site plans, list the minimum information required to be shown: disturbed area and acreage; well pad and acreage; access from public road and length; flowline to processing operations at another location and length; setbacks from features identified by the EAW; equipment during well drilling and completion; equipment during production; stormwater controls
6b	• List a requirement for the estimated schedule and duration for construction, well drilling and completion, well testing, well shut in, and production • List a requirement to describe or illustrate process flow during production from the wellhead through the operator's final disposition of gas • List a requirement to describe the operations on the well pad, access road, flowline, stormwater control design, and power source during production • List a requirement to describe the equipment type and volume during well drilling and completion and during production, including any air pollution control and spill prevention
6c	• List a requirement to describe potential full buildout on the well pad • Detailed information for full buildout not otherwise provided in Section 5, 6b, and subsequent sections of the EAW would require amendment to the Development Permit and a new EAW
6d	• List a requirement to declare the mineral resource targeted for drilling and production from the well
6e	• List a requirement to describe where gas processing through the operator's final disposition of the gas will occur

Section	Suggested Modification to EAW
7	• May be addressed by other EAW sections
10	• List a requirement to show residential and non-commercial buildings within a designated distance from the proposed well pad • List a requirement to demonstrate a surface lease for surface use of the land
11b	• List a requirement to provide the anticipated schedule, size, revegetation plan, and stormwater controls to downsize the area of disturbance after well drilling is complete
12b	• List a requirement to provide anticipated volume, storage, and disposal of formation water during well drilling • List a requirement to provide anticipated volume, storage, and disposal of produced water for the life of the well • Sections can be edited for applicability to gas well development
13	• List a requirement for the type, volume, storage, and disposal of exploration and production waste, including drilling fluid, drill cuttings, cement returns, excess cement, tank bottoms, oily waste, well treatment chemicals, plugging fluids, and general domestic wastes
20	• List a requirement to quantify the number of days per week a site operator will be on location to inspect and maintain the location • List a requirement to quantify the number of truck trips per week to offload liquids or compressed product from the location
21b	• Indicate that reasonably foreseeable future projects can include gas processing operations at another location under the control of another operator

4.0 Minnesota Department of Health

Drilling Permit

4.1 When a Drilling Permit is Required

1. A Drilling Permit would be required prior to drilling a gas well
2. A Drilling Permit would be required prior to re-entering a plugged well
3. A Drilling Permit or amendment to an approved Drilling Permit would be required to deepen or complete a drilled well.

   Colorado Energy & Carbon Management Commission, Rule 308.a
   https://ecmc.state.co.us/documents/reg/Rules/LATEST/300%20Series%20-%20Permitting%20Process.pdf

4. A water well or stratigraphic well used for exploration or production of gas would require a Drilling Permit.
   a. If a test for gas or fluid productivity is made in a water well or stratigraphic well, the well would be reclassified as a gas well subject to a Drilling Permit.
   b. Montana states "If a test for fluid productivity is made in a stratigraphic well or core hole, the well must be reclassified as 'wildcat or exploratory' and is subject to all the rules of a well drilled for oil or gas."
   c. Likewise in Montana, wells drilled in a delineated field to known productive horizons cannot be classified as stratigraphic wells.

   Montana Board of Oil and Gas Conservation, Rule 36.22.303
   https://rules.mt.gov/browse/collections/aec52c46-128e-4279-9068-8af5d5432d74/policies/06b92f4b-42bc-48fd-94f7-3b037b1c169b

4.2 Construction Engineering

1. The operator would be required to identify:
   a. Mineral ownership (e.g., fee, state)
   b. Mineral leasehold (to qtr qtr and acres)
   c. In Utah at Rule 649-3-4.2.4, operators must provide a plat prepared by a licensed surveyor or engineer showing:
      1) The well's Public Land Survey System (PLSS) quarter-section or lot, section, township, range, and principal meridian
      2) Latitude and longitude coordinates for the well's surface and terminus locations
      3) Bearing and distance from the well's surface to its terminus location and from the surface and terminus locations to PLSS section lines
      4) Coordinate reference system
   d. In Colorado, the plat must show ground elevation
   e. Formation names, top depth, bottom depth
   f. Well type (vertical versus directional)
   g. Any proposed hydraulic fracturing

h. Whether salt sections are anticipated

i. Blowout prevention equipment

j. Total depth

1) Surface hole location

2) Bottom hole location

k. Drilling fluid type

l. Closed loop drilling

1) In Colorado at Rule 408.a, closed loop drilling is required except where only water-based bentonitic drilling fluids are used and the well will not penetrate salt-bearing formations.

2. Include waste disposal for drilling fluid, drill cuttings, cement returns, excess cement, tank bottoms, oily waste, well treatment chemicals, plugging fluids, and general domestic wastes addressed with surface use by the EAW submitted with the Development Permit.

4.3 Casing and Cementing

1. As a general requirement, casing and cementing is intended to prevent migration of gas and water from one formation to another behind the casing and to isolate groundwater penetrated by the well.

2. Casing and cementing requirements vary by state and show a continuum of requirements.

   a. Groundwater requirements, for example, range from casing to 50 feet below groundwater classified for domestic use, agricultural use, protection, or useable quality (Colorado) to casing 100 feet below all fresh water strata (Michigan).

   b. Centralizer requirements range from specific for every fourth joint for surface casing (Colorado) to the general requirement for spacing to maintain the casing annulus throughout the cased interval (Wyoming).

   c. Cementing requirements range from designating free water separation less than or equal to 3 mm per 250 mm of cement (Colorado) to designating only adherence to API standards (Wyoming).

3. In Colorado, casing and cementing requirements are found at Rule 408.

   In Michigan, casing and cementing requirements are found at Rule 324.

   In Montana, casing and cementing requirements are found at Rule 36.22.1001.

   In Utah, casing and cementing requirements are found at Rule 649-3-8.

   In Wyoming, casing and cementing requirements are found at Rule 055.0001.3.

4. Variation seen in state requirements tends to have a basis in local conditions. For example, protection may be put in place for critical groundwater. Or state engineers map apply their differing experience with results observed from cementing programs. Or local geology and geologic strata may affect additives and bonding in cement and drive specifications. Or compressive strength in cement may vary by well depth.

5. In general, although certain states (such as Kansas) may demonstrate specifications similar to Colorado, Colorado specifications illustrate a comprehensive model.

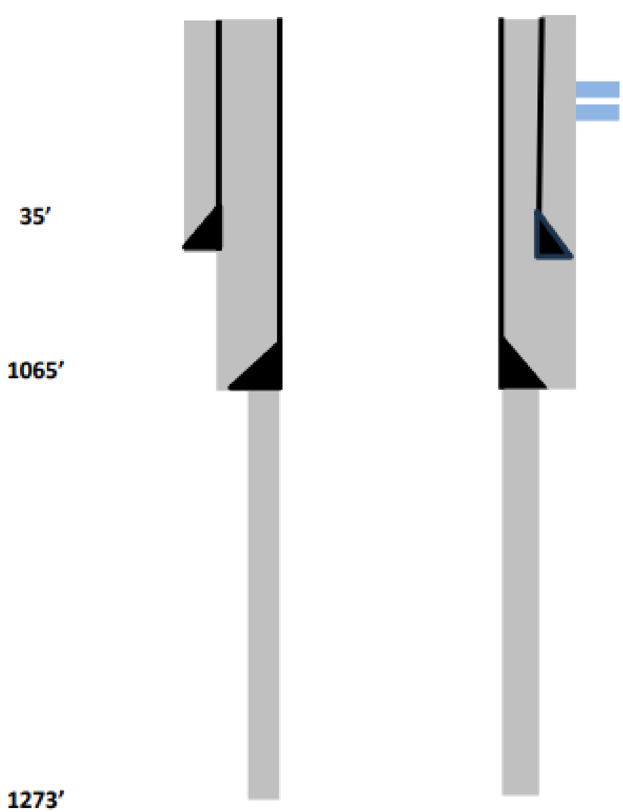
6. For additional support with casing, the American Society of Mechanical Engineers provides a reference for specifications.
7. For additional support with cementing, cement companies supplying oil and gas operations may provide a resource for expertise and an in-house database of cementing procedures across states.
8. Some jurisdictions (commonly counties) will conduct technical reviews requiring specialization with support from consulting engineers.
9. Below is an example illustration for reporting casing programs and wellbore diagram.

CASING PROGRAM

Casing Type	Size of Hole	Size of Casing	Grade	Wt/Ft	Csg/Liner Top	Setting Depth	Sacks Cmt	Cmt Btm	Cmt Top
CONDUCTOR	20+0/0	16+0/0	A500	52.49	0	10	10	10	0
SURF	12+1/4	8+5/8	J-55	24	0	630	400	630	0
1ST	7+7/8	5+1/2	J-55	15.5	0	6300	400	6300	3000
	7+7/8	5+1/2	J-55	Stage Tool		3000	250	3000	0

CASING PROGRAM

Casing Type	Size of Hole	Size of Casing	Grade	Wt/Ft	Csg/Liner Top	Setting Depth	Sacks Cmt	Cmt Btm	Cmt Top
CONDUCTOR	17+1/2	13+3/8	J-55	48	0	35	14	35	0
SURF	12+1/4	9+5/8	J-55	36	0	1065	196	1065	0
OPEN HOLE	8+3/4				1065	1273			



GL: ~5,548'

← Conductor Casing
13 3/8" 48# J-55 casing set at 35'. Cemented in a 17 1/2" hole with 14 sacks of 15.5# / 1.16 yield class G neat Cement to Surface.
Hole depth 35'

← Surface String
9 5/8" 36# J-55 Casing set at 1065'. Cemented in a 12 1/4" hole with 196 sacks of 15.5# / 1.16 yield class G neat Cement to surface. Hole depth 1065'

← Open Hole
Drill 8 ¾" open hole to 1273', Plan to produce from open hole.

TD of 1273'

Colorado Energy & Carbon Management Commission, Rule 408
https://ecmc.state.co.us/documents/reg/Rules/LATEST/400%20Series%20-%20Operations%20and%20Reporting.pdf

Michigan Geologic Resources Management Division, Rule 324
https://dtmb.state.mi.us/ORRDocs/AdminCode/1889_2019-001EQ_AdminCode.pdf

Montana Board of Oil and Gas Conservation, Rule 36.22.1001
https://rules.mt.gov/browse/collections/aec52c46-128e-4279-9068-8af5d5432d74/policies/9d86865b-b701-4323-a1bc-fb92ca29b565

Utah Division of Oil, Gas and Mining Rule 649-3
https://adminrules.utah.gov/public/rule/R649-3/Current%20Rules?searchText=R649

Wyoming Oil & Gas Conservation Commission, Rule 055.0001.3
https://rules.wyo.gov/Search.aspx?mode=1

4.4 Well Integrity

1. Colorado requires at Rule 408 pressure testing the surface and intermediate casing to a minimum 1,500 pounds per square inch (psi) and the production casing to a minimum 500 psi greater than the maximum anticipated surface pressure.
    a. The operator must submit results for integrity testing, a cement bond log, and a resistivity log to describe the stratigraphy of the wellbore.
2. Wyoming requires at Rule 055.0001.3 pressure testing to a surface pressure of 1,500 psig.
    a. The operator must submit results for integrity testing and a cement bond log.

Colorado Energy & Carbon Management Commission, Rule 408
https://ecmc.state.co.us/documents/reg/Rules/LATEST/400%20Series%20-%20Operations%20and%20Reporting.pdf

Wyoming Oil & Gas Conservation Commission, Rule 055.0001.3
https://rules.wyo.gov/Search.aspx?mode=1

4.5 Well Plugging

1. The Drilling Permit application can include planned plugging and abandonment procedures.
2. The purpose of a plan to properly and permanently plug and abandon the well is to prevent potential environmental and safety concerns from unmonitored and non-producing wells.
3. Proper well closure also facilitates restoration of the surface location.
4. The financial assurance for the well would not be released until proper well plugging, abandonment, and surface reclamation have been verified.
5. Multiple states, such as Colorado, Kansas, Michigan, Montana, North Dakota, and Wyoming, evidence a common baseline for plugging requirements:
    a. Abandonment notice
    b. Cementing
    c. Removal of surface equipment
    d. Site reclamation

e. Abandonment report

f. Bonding

6. In Colorado at Rule 406.e for an abandoned conductor:

   a. Once a conductor pipe is set, if the well is not drilled within 3 months for cropland or 6 months for non-cropland, the well must be plugged.

   b. The conductor pipe must be cut 4 feet below ground level.

   c. The conductor pipe must be filled with clean inert material

   d. The conductor pipe must be sealed with a cement plug, screw cap, or cement plug and welded steel plate.

   e. The hole must be backfilled to ground level.

7. In Colorado at Rule 434.a for an abandoned well:

   a. Once a drilled well become inactive, it must be plugged and abandoned within 6 months.

      1) In Kansas, Montana, and Wyoming this timeframe increases to 1 year.

   b. The wellbore must be static before setting a plug.

      1) Wellbore fluids must be circulated to balance or overbalance the producing formation.

   c. The operator must pump cement plugs, with any plug a minimum 100 feet long and extending a minimum 100 feet above each zone to be isolated.

      1) In Kansas, the required lengths are 50 feet.

   d. Between cement plugs, the operator must fill the bore with water, mud, or other approved fluid.

   e. Cement design standards are listed at Rule 434.a.(1).

      1) In Wyoming, operators are referred to API standards for the class of cement and additives

   f. Abandonment procedures and marking at the surface are listed in Rule 434.a.(5).

Colorado Energy & Carbon Management Commission, Rule 400
https://ecmc.state.co.us/documents/reg/Rules/LATEST/400%20Series%20-%20Operations%20and%20Reporting.pdf

Kansas Corporation Commission, Rule 82-3-1010
https://www.kcc.ks.gov/images/PDFs/oil-gas/conservation/cons_rr_091615.pdf

Montana Board of Oil & Gas Conservation, Rule 36.22:
https://rules.mt.gov/browse/collections/aec52c46-128e-4279-9068-8af5d5432d74/sections/938ab68e-ff7e-4a24-b69f-1eccc48453b2

Wyoming Oil & Gas Conservation Commission, Rule 055.0001.3, Section 18
https://rules.wyo.gov/Search.aspx?mode=1

4.6 Blowout Prevention

1. Operators are expected to take all necessary precautions to maintain control of the well throughout all phases of operation (drilling, deepening, re-entry, re-completion, workovers, production, and plugging).
    a. Control of the well requires measures to prevent uncontrolled releases (blowouts) using equipment appropriate to the well, installation, and testing.
2. Helium gas wells may experience pressures significantly lower than a hydrocarbon gas well. Like the rules listed below, the operator can indicate the anticipated pressures and corresponding equipment.
3. In Colorado at Rule 603, the operator must indicate the type of blowout prevention equipment (“BOPE”) in the drilling application.
    a. The operator must also indicate any known subsurface conditions, such as an under or over-pressured formation.
    b. The blowout prevention equipment working pressure must exceed the anticipated surface pressure, assuming a pressure gradient of 0.22 psi per foot.
4. In Wyoming at Rule 055.0001.3, Section 23, blowout prevention equipment must be based on known or anticipated subsurface pressure, geologic conditions, or accepted engineering practice
    a. Wyoming, like Colorado, provides a standard for estimating the pressure to be contained at the surface of 0.22 psi per foot.
    b. Wyoming rules specify requirements for installation and testing.
5. Montana requirements for blowout prevention at Rule 36.22.1014 are linked below.

Colorado Energy & Carbon Management Commission, Rule 603
https://ecmc.state.co.us/documents/reg/Rules/LATEST/600%20Series%20-%20Safety%20and%20Facility%20Operations%20Regulations.pdf

Montana Board of Oil & Gas Conservation, Rule 36.22:
https://rules.mt.gov/browse/collections/aec52c46-128e-4279-9068-8af5d5432d74/policies/de9b4283-bf47-4cc9-b2d5-86103e3da0ea

Wyoming Oil & Gas Conservation Commission, Rule 055.0001.3, Section 23
https://rules.wyo.gov/Search.aspx?mode=1

5.0 Minnesota Pollution Control Agency

Air Emissions

5.1 Venting and Flaring

1. Colorado example for the well:

   a. ECMC rules prohibit venting or flaring gas during production. Venting or flaring under the circumstances below may be approved by the Director:

      1) During drilling, operators may vent with procedures for providing verbal notification to ECMC if capturing or combusting gas poses a safety risk to onsite personnel.

      2) During completions, operators may flare gas under an approved Gas Capture Plan with written approval from ECMC, including requirements to explain why flaring is necessary; protect public health and safety; estimate the flaring volume and duration; and direct gas to an emission control device for combustion if necessary.

   Colorado Energy & Carbon Management Commission, Rule 903
   https://ecmc.state.co.us/documents/reg/Rules/LATEST/900%20Series%20-%20Environmental%20Impact%20Prevention.pdf

2. New Mexico example for the well:

   a. Venting or flaring natural gas during drilling and completion is generally prohibited but may be done under certain circumstances.

   b. In all cases, flaring is preferred over venting except when (i) flaring is technically infeasible or would pose a risk to safe operations or personnel safety and (ii) venting is a safer alternative than flaring.

   c. During drilling in an emergency situation or malfunction, the operator may vent natural gas to avoid risk of an immediate and substantial adverse impact on safety, public health, or the environment.

      1) “Natural gas” is defined as “a gaseous mixture of hydrocarbon compounds, primarily composed of methane, and includes both casinghead gas and gas as those terms are defined in 19.15.2 NMAC." Based on this definition, the New Mexico regulations on venting and flaring may not apply to helium gas with a low hydrocarbon percentage.

   New Mexico Oil Conservation Division, N.M. Admin. Code 19.15.27.8, NMAC 19.15.27.7O
   https://www.srca.nm.gov/parts/title19/19.015.0027.html

3. Kansas example for the well:

   a. Operators may flare, vent, or use gas in any manner as authorized by regulations of the Kansas Corporation Commission, depending on the type of gas:

      1) Casinghead gas less than 25 mcfd may be vented or flared if (1) the gas volume is uneconomic to market due to pipeline or marketing expenses and (2) the operator made a diligent effort to obtain a market for the gas.

      2) Casinghead gas greater than 25 mcfd may be vented or flared considering (1) the availability of a market or of pipeline facilities; (2) the probable recoverable gas reserves; (3) the necessity for maintenance of reservoir gas pressure to maximize recoverability; (4) the feasibility of reinjecting the gas; and (5) other factors.

3) Sour casinghead gas is gas high in hydrogen sulfide (H2S) and may be flared considering (1) the availability of a market or of pipeline facilities; (2) the probable recoverable gas reserves; (3) the necessity for maintenance of reservoir gas pressure to maximize recoverability; (4) the feasibility of reinjecting the gas; (5) any anticipated change in the gas-to-oil ratio; (6) the H2S content of the gas; (7) the feasibility of desulfurization of the gas; and (8) other factors.

4) Natural gas may be vented or flared if necessary for any of the following: dewatering or well cleanup; well testing; well cleanup after stimulation or workover; evaluation and testing before connecting to a pipeline; emergencies; or as otherwise permitted by statute.

Kansas Corporation Commission, Rule 82-3-208
https://www.kcc.ks.gov/images/PDFs/oil-gas/conservation/cons_rr_091615.pdf

4. Colorado example for storage tanks

   a. Storage tanks with uncontrolled actual emissions of volatile organic compounds (VOCs) equal to or greater than 2 tons per year (tpy) based on a rolling 12-month total must collect and control emissions.

   b. Emissions must route from each storage tank to operating air pollution control equipment that achieves a hydrocarbon control efficiency of 95 percent. Use of a combustion device must have a design destruction efficiency for hydrocarbons of at least 98 percent.

   c. Venting is not allowed from a thief hatch, pressure relief device, or other access to the tank during normal operation, unless venting is reasonably required for maintenance.

   d. If air pollution control equipment is not installed by the compliance date, the operator may shut in wells producing into that storage tank until the control equipment is installed and operational.

   e. If use of air pollution control equipment would be technically infeasible without supplemental fuel, the operator may apply for an exemption from control requirements, but monitoring requirements would still apply.

   f. Monitoring is required at the frequency below.

Storage Tank Uncontrolled Actual VOC Emissions (tpy)	Approved Instrument Monitoring Frequency
≥ 2 and ≤ 12	Semi-annually
> 12 and ≤ 50	Quarterly
> 50	Monthly

Colorado Air Quality Control Commission, Regulation No. 7 (5 CCR 1001-9)
https://drive.google.com/file/d/1P6pRmNYx5KwEK6qDReYFL11-K-URI33J/view

5. New Mexico example for storage tanks:

   a. New storage vessels with a potential to emit (PTE) equal to or greater than 2 tpy of VOC must have combined capture and control of VOC emissions with at least 95 percent control upon start up. Use of a combustion device must have a design destruction efficiency for hydrocarbons of at least 98 percent.

   b. Storage vessels with a thief hatch must be capable of opening sufficiently to relieve overpressure in the vessel and to automatically close once the vessel overpressure is relieved.

c. If a control device is not installed by the compliance date, the operator may comply by shutting in the well supplying the storage vessel and not resume production from the well until the control device is installed and operational.

d. The requirements do not apply to a storage vessel if the actual annual VOC emissions decrease to below 2 tpy.

e. Monthly inspection of the storage vessel must ensure compliance with control requirements. Audio, visual, olfactory (AVO) inspection must be conducted weekly.

New Mexico Environmental Improvement Board, N.M. Admin. Code 20.2.50.123
https://www.srca.nm.gov/parts/title20/20.002.0050.html

6. Federal NSPS OOOOb

   a. In March 2024, the U.S. Environmental Protection Agency (EPA) finalized federal New Source Performance Standards (NSPS) to reduce air pollution emissions, specifically VOC and methane, from the Crude Oil and Natural Gas source category ("NSPS OOOOb"). *See* 89 Fed. Reg. 16820 (March 8, 2024); 40 C.F.R. § 60.5360b *et seq*.

   b. NSPS OOOOb is applicable to affected facilities that began construction, reconstruction, or modification after December 6, 2022. *See* 40 C.F.R. § 60.5365b.

   c. The types of source categories regulated by NSPS OOOOb include process controllers (previously referred to as pneumatic controllers), pumps, centrifugal compressors, storage vessels, combustion control devices, and liquids unloading.

   d. Under the NSPS, a storage vessel affected facility is generally a tank battery that has the potential for VOC or methane emissions that is equal to or greater than either (1) 6 tpy VOC or (2) 20 tpy methane.

   e. The Operator must reduce VOC and methane emissions by at least 95 percent by routing emissions to a control device or process under requirements specified in the rule, or by using a tank with a floating roof.

   f. The rule allows for removal of a control device from a storage vessel if the operator maintains the uncontrolled actual VOC emissions at less than 4 tpy and the actual methane emissions at less than 14 tpy as determined monthly for 12 consecutive months.

   g. The operator must demonstrate compliance with the 95 percent reduction requirement by conducting performance tests in accordance with the control device testing requirements.

   U.S. Environmental Protection Agency, 40 C.F.R. § 60.5395b ("NSPS OOOOb")
   https://www.ecfr.gov/current/title-40/chapter-I/subchapter-C/part-60/subpart-OOOOb/section-60.5395b

5.2 Stationary Engines

1. Engines for drilling and production are likely to be used for the following:

   a. Non-road internal combustion engine on the drill rig

   b. Non-road internal combustion engine on the completions rig

   c. Stationary source engine(s) powering air compressors

   d. Stationary source engine(s) powering helium processing equipment when grid power is unavailable

2. Rig engines typically use diesel fuel to supply the rig generator and provide sufficient power for drilling. Air emission controls range from Tier II to IV, depending on the age of the drill rig and rig availability. The rigs are regulated as non-road engines.
    a. Certain rigs are capable of lowering emissions by running on dual fuel or by using natural gas from the well.
    b. Certain rigs are capable of lowering emissions by running on electricity from the power grid, which requires a specialized transformer connecting to the rig's powerhouse.
    c. In general, the duration for drilling and completing a relatively shallow gas well in an area that is in attainment for National Ambient Air Quality Standards can provide for flexibility in the emission controls required for the drilling and completions rigs.
3. During well drilling, stationary engines may be used to power air compressors used for drilling.
4. During production, stationary engines may be used to power helium processing equipment when no grid power is available.
    a. Stationary engines during production are more likely to be powered by natural gas or propane.
5. Stationary engines are already regulated in Minnesota by PCA depending on the source's PTE as a product of engine make and model, fuel type, fuel use, horsepower, displacement, emission controls, and assumption of operating hours (8,760 hours per year).

5.3 Odor Control

1. Gas wells drilled with water-based drilling fluid ("mud") or air would typically not have the nuisance odors that might be associated with operations using oil-based drilling fluids and oil tank storage.
2. Nuisance odors can be further controlled in the following ways:
    a. Closed-loop system during well drilling to reuse drilling fluid
    b. Fluid storage in steel tanks, which are removed from the location after well drilling for off-site disposal
    c. Drill cutting storage in steel tanks, which are removed from the location after well drilling for off-site disposal
    d. When oil-based mud is used (e.g., for salt sections in the formation), the oil-based mud that is not part of the active mud system would be stored in closed upright tanks
    e. Prohibition on burning debris and trash
    f. Liquids stored during production would use enclosed tanks maintained with closed thief hatches
    g. Operators would comply with local nuisance ordinances

5.4 Noise Control

1. Gas wells would typically not have nuisance levels of noise when drilled (1) in a rural area distanced from homes and businesses, (2) over a relatively short duration for a conventional vertical well, and (3) without hydraulic fracturing.
2. Nuisance noise can be further controlled in the following ways:
    a. Perform an estimate of sound levels at the nearest receptors, where sound levels in a rural residential area may be expected in the range of 50 to 60 decibels measured in dBA

b. Compliance with a local ordinance establishing daytime and nighttime noise limits

c. Installation of a sound wall during well drilling in the direction of receptors, if needed

d. Installation of enclosures for long-term use of generators during production

e. Electrification of the site to connect powered equipment to the electric grid during production, in lieu of generator use

3. Colorado and New Mexico establish numeric limits for noise based on land use and time of day.

Colorado Energy & Carbon Management Commission, Rule 423
400 Series - Operations and Reporting.pdf (state.co.us)

New Mexico Oil Conservation Division, Rule 802.a
COGCC_800_Series_VF_Current.pdf (nm.gov)

Water Discharges

5.5 Disposing of Formation Water

1. During well drilling, water may be present in the formation ("formation water").
2. Water brought to the surface from the well as formation water would typically be stored at the surface in tanks.
3. Tanks commonly in use during well drilling are 500-barrel (bbl) open-topped rectangular steel "frac tanks."
   a. 500 bbls is equivalent to approximately 21,000 gallons.
4. Formation water would have a composition unique to the gas reservoir and may contain suspended solids, dissolved solids, soluble and insoluble organics, and hydrocarbons.
5. Formation water may also contain technologically enhanced naturally occurring radioactive material (TENORM). Technologically enhanced refers to the human-caused exposure or concentration of radioactive material not otherwise exposed to the surface.
6. Disposing of formation water during well drilling, like produced water during production, would require piping or trucking off-site to a facility approved to accept the waste, which is discussed further below.

5.6 Disposing of Produced Water

1. After well drilling, water may continue to be present in the formation.
2. Water brought to the surface from the well as produced water would typically be separated from the gas stream using a two-phase separator for water and gas.
   a. If oil was present in the formation, the streams would typically be separated using a three-phase separator or a heated separator to separate water, gas, and oil.
3. Produced water is commonly stored in aboveground storage tanks, ranging from 200 bbls to 300, 400, or 500 bbls.
4. Minnesota PCA regulates aboveground storage tanks, except at Section 115.03 in Minnesota statute where tanks are used for storing liquids that are gaseous at atmospheric temperature and pressure.

   a. Produced water is not gaseous at atmospheric temperature and pressure, although the tank may experience breathing loss of hydrocarbons from changes in temperature or pressure.

5. Methods for disposal of formation water and produced water from a well include (1) injection well, (2) surface discharge, (3) pretreatment and disposal at a publicly owned treatment works (POTW), and (4) land application.
   a. Oil and gas producing states rely predominantly on injection well disposal.
6. Injection wells
   a. Minnesota has determined that use of injection wells for oil and gas-related disposal or injection is not prohibited under Rule 4725.2050 administered by MDH.
   b. However, Minnesota has not been delegated primacy by EPA for regulation of oil and gas-related Class II "Underground Injection Control" (UIC) wells.
   c. Class II injection wells in Minnesota would be regulated directly by EPA (direct implementation) under federal rules implementing the Clean Water Act.
   d. EPA provides a *Class II Permit Application Completeness Review Checklist* summarizing the information required from an applicant for mapping; geological data; formation testing; well construction; injection operation; injection monitoring; plugging and abandonment; and financial assurance.
   e. One opportunity in Minnesota would be pairing a state-issued Development Permit for the surface location with an EPA-issued Class II UIC permit for the injection well to protect surface and subsurface resources.
   f. In the neighboring states of North Dakota and South Dakota, Class II injection wells are regulated by the North Dakota Department of Mineral Resources and the South Dakota Department of Agriculture & Natural Resources.
      a. Class II injection wells in neighboring states present an opportunity for trucking formation water and produced water out of state for disposal.

   U.S. Environmental Protection Agency, UIC Class II Permit Application Completeness Review Checklist
   https://www.epa.gov/sites/default/files/2019-08/documents/solution_2.2_-_class_ii_administrative_review_checklist_draft_final.pdf

7. Direct discharge
   a. Direct discharge of produced water potentially would be regulated according to federal New Source Performance Standards for onshore oil and gas extraction under EPA effluent limit guidelines at 40 Code of Federal Regulations (CFR) Part 435, Subpart C.
8. Pretreatment
   a. Pretreatment and discharge of produced water from an *unconventional* oil and gas well (e.g., tight shales) to a POTW is prohibited under 40 CFR Part 435.34.a. In its guidance, EPA states that POTWs are not designed to treat constituents present in the effluent.
   b. Rules regarding pretreatment and discharge of produced water from a *conventional* oil and gas well to a POTW is currently reserved for future federal rulemaking at 40 CFR Part 435.34.b.

9. Land application
    a. Land application of produced water is regulated in multiple states, such as New Mexico, Texas, and Wyoming.
    b. Land application can be associated with environmental degradation from salts, measured as sodium absorption ratio and electrical conductivity, and the associated potential impacts to soil productivity, vegetation, surface water and groundwater.
    c. To protect the land surface, surface water, and groundwater, regulatory programs review wastewater quality and waste loading, application method, application rate, soil characteristics, topography, runoff control, and depth to groundwater.

5.7 Use of Pits

1. Anticipated waste streams may include drilling fluid, drill cuttings, formation water, cement returns, excess cement, produced water, tank bottoms, oily waste, well treatment chemicals, plugging fluids, and general domestic wastes.
2. Advance planning for waste disposal is particularly important for an area without an existing oil and gas sector and a commercial sector established to serve oil and gas sector waste disposal.
3. The EAW provides a means to require the operator's plan for waste disposal for each anticipated waste stream.
4. *Off-site* waste disposal at facilities approved to accept the waste would typically be the preferred method of disposal.
5. The method for waste disposal, including any requirement for off-site waste disposal, could be a provision in the Development and Drilling Permits.
6. At some well sites, operators may seek approval to excavate a pit to serve as a temporary holding area for waste fluids or approval to excavate a trench for permanent disposal for drill cuttings.
    a. Trenches for drill cuttings typically are unlined to allow drill cuttings to dewater and dry for burial.
    b. Pits for waste fluids typically are lined to prevent contamination of soil and groundwater.
7. When pits are allowed, prohibitions may be placed on areas with shallow groundwater, in floodplains, or with nearby residences.
8. Drill cuttings burial on site is allowed in Colorado only when the drill cuttings meet concentration limits for pollutants listed in Table 915-1 after composite sampling.
9. Pits used for waste fluids in Colorado must meet construction, liner, and closure requirements at Rules 909-911.
10. States vary as shown below in stringency for pits used for waste fluids.
    a. Required pit freeboard in Colorado at Rule 909.c is 2 feet. Required pit freeboard in Kansas at Rule 82-3-601a.(a) is 1 foot.
    b. Colorado requires at Rule 910.a that all new pits are lined. Kansas at Rule 82-3-600.(f)(2) requires a liner if the commission determines that an unsealed condition presents a pollution threat to soil or water.
    c. Colorado requires at Rule 910.c.(1) lining using a synthetic material. Kansas at Rule 82-3-601.a.(b) allows for liners to be composed of soils mixed with clay and bentonite.

11. Consistent with rules in Kansas, Wyoming rules at Rule 055.0001.4.w require liners under specific conditions, such as locations in fill, sandy soil, or areas with shallow groundwater. Liners can include clay mixtures. In Wyoming, freeboard is not quantified. Instead, the pit must be designed for extreme precipitation.
12. In general, states consistently specify rules for waste characterization, pit construction, natural or synthetic liner installation, hydraulic conductivity, leak detection, and closure.

    Colorado Energy & Carbon Management Commission, Rules 909-911, Table 915-1
    https://ecmc.state.co.us/documents/reg/Rules/LATEST/900%20Series%20-%20Environmental%20Impact%20Prevention.pdf

    Kansas Corporation Commission, Rule 82-3-600
    https://www.kcc.ks.gov/images/PDFs/oil-gas/conservation/cons_rr_091615.pdf

    Wyoming Oil & Gas Conservation Commission, Rule 055.0001.4.w
    https://rules.wyo.gov/Search.aspx?mode=1

5.8 Use of Water Tanks

1. For wells without formation or produced water, water at the site may only be the fresh water tanks used during well drilling and cementing.
2. Alternatively, an operator's water tank may refer to formation water during well drilling that is stored temporarily before off-site disposal.
3. An operator's water tank may also refer to one or more water tanks used to store produced water during production.
    a. Produced water may be present from the well during the life of the well.
    b. Or produced water may decline steeply after initial production.
4. A produced water tank will remain liquid at atmospheric temperature and pressure. A produced water tank should not be conflated with the exemption provided for compressed gas tanks.
5. Operators refer to tank volumes in barrels (bbls), typically ranging from 200 bbls to 300, 400, or 500 bbls, where 1 barrel is approximately 42 gallons.
6. Minnesota PCA already regulates aboveground storage tanks (ASTs) under regulations likely applicable to produced water tanks at Minnesota Administrative Rule 7151.

6.0 Residual Questions and Answers

Minnesota Department of Natural Resources

How are States Structured for Oil and Gas Regulatory Bodies?

Each oil and gas state reviewed has an organizational structure designated for administration of oil and gas rules. Less than one-third are independent bodies of the executive branch. The others are regulatory agencies under the executive branch.

Independent bodies of the executive branch:

Montana Board of Oil & Gas Conservation[1]

Nebraska Oil & Gas Conservation Commission

Wyoming Oil & Gas Conservation Commission

Regulatory agencies under the executive branch:

Colorado Energy & Carbon Management Commission, Department of Natural Resources

Kansas Oil & Gas Conservation Division, Kansas Corporation Commission

Michigan Geologic Resources Mgmt. Division, Dept. of Environment, Great Lakes, and Energy

New Mexico Oil Conservation Division, Energy, Minerals and Natural Resources Department

North Dakota Oil & Gas Division, Department of Mineral Resources

Pennsylvania Office of Oil and Gas Management, Department of Environmental Protection

South Dakota Minerals and Mining Program, Department of Agriculture & Natural Resources

Utah Division of Oil, Gas & Mining, Department of Natural Resources

[1]The Board states that it is attached to the Department of Natural Resources for *administrative* purposes

How are Oil and Gas Commissions Funded?

In oil and gas states, like Colorado and Kansas, commissions are not funded by appropriations from the general fund. Instead, they are largely fee funded by industry. In Colorado, for example, funding sources are a combination of a levy of 1.5 mills on oil and gas production; an operator fee for each well spud; an allocation from state severance taxes on oil and gas; and smaller funding streams from collected penalties, claimed financial assurance, and federal funds. An example of federal funds is a federal grant awarded in 2024 to plug methane-emitting oil and gas wells. In Colorado, the most recent fiscal year 2024 had an Energy & Carbon Management Commission budget of $32.5M.

Even in a smaller oil and gas state, like Nebraska, with a fiscal year 2024 budget of $1.7M, appropriation from the General Fund represented approximately 10 percent of the budget. The majority of funding was derived from industry and a small revenue stream from federal funds.

Minnesota Pollution Control Agency

Are There Anticipated Releases to the Atmosphere?

A helium well could be expected to produce nitrogen, CO_2, helium and, potentially, methane. Production may be free flowing gas or may include some amount of water from the underground formation. Processing equipment can provide for recovery of commercial grade CO_2 (e.g., used in the beverage industry) and helium. When CO_2 is not recovered for commercial sale, both nitrogen and CO_2 tend to be vented to the atmosphere. In states tracking greenhouse gases, such as Colorado, CO_2 emissions are an annual reporting requirement as part of a regulated source's annual emissions inventory. Methane gas in small volumes with no takeaway capacity (like a pipeline) can be routed on site to use as a fuel source for separation and processing equipment on the site. Or methane can be combusted in an enclosed combustor on the site with a greater than 98 percent destruction efficiency. See Section 1.6 for discussion of methane gas.

Is There Anticipated Long-term Storage of Gases in Tanks?

Gas in storage would be anticipated to be purified helium stored in iso tubes and loaded onto a semi-truck trailer for transport for commercial sale. See Section 2.2 for discussion of helium purification. Depending on production rates, a "tube trailer" may leave a site multiple days a week, which limits the time that iso tubes are stored on location. The iso tubes load horizontally on the trailer and are filled with inert, nonhazardous, and noncombustible compressed helium gas.

Is There Anticipated High-pressure Storage of Liquids in Tanks?

High-pressure tanks may be limited to iso tubes containing inert, nonhazardous, and noncombustible compressed helium gas. If formation water is encountered, it can be separated from the gas stream using a separator at the surface. The formation water can be stored in an enclosed tank at the surface at atmospheric pressure. Any gas vented from the tank can be captured for combustion in an enclosed combustor on site. Water from the tank can be off-loaded by truck and transported to a facility approved to accept the water for disposal. The water may be entrained with suspended solids, dissolved solids, soluble and insoluble organics, hydrocarbons, and possibly TENORMs. See Sections 5.1.4 and 5.5 for discussion of storage and regulation of gases and water using atmospheric storage tanks.

Is There Potential for a Small Quantity Generator for Hazardous Waste?

Wastes during well drilling (e.g., drill cuttings) and production (e.g., produced water and tank bottoms) are generally treated as federally exempt exploration and production ("E&P") waste under the federal Resource Conservation and Recovery Act, Subtitle C. Wastes not categorized as E&P wastes would be regulated under RCRA Subtitles C and D and corresponding state rules for waste management.

What is the Applicability of Federal Clean Air Act Section 112(r) to Operations?

Clean Air Act Section 112(r) requires a risk management program for certain stationary sources holding more than a threshold quantity of a regulated hazardous substance. In the implementing regulations at 40 CFR Part 68.115, exemptions are described at Part 68.115(b)(2)(iii) for naturally occurring hydrocarbon mixtures. According to the rule, these include any combination of condensate, field gas, and produced water. Irrespective of Clean Air Act Section 112(r), Minnesota regulatory requirements applicable to an operation may include generation of information in the Environmental Assessment Worksheet for the type, volume, storage, and disposal of exploration and production waste; state hazardous waste generator requirements; applicable Spill Prevention, Control, and Countermeasure Plan requirements; and any requirements imposed under a Development Permit for spill or release prevention, reporting, and response.

Is There Potential for Underground Storage Tanks?

During well development, temporary storage is expected to be above-ground. During production, a site with limited production facilities may be visited either daily or several days a week by outside personnel fueling their work vehicles off site. A site with production facilities to process helium may connect to grid power to power equipment. Without grid power, the site may use a combination of any recovered methane and imported fuel, like propane or natural gas (methane), to fuel generators. Those fuel tanks would likely be above ground and regulated consistent with state regulation for above ground storage tanks for fuel.

Is There Precedent for Well Driller Licensure?

Oil and gas well drilling does not appear to have the equivalent of states' requirement for the testing and licensure applicable to *water* well drillers. States like Texas emphasize that state licensure for water well drillers is in place to ensure construction integrity and safety for consumption from water wells. In the oil and gas sector, states may require licensure of the drill rig while otherwise using rules for casing, cementing, mechanical integrity, inspection, and reporting to govern the well driller and well.

Are Polyfluoroalkyl Substances Present in the Industry?

There is potential, for example, for on-site helium processing equipment to use fluoropolymer membranes for the separation of gases. Fluoropolymers are considered a type of polyfluoroalkyls (PFAS).

Conclusion

This Report of Best Practices does not identify singular best practices. Instead, it frequently provides multiple examples or continuums of practices that are seen across oil and gas producing states. Differences between states in their regulation of the oil and gas sector often reflect state-specific concerns, like population growth proximate to oil and gas development; air quality attainment status; prevalence of hydraulic fracturing in well drilling; sensitive groundwater resources; and other localized influences.

For each regulatory topic, the states or the number of states identified as precedents vary. The variation occurs because the focus is not on providing a fixed format for the report. Rather, the report provides models for regulatory practices most relevant to a topic. Given the many states and agencies identified in the report, the table below provides a collated list of agency links.

Regulatory Body	URL
COLORADO	
Energy & Carbon Management Commission, Department of Natural Resources	https://ecmc.state.co.us/#/home
ILLINOIS	
Oil & Gas Resource Management, Department of Natural Resources	https://dnr.illinois.gov/oilandgas.html
KANSAS	
Oil & Gas Conservation Division, Kansas Corporation Commission	https://www.kcc.ks.gov/oil-gas
MICHIGAN	
Geologic Resources Management Division, Dept. of Environment, Great Lakes, and Energy	https://www.michigan.gov/egle/about/organization/geologic-resources-management/oil-and-gas
MONTANA	
Board of Oil & Gas Conservation	https://dnrc.mt.gov/bogc/
NEBRASKA	
Oil & Gas Conservation Commission	https://nogcc.ne.gov/
NEW MEXICO	
Oil Conservation Division, Energy, Minerals and Natural Resources Dept.	https://www.emnrd.nm.gov/ocd/
NORTH DAKOTA	
Oil & Gas Division, Department of Mineral Resources	https://www.dmr.nd.gov/oilgas/
PENNSYLVANIA	
Office of Oil and Gas Management, Department of Environmental Protection	https://www.dep.pa.gov/Business/Energy/OilandGasPrograms
SOUTH DAKOTA	
Minerals and Mining Program, Department of Agriculture & Natural Resources	https://danr.sd.gov/Environment/MineralsMining/default.aspx
UTAH	
Division of Oil, Gas & Mining, Department of Natural Resources	https://ogm.utah.gov/og-home/
WYOMING	
Oil & Gas Conservation Commission	https://wogcc.wyo.gov/

Theme	Health_and_environmental_quality	Financial_assurance	Process
Health_and_environmental_quality	Worker safety	FA structure	There should be no temporary framework
Financial_assurance	Flaring	SBI investment of FA	Permits before full understanding
Process	Saline water		Poor track record
Tribal_relations	Hydraulic fracturing		Burdensome regulations
Environmental_review	Class II injection wells		Ethics standards
Pooling_orders	Need for solid waste permit		DNR conflicts of interest
Spacing_unit	Compliance monitoring		Consumption patterns
Tax_distribution	Violation fines		Timing of resource extraction
Revenue_generation			Need underground gas storage framework
Gas_production_permitting			Robust regulation
Data_sharing_public_data			Contested case and legal
Correlative_rights			Leasing
Gas_wells			Statutory language
			General

Tribal_relations	Environmental_review	Pooling_orders	Spacing_unit
Need for consultation	Need for comprehensive EIS	Shielding from pooling orders	Application process
Usufructuary rights	Tribal consultation within ER	% of owner consent	Who proposes spacing units
	No mandatory EAW for exploration	Agency authority	Size and shape
	MPCA should be RGU	Application process	Property line setbacks
	General	Compensation for nonconsenting owners	General
	Need for baseline data	Rights of nonconsenting owners	Legal challenge process
	Need to define mandatory category thresholds	Risk penalty	
	EAW and EIS costs	General	
	Siting and setbacks	Legal challenge process	
	Alternative site analysis		
	Radioactive materials		
	Environmental impacts		
	Carbon and climate change		
	Traffic and roads		
	Noise / light		

Tax_distribution	Revenue_generation	Gas_production_permitting	Data_sharing_public_data
Different tax rates	Tax exemptions	Permit fees duplicated to Tribes	Pre-production report should go to Tribes
General	Tax rates	Permit fees too high	Company proprietary data
Tax proceeds to Tribes	Need for economic analysis	Permit fee transparency	
		Reclamation fees	
		Temporary permits	
		Need for all required permits	
		Permit length	
		General	
		When is a permit needed	
		Storage, transfer and delivery	
		Induced hydrogen	
		Mine permitting not best model for gas permitting	

Correlative_rights	Gas_wells
General	Well setbacks
	Well construction
	Well inspection
	Regulatory oversight
	Notifications
	Contractor licensing
	Exploratory borings

Comment number	Comment	Theme	Sub-theme
002	Oftentimes, the gas reserves found underground are in high pressure environments and of unknown volume. We have safety concerns regarding situations where an underground mine accidentally strikes one of these large pockets of high-pressure gas, flooding the underground mine with gas that may detrimentally impact mine workers due to limited ventilation below ground. From our quick review of the proposed regulatory language, there seems to be no language to protect workers in that work environment.	Health_and_environmental_quality	Worker safety
003	Like water, the nature of gas is diffuse, moving throughout porous spaces in the underlying geology. Consequently, we view gas resources differently from hard-rock resources. We believe that it is naive for the State to assume that gas resources have similar properties as non-ferrous hard-rock resources. Consequently, modeling a regulatory framework, whether temporary or final, on regulatory structures that apply to non-ferrous hard-rock resources raises significant substantive concerns. Assuming there will be similarities between hard-rock resources and gas resources misconstrues the differences between hard-rock extraction and gas extraction, and their geophysical property differences.	Gas_production_permitting	Mine permitting not best model for gas permitting
004	The Band encourages the State not to proceed with its current plans for a temporary regulatory framework. We encourage the State to continue with its moratorium on all gas extraction development until a robust and final regulatory framework has been developed, received public comment, and been duly approved in accordance with state law. Statements from GTAC or its officials suggesting that gas extraction will occur regardless of whether there is a regulatory framework shirks the State's duty to ensure compliance with environmental laws and undermines the State's regulatory powers to develop a protective and thoughtful regulatory framework for this type of extraction. We remind the State that it has the authority to continue to halt gas extractive activities, until a robust regulatory framework has been developed that will protect the health of the people, the quality of air, land, and waters, and the other natural resources dependent upon them. We encourage the DNR and GTAC to work together with the Tribes to develop a robust final regulatory framework through meaningful Tribal Consultation as established in Minnesota Statutes Section 10.65.	Process	There should be no temporary framework
005	The Band encourages the State not to proceed with its current plans for a temporary regulatory framework. We encourage the State to continue with its moratorium on all gas extraction development until a robust and final regulatory framework has been developed, received public comment, and been duly approved in accordance with state law. Statements from GTAC or its officials suggesting that gas extraction will occur regardless of whether there is a regulatory framework shirks the State's duty to ensure compliance with environmental laws and undermines the State's regulatory powers to develop a protective and thoughtful regulatory framework for this type of extraction. We remind the State that it has the authority to continue to halt gas extractive activities, until a robust regulatory framework has been developed that will protect the health of the people, the quality of air, land, and waters, and the other natural resources dependent upon them. We encourage the DNR and GTAC to work together with the Tribes to develop a robust final regulatory framework through meaningful Tribal Consultation as established in Minnesota Statutes Section 10.65.	Tribal_relations	Need for consultation
008	Tribal nations are sovereign, not stakeholders. The Band retains hunting, fishing, and other usufructuary rights that extend throughout the entire northeastern portion of the state of Minnesota under the 1854 Treaty of LaPointe1, and through central Minnesota into Wisconsin under the Treaty of St. Peters, 1837 (lands ceded to the federal government). These rights have been reaffirmed by federal courts, including the US Supreme Court2. Throughout these ceded territories, all signatory Bands have a legal interest in protecting natural resources, and in the state of Minnesota, all state agencies are under Executive Order and statutory requirements to engage in timely and meaningful government to government consultation3. The proposed helium gas extraction project, Pulsar Helium's "Topaz" project, which predicated this Legislature-directed expedited regulatory framework and preliminary statutory process, lies within the 1854 Ceded Territory and upstream of the Fond du Lac Reservation.	Tribal_relations	Usufructuary rights
009	Over several decades of coordinated resource monitoring, management, and engagement with state and federal regulatory agencies in the review of industrial and extractive projects posing significant adverse environmental impacts and risks to natural and cultural resources, the Band's clear and consistent position has been to ensure these resources remain healthy, sustainable, and accessible for future generations. We have substantial concerns about a new (to this state) extractive industry and the unknown risks that its construction and operation poses, and the demand on state regulatory agencies to scramble to allow a project like this to be permitted for operations before environmental and human health hazards are fully understood, and a robust statutory process established. This urgency on the part of the Legislature neither respects tribal standing, nor ensures the public interest is upheld. The claim that the company could start commercial exploration within 12-18 months should not be the primary driver for unduly rushing the creation of a framework for responsible state agency review and regulatory oversight.	Process	Permits before full understanding
010	DNR-5, regarding a gas resource development permit and the areas that are disturbed (gas resource development locations), acknowledges that a project "footprint" extends beyond the immediate vicinity of a drilled well. This is a critical factor for environmental review and permitting, as project impacts include needed infrastructure development (roads, pipelines, compressor stations), nonpoint source impacts (erosion, sedimentation), increased traffic, noise, air emissions and more. Permitting a gas resource like helium has the potential for substantially more impacts than exploration borings for minerals and should be managed from the beginning as such.	Environmental_review	Environmental impacts
011	DNR-7, regarding application and permit fees. The DNR acknowledges that the $50,000 application fee paid by nonferrous mining permittees "has been dwarfed by order of magnitude by the legal fees paid by the DNR to defend the related permit decision in court." Fond du Lac and other tribal agencies have also expended substantial resources in staff environmental and permit review, and outside technical support and legal counsel to defend our right to access sustainable treaty resources imperiled by proposed extractive projects permitted by the DNR. We recommend that project proposers provide affected tribes with the same $75,000 fee for gas resource development projects that is provided to the DNR. This reflects the amount of staff time required to review and provide substantive input to permits for projects that may affect treaty and reservation resources.	Gas_production_permitting	Permit fees duplicated to Tribes
012	DNR-8: Gas resource development permits issued under a temporary regulatory framework must be considered temporary, expiring once ruled for a permanent regulatory framework are promulgated. Although the MN Legislature has directed state agencies to rush this framework on behalf of Pulsar, the company itself has stated they haven't yet finished their exploratory phase and won't have a defined project ready for review and permitting for at least another 18 months (meeting between Pulsar and tribal leaders at the 1854 Treaty Authority 11/15/2024). Further, the DNR maintains: "The risks that a permanent regulatory framework for gas resource development would be dramatically different than a temporary framework might be a strong disincentive to invest in a project if the permittee was forced to reapply for a new "permanent" permit once rules were promulgated." This rationale is disingenuous at best; any company proposing a new gas project in a state without an existing regulatory framework must be willing to risk their need to update a temporary permit issued prior to final rulemaking. Deferring to one company's desire to accelerate their project without adherence to final state rules would provide an improper advantage to that specific company.	Gas_production_permitting	Temporary permits

013	DNR-9, regarding siting and setbacks for gas resource development projects. The Band maintains that setbacks or separations that have been deemed appropriate fornonferrous mineral development projects may not in fact be appropriate for a gasresource development project. And the DNR assumption that gas projects are not likely to present higher risks that nonferrous mineral projects is simply not supported; unless and until a comprehensive environmental impact statement (EIS) is completed for a gas resource development project, the agency cannot assume a particular level of risk. For example, the risk of release of radioactive compounds must be fully considered and incorporated into risk assessment, monitoring and permitted controls. Helium is a radioactive decay product, and uranium is present in these geologic formations.	Environmental_review	Need for comprehensive EIS
014	The DNR has not even considered how to require Pulsar or any future gas resource development project to monitor for and control the release of radioactive gases, including radon. In fact, the only mention of radioactive products is found in the MPCA recommendations, regarding disposal of radium in solid waste.	Health_and_environmental_quality	Compliance monitoring
015	DNR-14, Financial Assurance. The DNR contends that, while there is not yet aframework for requiring financial assurance for a gas resource development project,there is an existing robust framework for mineral development project. Whileacknowledging that this 'robust framework' was established in the absence of activemining projects, it fails to note that this financial assurance framework is stilluntested. Financial assurance is an absolutely pivotal element for responsibleregulatory enforcement, including reclamation (including closure and post-closuremaintenance no matter when operations cease), corrective action for noncompliance,and ensuring natural resources can be restored or mitigated without taxpayer dollars.The fast-tracking of rulemaking for gas projects is also heedlessly short-circuiting thenecessary protections for tribal and public resources.	Financial_assurance	FA structure
016	DNR-22. In the absence of voluntary pooling (of mineral interests), the DNR wouldallow a person that owns or has secured the consent of the owners of at least fiftypercent of the mineral interests within a spacing unit to apply to the DNRCommissioner for a pooling order that would combine all of the mineral interestswithin a spacing unit for the development of gas resources within that unit. Therationale further speaks to the state having "a compelling interest to pool the interestsof both consenting and nonconsenting owners." If the state is going to forcenonconsenting owners to surrender their legal holdings (a 'taking'?), the processshould require at least 75% of the owners to consent to pooling within a spacing unit.Nonconsenting landowners may have other plans for their legal property that are notconducive to gas wells and extraction infrastructure.	Pooling_orders	% of owner consent
017	DNR-28. Unleased mineral interest tied to an American Indian tribe or band owning reservation lands in Minnesota or owned by the federal government should be shielded from pooling orders. While the Band agrees that tribal lands should be "shielded" from pooling orders, we ask that this term be clarified and that no pooling of gas/mineral rights should occur within the boundaries of reservation lands regardless of surface or subsurface ownership. This recommendation applies to both the temporary and permanent regulatory frameworks.	Pooling_orders	Shielding from pooling orders
018	The MDH acknowledges that existing state well drilling regulations apply to exploratory boring or prospecting, and do not anticipate that those same borings would likely also be used for gas production. In addition to the recommended statutory changes (MDH-1, MDH-2, MDH-3, MDH-6), we urgently recommend that MDH also explicitly acknowledge the risk of release of radioactive compounds and ensure regulatory control during drilling, production, and sealing of gas wells.	Environmental_review	Radioactive materials
019	MDH-7, MDH-8 prohibits injection or disposal of liquid, gas, or chemicals in gas wells, and acknowledges the US Environmental Protection Agency's federal permitting authority for Class 2 injection wells. The GTAC should be transparent with the public and the Legislature in that the USEPA is not bound by state directives to accelerate environmental review and permitting of a gas resource development project. Additionally, a gas resource development project should not move forward, under either temporary or permanent state permitting, unless and until it has secured all necessary permits, including a federal Class 2 injection well permit.	Gas_production_permitting	Need for all required permits
020	Despite a concerted effort in recent years on the part of the EQB to improve tribal consultation and coordination around environmental review and decision-making, nowhere in their recommendations for gas resource development do they incorporate tribal consultation or ensure opportunities meaningful tribal input. Yet tribal communities and treaty-protected resources are at significant and disproportionate risk for degradation from yet another resource-extractive industry.	Tribal_relations	Need for consultation
021	EQB-1, establishing a new mandatory category for environmental review and designating the DNR as the responsible governmental unit (RGU). While we agree that this new type of industrial development should be subject to a new mandatory environmental review category, we strongly advocate for the EQB to require a full environmental impact statement (EIS). This is the appropriate approach for an industry that does have the potential for significant environmental effects, alongside the state's complete lack of experience in regulating, mitigating and enforcing compliance on gas development projects. An EIS has more requirements for analyses and alternatives, mitigation of adverse environmental and human health effects (including the toxic and carcinogenic effects from radioactive compounds or elements), cumulative impacts, environmental justice, greater public involvement, and tribal consultation.	Environmental_review	Need for comprehensive EIS
022	The draft recommendations state that mandatory category thresholds are triggered by the project size or "footprint," without defining those size thresholds. In fact, EQB is apparently suggesting that allowing the Pulsar project to proceed under temporary permitting and a less robust or comprehensive EAW will enable them to define that threshold in the future. This approach is simply not consistent with state or federal environmental policy, nor is it protective of the public interest. Pulsar has stated its direct footprint will be five times the size that DNR has estimated for gas well projects (10 acres). And this preliminary project footprint estimate is provided by a company that currently holds over 4,000 acres of surface rights surrounding its currently active drilling sites. The overall scale of this project could significantly increase, and an EIS is the appropriate mandatory environmental review instrument.	Environmental_review	Need to define mandatory category thresholds
023	Finally, the Band does not agree with the recommendation for the DNR to be the "natural fit" as RGU for mandatory environmental review. The DNR is responsible for pooling, spacing, siting, financial assurance and reclamation for state-leased mineral rights; in the case of private mineral rights on private or federal lands, the DNR's sole responsibility is to ensure the project does not extract resources they do not own or lease, and that closure/reclamation plans are followed. The MPCA has responsibility for significantly more regulatory oversight, including water quality permits, wastewater permits, industrial stormwater permits, construction stormwater permits, air quality permits, storage tank regulation and permitting, and potentially for solid waste permitting. The Band recommends that MPCA be designated the RGU for mandatory environmental review of gas resource development projects.	Environmental_review	MPCA should be RGU
024	MPCA was the only agency to specifically acknowledge the need for tribal consultation in their regulatory role.	Tribal_relations	Need for consultation
025	The MPCA also called attention to significant uncertainties about air permitting requirements and management of greenhouse gas emissions, as well as industrial solid waste management. These uncertainties would be more adequately addressed and clarified through an EIS process.	Environmental_review	Need for comprehensive EIS
026	DOR-1, DOR-2, DOR-3: The Minnesota Department of Revenue is recommending that gas extraction be taxed in the same way that non-ferrous mineral mining is taxed, through a Gross Proceeds or severance tax, and an Occupation or income tax (applicable to all mining). They have not apparently conducted any type of economic analysis to determine what are likely significant differences in revenue streams vs. production expenses to demonstrate that in fact this vastly different type of resource extractive industry should be assessed in exactly the same way and at the same rate as non-ferrous mining. That analysis should be conducted to ensure the public is fairly compensated for private company profit.	Revenue_generation	Need for economic analysis

027	Finally, a percentage of the Gross Proceeds Tax and Occupation Tax should be allocated to each tribe with reserved rights in the ceded territory where the resource is being extracted, to nominally compensate for the diminishment of irreplaceable natural resources. The Band looks forward to further opportunities to review the emerging regulatory framework, and to engage in consultation with the state agencies on this new type of industrial development.	Tax_distribution	Tax proceeds to Tribes
028	The Grand Portage Band of lake superior Chippewa (the "Band") hereby submits these comments in connection with the Gas Technical Advisory Committee draft rules for gas extraction provided to Tribes at 4:10 pm on November 15, 2024, with our comments due by close of business on November 25th, 2024. This timeframe is far too short, and we criticize all the GTAC agencies for not consulting with all Tribes whose nations are within the State of MN boundaries as the rules were drafted. This appears to be purposeful and does not allow adequate time to respond before the draft rules are provided to the public for comment. This violates MN Executive Order 13175 - Consultation and Coordination With Indian Tribal Governments (Nov. 6, 2000) stating "the United States has recognized Indian tribes as domestic dependent nations under its protection,"there is a "trust relationship with Indian tribes," and "[a]gencies shall respect Indian tribal self-government and sovereignty, honor tribal treaty and other rights, and strive to meet the responsibilities that arise from the unique legal relationship between the Federal Government and Indian Tribal Governments.").	Tribal_relations	Need for consultation
029	Grand Portage is a federally recognized Tribe that has retained hunting, fishing, and other usufructuary rights in the lands and waters that extend throughout the entire northeast portion of the state of Minnesota under the 1854 Treaty of LaPointe1 (the "Ceded Territory"). Usufructuary rights were retained to ensure hunting, fishing, and gathering for subsistence, economic, cultural, medicinal, and spiritual needs could continue into perpetuity. "Reserved property rights, explained by the Supreme Court in 1905 in United States v. Winans, 198 U.S. 371, are not 'a grant of rights to the Indians, but a grant of rights from them In Winte v. United States, 207 U.S. 564 {1908), the Supreme Court applied this principle in a water rights case. These two cases ore the basis of the "reserved rights doctrine", that recognizes tribes retain those rights of a sovereign government not expressly extinguished by a federal treaty or statute."2 In order to fully exercise these guaranteed treaty rights, abundant unpolluted natural resources must be available.	Tribal_relations	Usufructuary rights
030	Because of their unique government-to-government relationship with the Minnesota tribes, state3 and federal agencies• are legally responsible for maintaining treaty-reserved natural resources. All state agencies are required to consider the input gathered from tribal consultation in their decision-making processes, with the goal of achieving mutually beneficial solutions,5 yet this has not occurred with respect to the draft rules for gas extraction. Due to constraints by the GTAC for review of the draft rules, these comments should not be considered exhaustive.	Tribal_relations	Need for consultation
031	The risk of release and the concentrations of radioactive components must be discussed and rules developed to ensure radioactive waste is captured and disposed of safely. Helium is created by the natural radioactive decay of radioactive elements, primarily uranium and thorium. Yet, there is little discussion regarding radioactive releases that are likely to occur with gas extraction and in particular, helium extraction. In fact, the only mention of this potential In the draft rule includes: "No solid waste permits would be required. This is not an Industrial activity that treats, transfers, stores, processes, or disposes of solid waste. However, a guidance document on water filter backwash solids has criteria for the disposal level criteria for radium. Should there be a need to dispose of solid waste that has radium contained in, the acceptable radium disposal limit is in guidance only. Moving forward, the MPCA could consider adding a rule disposal restriction related to radium levels for any waste generated from the gas industry in the section that lists the industrial waste types that must be addressed in the Industrial Solid Waste Management Plans." (GTAC draft rules) There must be rules for any radioactive waste or discharges to the air or water that may occur as a result from extracting gas that was created by radioactive decay, in an area where the known concentrations of radon already approach unhealthy or dangerous concentrations. Because radon usually shows up later in the extraction processes, it's much harder to manage than other pollutants.	Environmental_review	Radioactive materials
032	The idea that no solid waste permits will be needed for future gas projects assumes that all the industrial equipment needed to separate, process, store, and transfer gas to market will be maintained off-site. Each gas or oil extraction project will likely be different so unless there is more information that has not been provided in these draft rules, there should be an assumption that all gas and oil extraction projects will need Industrial Solid Waste Management Plans that include safe capture, storage, and disposal of all radioactive waste generated.	Health_and_environmental_quality	Need for solid waste permit
033	Suggesting that "'(W]here recovery and use of the methane is not feasible, converting the methane to CO2 through flaring may be the next best option. Flaring, sometimes used in managing landfill gases, would also provide the benefit of reducing or eliminating non-methane hydrocarbons, air toxics, and odor causing compounds that may be found at lower concentrations in the well gas and that would otherwise be released to the atmosphere...»(GTAC draft rules) Flaring will not eliminate radioactive components (e.g. radon gas or radium nitride).	Health_and_environmental_quality	Flaring
034	An Environmental Impact Statement (EIS) has more requirements than an Environmental Assessment (EA) to explore methods to reduce adverse environmental and human health effects, including cumulative effects, requires more public evaluation and consultation with Tribal leaders, and includes reviews by Tribal Historic Preservation Officers. The draft suggests that mandatory category thresholds are based on project size, with EAW thresholds associated with projects of a smaller size while an EIS is triggered by a larger project. However, those size thresholds are not disclosed in this draft. The draft suggests that most gas wells cover about a ten-acre footprint. In consultation with Pulsar, the company has stated its direct footprint will be 5 times the size the MNDNR has suggested for gas well projects, or about 50 acres. This is a preliminary estimate from a company that currently holds more than 4,181 acres of surface rights for its project, so the footprint and overall scale of the project could significantly increase.	Environmental_review	Need to define mandatory category thresholds
035	An Environmental Impact Statement (EIS) must be required for all gas projects because of the potential for significant environmental effects, including the release of radium isotopes, all of which are radioactive, including radon, and are considered toxic, and carcinogenic due to radioactivity. 226Ra is the most stable isotope of radium and is the last isotope in the (4n + 2) decay chain of uranium-238 with a half-life of 1,600 years, making up almost all naturally occurring radium. The immediate decay product of radium is radon. Radon is 2.7 million times more radioactive than the same molar amount of natural uranium (mostly uranium-238), due to its proportionally shorter half-life. Radium can also form a solid phase, radium nitride (Ra3N2), when it is exposed to air because it reacts with nitrogen rather than oxygen to form a black surface layer.	Environmental_review	Radioactive materials
036	Ethane will be released by the project, potentially flared off as it converts to methane upon exposure to the atmosphere. Methane is a potent greenhouse gas that must be captured. At or above 5 percent ethane or methane, a gas mixture can become explosive. It appears that Pulsar may have concentrations of ethane and/or methane at or near 5 percent (GTAC draft rules), creating the potential for explosion or fire that must be thoroughly investigated.	Health_and_environmental_quality	Flaring

037	A frequent occurrence resulting from gas extraction is very saline water being pushed to the surface. This can have disastrous Impacts on local vegetation and aquatic life that have evolved in conditions with very low concentrations of salts. Very saline water from 1,371feet below the surface was contacted causing the unauthorized discharge of 330,000 gallons of to the surrounding surface environment during the AMAX copper-nickel exploration in 1976 (MPCA memo AMAX Exploration Unauthorized Discharge, 9/2/1976) killing over an acre of vegetation surrounding the drill site. At every copper/nickel test drill site where samples were collected, the US Forest Service found saline waters that exceeded the safe drinking water criteria of 250 milligrams per liter of chloride (USFS. Marty Rye. 2012). There may be metals at concentrations that exceed human health in the saline water including, but not limited to barium, strontium, and arsenic.	Health_and_environmental_quality	Saline water
038	An EIS is needed to assess the potential need for deep injection wells or other pollution control methods that may be required to protect human health and the environment. Both the EA and EIS costs should be borne by the applicant and an EIS must be mandated for every proposed gas project.	Environmental_review	Need for comprehensive EIS
039	An EIS is needed to assess the potential need for deep injection wells or other pollution control methods that may be required to protect human health and the environment. Both the EA and EIS costs should be borne by the applicant and an EIS must be mandated for every proposed gas project.	Environmental_review	EAW and EIS costs
040	"There are commonly two types of taxes collected on mining in Minnesota and nationally: A severance tax for removing the natural resource from the earth and an income tax. In Minnesota, the severance tax for non-ferrous minerals is known as the Gross Proceeds Tax and the income tax for all mining is known as the Occupation Tax. The scope of recommendations on taxation includes incorporating gas and oil into existing mining tax laws, aligning the exemptions for the newly created gas and oil taxes with exemptions in place for existing mining industries1 and improving tax administration for both the taxpayer and Revenue. Rulemaking Is not included in the scope of these recommendations. Rulemaking is not specifically included in the scope of these recommendations because the Department believes the draft statutory language is sufficient on its own. The Department already has rule making authority under Minnesota Statutes, section 270C.061 should it be determined rules are needed later." (GTAC draft rules) A portion of Gross Proceeds and Occupation taxes collected for natural resource extraction should be granted to each Tribe with reserved rights in the ceded territory where the resource is extracted to compensate for the loss of irreplaceable natural resources.	Tax_distribution	Tax proceeds to Tribes
041	The DNR has recommended a $50,000 application fee for a gas resource development permit and a $75,000 annual permit fee for gas resource development projects, as well as the ability to assess supplemental fees to cover the costs of reviewing an application above the application fee amount. (GTAC draft rules) We recommend fees for Tribes of an equal amount for review and regulatory oversight within our ceded territories.	Gas_production_permitting	Permit fees duplicated to Tribes
042	Gas resource development permits issued under a temporary regulatory framework must be considered temporary, expiring once rules for a permanent regulatory framework are promulgated. "The DNR recommends that the word "temporary" be removed from the phrase "temporary permit," to make clear that a permit issued during rulemaking will not be limited to a term less than what is proposed by the applicant, nor revoked once rules are promulgated." (GTAC draft rules) This Is an unnecessary "gift" to Pulsar. Although this rulemaking is being rushed for Pulsar, the company has stated they haven't finished the exploration stage yet, and don't anticipate having a "project" defined for at least another 18 months (Meeting held at the 1854 Treaty Authority 11/15/2024). We strongly disagree with the MNDNR's rationale because it potentially allows Pulsar to operate with advantage over any future companies exploring for helium in MN and allow unmitigated pollution to occur that could adversely impact human and environmental health despite the final rules being adopted. The draft further provides: "The risks that a permanent regulatory framework for gas resource development would be dramatically different than a temporary framework might be a strong disincentive to invest in a project if the permittee was forced to reapply for a new "permanent• permit once rules were promulgated." (GTAC draft rules) This is false rhetoric. At a million dollars per day of expected revenue once operating, there is no disincentive to wait for the final rulemaking other than wanting lax temporary rules that may not be as restrictive as the final rules. "The initial land package Is being expanded through applications with the State Government meaning that all areas of Interest have now been quarantined by Pulsar for further development. Importantly, the State of Minnesota passed new helium legislation allowing production to occur from 15 January 2025." (Pulsar Helium Inc. - Projects - Topaz). Any company proposing a new gas extraction project in MN must be willing to risk an update to the permit as soon as final rulemaking has occurred, not at some undetermined later date, or possibly never. Pulsar knows it is taking a risk by developing plans before rulemaking has been completed and should expect to be able to operate under a temporary permit only until the rules are finalized, complying with the legislature's desire for a viable mechanism to enable gas resource development project permitting during rulemaking without providing an improper advantage to a specific company.	Gas_production_permitting	Temporary permits
043	The DNR recommends that a person applying for a pooling order control at least fifty-percent of the mineral interests within an established spacing unit. We do not think fifty percent ownership of mineral interests is enough for a pooling order. We recommend a minimum of a 75 percent interest requirement for pooling. The MNDNR recommends that the operator of wells under a pooling order in which there is a nonconsenting owner furnish the nonconsenting owner with a monthly statement of all costs incurred, together with the quantity of gas produced, and the amount of proceeds realized from the sale of production during the preceding month. This Is a good recommendation, but only if the pooling order is provided when there is at least 75 percent ownership of the mineral estate. 50 percent is an unfair advantage to the right holder that wants to develop gas if their neighbor has other plans that may not be conducive to gas wells.	Pooling_orders	% of owner consent
044	"Until more information is available about the nature and extent of Minnesota's gas resources, the DNR recommends that gas resource development permittees submit to the commissioner, as a permit condition a pre-production report that includes the engineering and geological data obtained from any gas wells drilled as part of their project (whether or not the permittee plans to take a gas well into production). The report must compare the hard data obtained from their gas wells against any estimates submitted to the commission before drilling. The commissioner will use the data to evaluate potential changes to an established spacing unit or pool unit and consider the potential impacts of bringing the project into production." (GTAC draft rules) This information must be simultaneously provided to the tribes.	Data_sharing_public_data	Pre-production report should go to Tribes
045	Although the DNR recommends that unleased mineral Interests tied to an American Indian tribe or band owning reservation lands In Minnesota should be shielded by state law from state-issued pooling orders, we believe that pooling should be prohibited within any Tribe's reservation boundaries regardless of surface or subsurface ownership. This recommendation is for both the temporary and post-rulemaking regulatory frameworks.	Pooling_orders	Shielding from pooling orders
046	"Legislation passed in May 2024 requires the commissioner to develop rules for siting gas resource development projects (93.514). Gas resource development locations need to be at sites that minimize adverse impacts on natural resources and the public, with setbacks or separations that are needed to comply with environmental standards, local land use regulations, and requirements of other appropriate authorities." Siting could be a huge issue that may collide with the wants and needs of non-ferrous mining proposals moving forward. Siting should be assessed in an EIS.	Environmental_review	Alternative site analysis

047	"The final component of a framework for environmental review is determining who should serve as the Responsible Governmental Unit. EQB recommends that the Department of Natural Resources serve as the Responsible Governmental Unit." We do not agree that the MNDNR is the natural fit for serving as the RGU because they do not have the greatest responsibility for supervising or approving the project as a whole. Instead, we recommend that MPCA become the RGU for gas extraction projects because they are the agency tasked with the most regulatory oversight including: wastewater permits, industrial stormwater permits, construction stormwater permits, air quality permits, storage tank regulation and permitting, and solid waste permitting. Along with MDH, MPCAs authorities are tied to protecting human health and the environment. When the state is leasing mineral rights MNDNR has pooling, spacing, siting, financial assurance, and reclamation for the extraction of gas. In the case of private minerals on private or federal lands, the MNDNR Is only assigned to ensure that the projects do not extract resources they do not own or lease, and that closure plans that protect and maintain the surface are followed. In either case, state-leased or privately held minerals, MPCA has more regulatory authorities than the MNONR, and therefore should be considered the RGU.	Environmental_review	MPCA should be RGU
048	We agree that corporate guarantees are worth no more than the paper they are written on, and the State must have much more robust tools for financial assurance for gas projects. Financial assurances are a source of funds to be used if the permittee fails to perform: • Reclamation activities including closure and post closure maintenance needed if operations cease; and • Corrective action as required by the MPCA and the MNDNR if noncompliance with engineering design and operating criteria occurs; and • *To ensure that other natural resources are not damaged or can be repaired or mitigated using financial assurance instead of taxpayer revenue.* (Here, italicized font is suggested additional text provided by Grand Portage)	Financial_assurance	FA structure
049	The MNDNR should not allow money collected as part of financial assurance for gas resource development projects to be invested by the State Board of Investment unless there is a requirement to supplement any funds that are diminished by investment to their original amount. If investment yields generate more money that is helpful. However, if the investments decrease the amount of financial assurance a company has provided, there may not be enough funds to deal with the work that is needed. Therefore, interest bearing accounts must be very conservative in nature to ensure no loss of funds.	Financial_assurance	SBI investment of FA
052	The current document recommends that a forced/involuntary pooling order may be issued if the ownerships of at least 50% of the mineral interests in a spacing unit requests an order from the DNR. This is entirely unacceptable and forced pooling should not be allowed unless a minimum of 75% of mineral interests request it, as is the practice in other states. Although this document suggests nonconsenting owners be provided proportionate and equitable compensation, additional compensation should be provided to nonconsenting owners.	Pooling_orders	% of owner consent
053	The extent of helium or other gas resources in Minnesota is not currently known, and helium is a critical finite resource with global demand. A reasonable owner of mineral interests may well determine they are better served by exercising their right to develop that interest in the future. Additional compensation should be provided to nonconsenting owners in a forced pool to recompense those owners' lost opportunity cost. If additional compensation is not provided for, at a minimum, nonconsenting owners should not be assessed a "risk penalty" or other costs of infrastructure development which they did not agree to.	Pooling_orders	Compensation for nonconsenting owners
054	Under federal law and as recommended in this document, unleased mineral interests tied to Tribes within their Reservations are shielded from forced pooling orders. Far too much has already been taken from Tribes by deception or force; this protection from forced pooling should also be extended to all mineral interests within Reservations and all mineral interests owned by Tribes within Ceded Territories.	Pooling_orders	Shielding from pooling orders
055	Recommendation MDH-6 requires notification to the Commissioners of Health, Natural Resources, and the Pollution Control Agency of events with the potential for significant adverse public health or environmental effects. This notification should also be provided to Tribes with rights or interests in the Ceded Territory or at the site.	Gas_wells	Notifications
056	Recommendation EQB-1 requires a mandatory EAW for any gas resource development project, with Department of Natural Resources as the Responsible Government Unit (RGU). This is absolutely inadequate, especially for the development of a temporary regulatory framework for an industry that has never before existed in the state. Because of the new nature of the industry to Minnesota, and the unexplored environmental risks such as radioactive materials related to gas production, an EIS is needed for all gas projects under the temporary framework and likely under permanent rules as well. The EQB has previously talked about the importance of equitable treatment and providing Tribes the opportunity to engage in projects and regulation. The only way to guarantee this equitable treatment and to allow Tribal participation is to require an EIS for all gas projects.	Environmental_review	Need for comprehensive EIS
057	The RGU for this project should be the Minnesota Pollution Control Agency, not the Department of Natural Resources. The majority of regulatory oversight for gas extraction would fall to MPCA in the form of water quality permits, stormwater permits (both construction and industrial), wastewater permits, air quality and solid waste permits, and storage tank regulations and permits. Under the draft rules, DNR would be responsible for pooling, spacing, siting, financial assurance, and site reclamation on leases of state mineral interests. On minerals privately held on private or federal land, DNR is only responsible for ensuring resources not owned/leased by the project are not extracted, and that protective closure plans are followed. In all cases, the MPCA has more regulatory authority for gas extraction projects than DNR, and should be the RGU.	Environmental_review	MPCA should be RGU
058	Methane and CO2 are likely to be large constituents of any gas development projects and a plan is needed for these gases. While Pulsar has discussed the capture of CO2 at the Topaz site, it may not be captured at other sites in the future. The direct venting of methane or CO2, or flaring of methane, at gas development projects is unacceptable. These are potent greenhouse gases which are currently securely stored within the existing geological formations. If a company intends to extract resources, then those resources need to be captured and put to beneficial use rather than destroyed or discharged to the atmosphere as a pollutant. In order to ensure that greenhouse gases are used, the rules governing development of gas resources should include a carbon fee of at least $200/ton of CO2-equivalent pollution, a rate which reflects the estimated social cost of carbon developed by the EPA in 2023 based on a 2% discount rate.	Health_and_environmental_quality	Flaring
059	Methane and CO2 are likely to be large constituents of any gas development projects and a plan is needed for these gases. While Pulsar has discussed the capture of CO2 at the Topaz site, it may not be captured at other sites in the future. The direct venting of methane or CO2, or flaring of methane, at gas development projects is unacceptable. These are potent greenhouse gases which are currently securely stored within the existing geological formations. If a company intends to extract resources, then those resources need to be captured and put to beneficial use rather than destroyed or discharged to the atmosphere as a pollutant. In order to ensure that greenhouse gases are used, the rules governing development of gas resources should include a carbon fee of at least $200/ton of CO2-equivalent pollution, a rate which reflects the estimated social cost of carbon developed by the EPA in 2023 based on a 2% discount rate.	Environmental_review	Carbon and climate change
060	The temporary and permanent rules need to discuss solid waste created by these projects. Helium is a product of the decay of radioactive elements such as uranium and thorium, and will likely occur with other decay products such as radium. There must be rules developed for potential radioactive waste and discharges of radioactive material to the air and water. Additionally, it is unknown what the extent of the eventual oil and gas industry in Minnesota will be, or what development of that industry may look like. It is short-sighted to not include solid waste management in the drafting of these rules.	Health_and_environmental_quality	Need for solid waste permit
061	The draft rules discuss the prohibition of hydraulic fracturing – fracking – for the future extraction of gas resources. We fully agree with this and support a complete ban on fracking for all gas and oil projects.	Health_and_environmental_quality	Hydraulic fracturing

062	Financial assurances for gas extraction projects are critical to ensuring that reclamation, mitigation, and corrective actions will be paid for in the event that a mining company is unable to for any reason. Money provided by projects for financial assurances should only be invested by the State Board of Investment if it is guaranteed by the State that any losses will be replaced to the original amount.	Financial_assurance	SBI investment of FA
063	When a violation occurs at gas extraction project, any fines and fees assessed as a result should be based on a percentage of the project's gross revenue rather than a fixed dollar amount. Fines for environmental violations should be substantial – possibly 10% of gross revenue per violation as that is comparable to some European Union regulations. If a company has the option of assessing the fixed potential cost of an environmental violation, it becomes a cost of doing business. By assessing fines as a percentage of gross revenue, violators would face true penalties for illegal actions and greater compliance rates should be expected.	Health_and_environmental_quality	Violation fines
064	In order to ensure equitability for Tribes, any application or annual operating permit fees paid to Minnesota should also be paid to Tribes in whose Ceded Territory a project is proposed or exists. A portion of Gross Proceeds and Occupation taxes collected from natural resource extraction projects should also be paid to Tribes with reserved rights in a Ceded Territory where projects occur. These funds would support the ability of Tribes to participate in the environmental review and regulation of these projects and compensate for the loss of natural resources and the opportunity to exercise treaty-protected rights.	Tax_distribution	Tax proceeds to Tribes
067	White Earth has concerns on the radioactive waste management. This is not addressed in the recommendations provided by GTAC. The potential release and concentration of radioactive components must be thoroughly addressed, with clear rules established to ensure the safe capture and disposal of radioactive waste. Helium, produced through the natural radioactive decay of elements such as uranium and thorium, raises concerns about radioactive releases during gas extraction-particularly helium extraction. However, the draft rules provide limited guidance on this issue, stating only: No solid waste permits would be required. This is not an industrial activity that treats, transfers, stores, processes, or disposes of solid waste. However, a guidance document on water filter backwash solids has criteria for the disposal level criteria for radium. Should there be a need to dispose of solid waste that has radium contained in it, the acceptable radium disposal limit is in guidance only. Moving forward, the MPCA could consider adding a rule disposal restriction related to radium levels for any waste generated from the gas industry in the section that lists the industrial waste types that must be addressed in the Industrial Solid Waste Management Plans.	Environmental_review	Radioactive materials
068	It is essential to establish regulations for managing any radioactive waste or discharges to air or water resulting from the extraction of gases formed by radioactive decay, particularly in regions where radon concentrations are already near hazardous levels. The presumption in the draft rules that solid waste permits will not be necessary assumes that all industrial equipment for processing, storing, and transferring gas will be located off-site. However, gas and oil extraction projects vary significantly. Without additional information provided in these draft rules, the default assumption should be that all such projects require Industrial Solid Waste Management Plans that detail the safe capture, storage, and disposal of radioactive waste.	Health_and_environmental_quality	Need for solid waste permit
069	Furthermore, the suggestion that "[w]here recovery and use of the methane is not feasible, converting the methane to CO2 through flaring may be the next best option," overlooks the persistence of radioactive components. While flaring may reduce non-methane hydrocarbons, air toxics, and odors, it does not eliminate radioactive substances such as radon gas or radium nitride.	Health_and_environmental_quality	Flaring
070	White Earth Nation recommends rulemaking on the issue of radioactive waste radioactive waste or discharges to air or water resulting from the extraction of gases formed by radioactive decay.	Environmental_review	Radioactive materials
071	An Environmental Impact Statement (EIS) should be mandated for all gas projects due to the potential for significant environmental effects, including the release of radioactive and toxic substances like radium isotopes, radon, and radium nitride. Radium-226, the most stable isotope of radium, is a key concern. It is the final isotope in the (4n + 2) decay chain of uranium-238, with a half-life of 1,600 years, and constitutes nearly all naturally occurring radium. Its immediate decay product, radon, is 2.7 million times more radioactive than the same molar amount of natural uranium due to its shorter half-life. Additionally, radium reacts with nitrogen in the air to form radium nitride (Ra3N2), a solid black compound, further demonstrating its hazardous nature. Unlike an Environmental Assessment (EA), an EIS has stricter requirements to assess methods for reducing environmental and human health risks, including cumulative effects. It also involves greater public scrutiny, consultation with Tribal leaders, and reviews by Tribal Historic Preservation Officers. The draft rules indicate that thresholds for requiring an EAW {Environmental Assessment Worksheet) or an EIS are based on project size, with smaller projects triggering an EAW and larger ones requiring an EIS. However, the specific size thresholds are not disclosed. According to the draft, gas wells typically have a ten-acre footprint. However, Pulsar, a company involved in these projects, has suggested its direct footprint will be five times larger, covering approximately SO acres. Pulsar currently holds surface rights to over 4,181 acres, indicating the potential for a significantly larger overall project scale.	Environmental_review	Need for comprehensive EIS
072	White Nation Nation recommends that both EA and EIS costs should be covered by the applicant, but given the scale and potential risks of gas projects, an EIS must be mandatory for all proposals to ensure thorough evaluation and mitigation of environmental and public health impacts.	Environmental_review	EAW and EIS costs
073	In Minnesota and nationally, two primary types of taxes are typically collected on mining: a severance tax, which applies to the removal of natural resources from the earth, and an income tax. In Minnesota, the severance tax on non-ferrous minerals is referred to as the Gross Proceeds Tax, while the income tax on mining is known as the Occupation Tax. Recommendations from the draft regarding taxation include: •Expanding existing mining tax laws to cover gas and oil extraction. •Aligning exemptions for new gas and oil taxes with those already established for the mining industry. •Enhancing tax administration to benefit both taxpayers and the Department of Revenue. Rulemaking is not explicitly included in these recommendations, as the Department believes the draft statutory language is sufficient. However, the Department retains rulemaking authority under Minnesota Statutes, section 270C.06, should future rules become necessary. White Earth Nation recommends a portion of the Severance and Occupation Taxes collected from natural resource extraction should be allocated to Tribes with reserved rights in the ceded territories where extraction occurs. This allocation would serve as compensation for the loss of irreplaceable natural resources within their ancestral lands.	Tax_distribution	Tax proceeds to Tribes
074	The DNR has recommended a $50,000 application fee for a gas resource development permit and a $75,000 annual permit fee for gas resource development projects, as well as the ability to assess supplemental fees to cover the costs of reviewing an application above the application fee amount. We recommend fees for Tribes of an equal amount for review and regulatory oversight within our ceded territories.	Gas_production_permitting	Permit fees duplicated to Tribes

075	Permits for gas resource development issued under a temporary regulatory framework must remain strictly temporary and should expire once permanent rules are established. The Minnesota Department of Natural Resources (MNONR) has proposed removing the term "temporary" from such permits, stating that this change would clarify that permits issued during the rulemaking process are not limited to shorter terms than requested by the applicant and would not be revoked once final rules are promulgated. However, this approach appears to favor Pulsar, a company that has admitted it is still in the exploration phase and does not expect to have a defined project for at least 18 months (per a meeting held at the 1854 Treaty Authority on 11/15/2024). This reasoning by MNDNR undermines the integrity of the rulemaking process, allowing Pulsar to potentially operate under less restrictive temporary rules, giving it an unfair advantage over future entrants in Minnesota's helium extraction industry. Draft rules also claim: The risks that a permanent regulatory framework for gas resource development would be dramatically different than a temporary framework might be a strong disincentive to invest in a project if the permittee was forced to reapply for a new 'permanent' permit once rules were promulgated. This argument is misleading. With anticipated revenues of $1 million per day once operational, there is no meaningful disincentive to waiting for final rules. The rush to secure permits under temporary, potentially less restrictive rules reflects a desire for regulatory leniency rather than genuine concern over investment risks. Furthermore, Pulsar has expanded its land package through applications with the State, as indicated in company statements: The initial land package is being expanded through applications with the State Government, meaning that all areas of interest have now been quarantined by Pulsar for further development. Importantly, the State of Minnesota passed new helium legislation allowing production to occur from 15 January 2025. It is essential that any company proposing gas extraction projects in Minnesota operate under the understanding that temporary permits will be subject to revision or expiration once final rulemaking is complete. Allowing indefinite use of temporary permits undermines the legislature's intent to establish a viable regulatory framework during the	Gas_production_permitting	Temporary permits
076	The DNR recommends that applicants for pooling orders control at least 50% of the mineral interests within an established spacing unit. However, we believe this threshold is insufficient. We recommend requiring a minimum of 75% ownership of the mineral interests for a pooling order to ensure fairness. The DNR also suggests that operators of wells under a pooling order, where there is a nonconsenting owner, provide the nonconsenting owner with a monthly statement detailing all costs incurred, the quantity of gas produced, and the proceeds from the sale of production during the prior month. While this is a reasonable recommendation, it should apply only when the pooling order is based on a minimum of 75% ownership. Allowing pooling with just 50% ownership unfairly favors developers over neighboring landowners who may have conflicting plans for their property that do not align with gas development.	Pooling_orders	% of owner consent
077	The MNDNR further recommends that, until more is known about Minnesota's gas resources, permittees for gas resource development should submit a pre-production report as a permit condition. This report would include engineering and geological data obtained from any drilled gas wells, whether or not they are taken into production. The report should compare actual data from the wells with any estimates submitted before drilling. This data would enable the commissioner to evaluate potential adjustments to established spacing or pool units and assess the impacts of bringing a project into production. Importantly, this information must also be shared simultaneously with the Tribes.	Data_sharing_public_data	Pre-production report should go to Tribes
078	Although the DNR recommends shielding unleased mineral interests tied to American Indian tribes or bands owning reservation lands in Minnesota from state-issued pooling orders, we believe that pooling should be entirely prohibited within any Tribal Reservation boundaries, regardless of surface or subsurface ownership. This prohibition should apply both during the temporary regulatory framework and after final rulemaking is complete.	Pooling_orders	Shielding from pooling orders
079	Legislation enacted in May 2024 requires the commissioner to establish rules for siting gas resource development projects (Section 93.514). These rules mandate that gas development sites be chosen to minimize adverse impacts on natural resources and the public, with setbacks and separations necessary to meet environmental standards, local land use regulations, and the requirements of other relevant authorities. Siting could become a significant point of contention, potentially conflicting with the priorities of proposed non- ferrous mining projects. Without a comprehensive Environmental Impact Statement {EIS) for gas extraction, it will be impossible to adequately evaluate whether gas development poses greater or lesser risks compared to non- ferrous mining.	Environmental_review	Alternative site analysis
080	The draft states, "The final component of an environmental review framework is determining the Responsible Governmental Unit (RGU). The Environmental Quality Board (EQB) recommends the Department of Natural Resources (MNDNR) serve as the RGU." We disagree with this recommendation, as the MNDNR does not have the primary responsibility for supervising or approving gas extraction projects in their entirety. Instead, we recommend that the Minnesota Pollution Control Agency (MPCA) serve as the RGU for gas extraction projects. The MPCA has the most extensive regulatory oversight responsibilities, including: • Water quality permits • Wastewater permits • Industrial and construction stormwater permits • Air quality permits • Storage tank regulation and permitting • Solid waste permitting These authorities, along with the Minnesota Department of Health (MOH), are directly tied to protecting human health and the environment. In contrast, the MNONR's role is more limited. Their responsibilities primarily include pooling, spacing, siting, financial assurance, and reclamation for gas and oil production when the state leases the mineral rights. For private minerals on private or federal lands, the MNDNR's oversight is restricted to ensuring that resources not owned or leased by the state are not extracted and that closure plans protect and maintain surface integrity. Given that the MPCA holds broader regulatory authority and is more directly involved in protecting environmental and human health, White Earth Nation believes MPCA is the most appropriate agency to serve as the RGU for gas extraction projects.	Environmental_review	MPCA should be RGU

081	We firmly believe that corporate guarantees are unreliable and insufficient for ensuring accountability in gas projects. White Earth Nation believe the State must adopt stronger financial assurance mechanisms to protect against potential failures by permittees. Financial assurances should provide a reliable source of funds for: •Reclamation activities, including closure and post-closure maintenance, in the event operations cease. •Corrective actions mandated by the MPCA and MNDNR due to noncompliance with engineering design and operating criteria. •Repairing or mitigating damage to other natural resources, ensuring that taxpayer funds are not used to cover these costs.	Financial_assurance	FA structure
082	The White Earth Nation requests that MNDNR should prohibit funds collected for financial assurance in gas resource development projects from being invested by the State Board of Investment unless there is a guaranteed requirement to replenish any losses to maintain the original fund amount. While investment yields could increase available funds, any reduction due to investment losses could leave insufficient resources to address necessary reclamation or corrective actions. To safeguard these funds, interest-bearing accounts must be managed conservatively to ensure zero loss of principal, prioritizing the availability of funds over potential investment gains.	Financial_assurance	SBI investment of FA
084	The Band realizes the terminology used by the State and the Band differ greatly due to differing relationships to the land, but at the core we hope that we have common vision for our shared future. The Band agrees that the newly proposed or amended State statutes and rules, regardless of whether the rulemaking process is standard or expedited, must to establish protections for the health of the air, land, and aquatic environments, and for the health of the people, our relatives in nature, and our economy when extracting these gas resources and gifts of the Earth. Newly proposed or amended statutes and rules developed under the current expedited rulemaking process should establish procedures for exploring and accessing the state's gas resources. These rules should also be developed with future amendments in mind, should liquid hydrocarbon and/or non-hydrocarbon resources be discovered, or if there are future efforts toward liquids exploration in the State. The Band agrees that Chapter 93 of the Minnesota Statutes is the appropriate place to incorporate these changes.	Process	Robust regulation
085	The Band agrees with this recommendation, given MDH's existing authority related to the sealing of aquatic wells and exploratory boreholes. The DNR's recommendation is a logical and consistent application of current Minnesota Statute 103I.301.	Gas_wells	Exploratory borings
086	Regarding the Recommendation DNR-3: The Band agrees with the general premise of the DNR's recommendation to use existing statutes and rules for permitting mine projects in Minnesota as a model for establishing comparable permitting requirements and policies for gas resource development projects, however, the Band does not agree with the specific recommendations here. For instance, the Band does not agree that the State should use existing Minnesota statutes and rules related to the evaluation and permitting of mining projects as a model for establishing comparable permitting requirements and policies for gas resource development projects. There are significant geologic distinctions between the fluidity of gas and the solid ore resources, which make mining a poor corollary for natural gas permitting. The Band believes that the better model is the permitting structure for groundwater, another fluid resource.	Gas_production_permitting	Mine permitting not best model for gas permitting
087	Regarding the Recommendation DNR-4: The Band agrees with the DNR's recommendation that permits for gas resource development projects should be required before gas wells are drilled. However, the currently proposed statutory language for Minnesota Statute 93.5174 offers no procedure for the inadvertent discovery of gas resources during mineral exploration, or for transferring permits from mineral resources to gas resources. The Band encourages GTAC to consider procedures related to inadvertent discovery of natural gas.	Gas_production_permitting	When is a permit needed
088	Regarding the Recommendation DNR-5: The Band agrees with the DNR's recommendation that permits for gas resource development projects should apply to "gas resource development locations," where gas development operations disturb the ground surface. the Band also agrees that these "gas resource development locations," should be treated as distinct from spacing units or extraction areas that are the undisturbed surface expression of subsurface gas extraction.	Spacing_unit	General
089	Regarding the Recommendation DNR-6, the Band agrees that the extraction of gas resources should be limited to gas wells at permitted gas resource development locations. The Band believes that the extraction of gas resources from exploratory borings that are located outside of permitted gas resource development locations should be prohibited by statute.	Gas_wells	Exploratory borings
090	Regarding the Recommendation DNR-7, the Band agrees that the application fee and annual development fee for gas resource development projects should mirror comparable fees for nonferrous mine projects. The Band further agrees that the commissioner for the Responsible Government Unit must not issue the gas resource development permit until the applicant has paid all fees in full.	Gas_production_permitting	Permit fee transparency
091	Recommendation DNR-8 incorporates two sub-recommendations: (a) gas resource development permits issued during rulemaking and the temporary regulatory framework should remain valid after the completion of rulemaking; and (b) if gas resource projects permitted during the temporary framework require permit amendments or substantive changes after rulemaking, the permit should be updated to reflect the permanent regulatory framework. As to each sub-part of Recommendation DNR-8, the Band reminds the DNR that State regulatory agencies have the power to decline to issue permits, and maintain a moratorium on any gas resource development until there has been proper, substantive, and meaningful consultation with the Tribes. The Band's position is that the state must first conduct consultation under Minnesota Statute section 10.65, and can then craft a robust and comprehensive regulatory framework for gas development. State regulatory agencies should begin to review applications and issue permits only after the State has implemented a comprehensive regulatory framework for gas development.	Process	Robust regulation
092	Recommendation DNR-8 incorporates two sub-recommendations: (a) gas resource development permits issued during rulemaking and the temporary regulatory framework should remain valid after the completion of rulemaking; and (b) if gas resource projects permitted during the temporary framework require permit amendments or substantive changes after rulemaking, the permit should be updated to reflect the permanent regulatory framework. As to each sub-part of Recommendation DNR-8, the Band reminds the DNR that State regulatory agencies have the power to decline to issue permits, and maintain a moratorium on any gas resource development until there has been proper, substantive, and meaningful consultation with the Tribes. The Band's position is that the state must first conduct consultation under Minnesota Statute section 10.65, and can then craft a robust and comprehensive regulatory framework for gas development. State regulatory agencies should begin to review applications and issue permits only after the State has implemented a comprehensive regulatory framework for gas development.	Process	Permits before full understanding
093	Recommendation DNR-8 incorporates two sub-recommendations: (a) gas resource development permits issued during rulemaking and the temporary regulatory framework should remain valid after the completion of rulemaking; and (b) if gas resource projects permitted during the temporary framework require permit amendments or substantive changes after rulemaking, the permit should be updated to reflect the permanent regulatory framework. As to each sub-part of Recommendation DNR-8, the Band reminds the DNR that State regulatory agencies have the power to decline to issue permits, and maintain a moratorium on any gas resource development until there has been proper, substantive, and meaningful consultation with the Tribes. The Band's position is that the state must first conduct consultation under Minnesota Statute section 10.65, and can then craft a robust and comprehensive regulatory framework for gas development. State regulatory agencies should begin to review applications and issue permits only after the State has implemented a comprehensive regulatory framework for gas development.	Tribal_relations	Need for consultation

095	Regarding the Recommendation DNR-9a: although the Band agrees that the setbacks contemplated here should not be less-than those proposed for nonferrous mining projects for different classes of lands around the proposed site. However, some gasses are heavier than air, and have the potential to asphyxiate personnel in the vicinity without proper personal protection equipment. Accordingly, the Band recommends that a person must not place, construct, or install a gas well less than 1,600 feet from a residential building; 1,600 feet from a water supply well; or 3,200 feet from a school facility or a care facility, such as childcare centers, nursing homes, hospitals, and clinics.	Health_and_environmental_quality	Worker safety
096	Regarding the Recommendation DNR-9a: although the Band agrees that the setbacks contemplated here should not be less-than those proposed for nonferrous mining projects for different classes of lands around the proposed site. However, some gasses are heavier than air, and have the potential to asphyxiate personnel in the vicinity without proper personal protection equipment. Accordingly, the Band recommends that a person must not place, construct, or install a gas well less than 1,600 feet from a residential building; 1,600 feet from a water supply well; or 3,200 feet from a school facility or a care facility, such as childcare centers, nursing homes, hospitals, and clinics.	Environmental_review	Siting and setbacks
097	Regarding the Recommendation DNR-9b, the Band reiterates the caution it expressed with regard to Recommendation-DNR 8, and urges the DNR to engage in consultation pursuant to Minnesota Statute 10.65, prior to developing the permanent regulatory framework for gas development. Once the comprehensive regulatory framework for gas development has been implemented, then the State's regulatory agency may begin issuing permits after review of the permit application, with the proper setbacks promulgated with siting rules for gas resource development projects.	Tribal_relations	Need for consultation
098	Regarding the Recommendation DNR-9b, the Band reiterates the caution it expressed with regard to Recommendation-DNR 8, and urges the DNR to engage in consultation pursuant to Minnesota Statute 10.65, prior to developing the permanent regulatory framework for gas development. Once the comprehensive regulatory framework for gas development has been implemented, then the State's regulatory agency may begin issuing permits after review of the permit application, with the proper setbacks promulgated with siting rules for gas resource development projects.	Process	Permits before full understanding
099	Additionally, please note that though the recommendation cites Minnesota Statute 93.5174, subd. 8, the draft regulations at Section 14 have no such subdivision. There is a Section 15 for Temporary regulatory framework with items (1) through (6), but this is not explicitly marked as Minnesota Statute 93.5174, subd. 8.	Process	Statutory language
100	Recommendation DNR-10 includes two sub-recommendations: (a) a temporary regulatory framework for permitting gas development projects should include annual reporting requirements that are modeled after those used for nonferrous mining projects, and (b) the temporary regulatory framework for permitting gas development projects regarding annual reporting should sunset once annual reporting rules specific for gas resource development projects are promulgated. As to each, the Band again encourages the DNR to defer decisions on permitting until a robust and comprehensive permanent framework has been developed with the benefit of Tribal consultation, pursuant to Minnesota Statute section 10.65. Once the comprehensive regulatory framework for gas development has been crafted, then the State's regulatory agency may implement proper annual reporting requirements and develop the annual reporting rules specific for gas resource development. Again, please note that though the recommendation cites Minnesota Statute 93.5174, subd. 8, the draft regulations at Section 14 have no such subdivision. There is a Section 15 for Temporary regulatory framework with items (1) through (6), but this is not explicitly marked as Minnesota Statute 93.5174, subd. 8.	Tribal_relations	Need for consultation
101	Recommendation DNR-10 includes two sub-recommendations: (a) a temporary regulatory framework for permitting gas development projects should include annual reporting requirements that are modeled after those used for nonferrous mining projects, and (b) the temporary regulatory framework for permitting gas development projects regarding annual reporting should sunset once annual reporting rules specific for gas resource development projects are promulgated. As to each, the Band again encourages the DNR to defer decisions on permitting until a robust and comprehensive permanent framework has been developed with the benefit of Tribal consultation, pursuant to Minnesota Statute section 10.65. Once the comprehensive regulatory framework for gas development has been crafted, then the State's regulatory agency may implement proper annual reporting requirements and develop the annual reporting rules specific for gas resource development. Again, please note that though the recommendation cites Minnesota Statute 93.5174, subd. 8, the draft regulations at Section 14 have no such subdivision. There is a Section 15 for Temporary regulatory framework with items (1) through (6), but this is not explicitly marked as Minnesota Statute 93.5174, subd. 8.	Process	Robust regulation
102	Recommendation DNR-11 includes two sub-recommendations: (a) prior to commercial production of gas resources, a gas resource development permittee should be required (as a permit condition) to submit to the DNR pump test data and other information derived from the gas wells drilled under the permit; and (b) the pump test data will be used to determine whether the associated spacing units and pool areas should be adjusted. However, DNR-11 only applies to the temporary regulatory framework, and is intended to sunset once the rules are promulgated. Due to the temporary nature of this recommendation, the Band reasserts its objection to permitting prior to the implementation of the permanent framework (see, e.g., Comments as to Recommendation DNR-8). In any event, as to Recommendation DNR-11(a), the Band agrees with this recommendation, but urges the DNR to add a provision related to inadvertent discoveries of gas and liquid resources, and should incorporate safety procedures through pump test data and other information derived from the wells drilled under the permit. The Band agrees with Recommendation DNR-11(b).	Process	Permits before full understanding
103	Regarding the Recommendation DNR-12, the Band agrees that a person applying for a gas resource development permit or permit amendment should be assessed fees to recover the costs incurred for environmental review. However, a fee schedule should also be set in statute such that there are clear understanding and expectations of what the assessed fees for gas resource development permit or permit amendment are.	Gas_production_permitting	Permit fee transparency
106	Regarding the Recommendation DNR-16, the Band agrees that money collected as part of financial assurance for gas resource development permits should be allowed to be invested by the State Board of Investment. But for this recommendation, financial assurances would not grow at the rate of inflation, reducing the amount and impact of the financial assurance over time.	Financial_assurance	SBI investment of FA
107	Regarding the Recommendation DNR-17, the Band reasserts that meaningful consultation should be conducted, followed by development and implementation of the permanent framework (see, e.g., Comments as to Recommendation DNR-8). Once consultation has been conducted under Minnesota Statute 10.65, a robust and comprehensive regulatory framework for gas development can be crafted, including rules on financial assurance.	Tribal_relations	Need for consultation
108	Regarding the Recommendation DNR-18, the Band agrees with the broad concept that the correlative rights of the owners of a shared gas resource should be protected. The Band agrees with the legal concept of "correlative rights" and that all rights holders should have access to the resources. However, knowing that there already are correlative rights issues with groundwater access in southwestern Minnesota, the Band urges the State to be conservative regarding authorizations to access gas resources, which may be more easily exploited than groundwater resources.	Correlative_rights	General
109	Regarding the Recommendation DNR-19, the Band is concerned with the recommendation that the State DNR commissioner be given statutory authority to establish or modify spacing units. Because gas exploration can quickly become gas extraction, we believe that this process is likely to be consistent with the industrial gas storage and transfer process, and that the Minnesota Pollution Control Agency (MPCA) is better equipped to provide technical expertise in these matters. Consequently, the Band recommends that the MPCA commissioner, and not the State DNR commissioner, be given statutory authority to establish or modify spacing units, with consultation with the State DNR and with the University of Minnesota State Geological Survey	Pooling_orders	Agency authority

110	Regarding the Recommendation DNR-20, the Band disagrees with the recommendation that the State DNR commissioner should have statutory authority to determine the process for establishing operator-proposed spacing units, and to collect and application fee for operator-proposed spacing units. First, the Band disagrees that the State should even consider operator-proposed spacing units, as operator's primary interest is generally focused on securing profit for themselves and their investors. The commissioner that is given the authority to establish or modify spacing units must be concerned first and foremost with the public interest and must protect the health of people and the environment. Revenue generation for the State should be a secondary goal, only after all other safety issues have been considered, and revenue from tapped resources should benefit all Minnesotans. Accordingly, the State must be responsible for establishing spacing units, and not the operator. The commissioner should have the authority to develop a fee schedule to impose on the operator related to the number of spacing units the operator chooses to utilize out of the total number of spacing units the State allocates to the operator for the project. But the State—and not the operator—must retain to the right to establish and enforce spacing units.	Spacing_unit	Who proposes spacing units
113	The Band agrees with the premise of Recommendation DNR-22(a), however, the Band recommends that the operator be required to secure the consent of owners of at least two-thirds of the mineral interest within a spacing unit to apply to the commissioner with authority for a pooling order that would combine all the mineral interests within a spacing unit for the development of gas resources for extraction within that spacing unit.	Pooling_orders	% of owner consent
114	Regarding the Recommendation DNR-22(b), the Band agrees with the recommendation to give the commissioner with statutory authority to issue pooling orders, and authority to determine the application process for pooling orders. However, the Band believes that because gas exploration can quickly become gas extraction, such an industrial framework should rest under the authority of the MPCA commissioner, and not the DNR commissioner.	Pooling_orders	Agency authority
115	Regarding the Recommendation DNR-22(c), the Band agrees with allowing the commissioner to impose fees for involuntary pooling order applications be set in statute. If a resource within the State is extracted, whether from voluntary or involuntary pooling, the State should recover the cost of action through fees. Establishing a set fee schedule in statute provides clear expectations to both the State and the operator. Such clarity and stability are needed to ensure smooth operations.	Pooling_orders	Application process
116	Regarding the Recommendation DNR-23, the Band agrees that processes and procedures must be put in place that allow an owner to challenge a proposed pooling order to protect the correlative interests of the owners of unleased mineral rights within a spacing unit, and that challenges should be resolved before a pooling order is issued.	Pooling_orders	Legal challenge process
117	Regarding the Recommendation DNR-24, the Band agrees that gas wells should not be drilled before a pooling order is issued for the associated spacing unit.	Pooling_orders	General
118	Regarding the Recommendation DNR-25, the Band agrees that statutory language should be adopted that describes how pooled mineral interests are managed during gas development operations, and how the correlative interests of nonconsenting mineral interest owners are protected by ensuring they receive a proportionate share of the profits from a gas resource development project. Clarifying procedures and establishing protections for nonconsenting owners will avoid conflict and streamline the management of pooled interests.	Pooling_orders	Compensation for nonconsenting owners
119	Recommendation DNR-26 includes two sub-recommendations: (a) that a person applying for a pooling order must present evidence to the commissioner that they have made reasonable offers, in good faith, to lease all of the mineral interests within a spacing unit; and (b) that the person applying for a pooling order must prove that they provided each owner relevant information about their ownership interests within the pooled area and informed them about the pooling procedures described in these new statutes and their options under these statutes. The Band agrees with each sub-part, and notes that transparency and fairness are important policy goals, particularly where nonconsenting owners may still be ordered to pool their mineral interests. …	Pooling_orders	Application process
121	Regarding the Recommendation DNR-28, the Band agrees that unleased mineral interests tied to an American Indian Tribe or Band owning reservation lands in Minnesota or owned by the federal government should be shielded from pooling orders. Additionally, any land tied to an American Indian Tribe or Band, regardless of whether or not it is reservation land in Minnesota, and any land owned by the Federal government on behalf of any American Indian Tribe or Band, regardless if in Fee or Trust, should be shielded from pooling orders, because the Tribe or Band may seek to convert Fee lands into Federal Trust on behalf of the Tribe or Band at any time in the future.	Pooling_orders	Shielding from pooling orders
123	Regarding the Legislative request for recommendation and statutory language regarding boring monitoring and inspection protocols, the Band recommends the State adopt, as a minimum standard, regulatory language on monitoring requirements similar to that in the California Code of Regulations, Title 14, § 1726.7.	Gas_wells	Well inspection
125	Regarding the Recommendation MDH-1, the Band Agrees that the Commissioner of Health's existing authority to explore and prospect for natural gas and oil should be repealed and the Commissioner should be granted new rulemaking and fee authority for the regulation of gas wells. However, there are no provisions in the existing or the proposed statutory language change in Minnesota Statutes 103I.005 defining when a boring becomes a well, as in the case of inadvertent discovery of gas resources while boring for mineral resources. If this is addressed in a different statutory section, then this should be referenced in Minnesota Statute 103I.005.	Gas_wells	Exploratory borings
129	Regarding the Recommendation MDH-4, the Band agrees that a person must submit a gas well construction notification and fee for each proposed gas well. If there are multiple gas wells that are connected for production purposes, the gas well construction notification must also disclose these connections and the relationship of each gas well to other connected wells.	Gas_wells	Well construction
130	Regarding the Recommendation MDH-5, the Band agrees that a person must grant the Commissioner of Health access to a gas well site to inspect. However, all regulatory agencies, and not just the MDH, must have the ability to inspect a well site for their regulatory jurisdictional subjects.	Gas_wells	Well inspection
131	Regarding the Recommendation MDH-6, the Band agrees that a person must notify the Commissioners of Health, Natural Resources, and the Pollution Control Agency of an occurrence during a construction or sealing of a gas well that has a potential for significant adverse public health or environmental effect.	Gas_wells	Notifications
132	Regarding the Recommendation MDH-7, the Band agrees that a person must not use a gas well to inject or dispose surface water, groundwater, or any other liquid, gas, or chemical. The Band also has concerns that any groundwater brines may be high in salinity, or may have dissolved minerals of value. The Band therefore recommends that any dissolved salts and minerals from groundwater brines should be extracted, to the greatest extent possible, prior to treating and then disposing of, the remaining wastewater.	Health_and_environmental_quality	Saline water
133	Regarding the Recommendation MDH-8, the Band heartily agrees that a person is prohibited from hydraulic fracturing a gas well.	Health_and_environmental_quality	Hydraulic fracturing
134	Regarding the Recommendation MDH-9, the Band agrees that a person must ensure that drilling fluids, cuttings, treatment chemicals, and discharge water are disposed of according to federal, state, and local requirements. This rule should also cite to and incorporate the specific Federal and State requirements.	Gas_wells	Well construction
135	Regarding the Recommendation MDH-10, the Band agrees that drilling fluids used during the construction of a gas well must be water or air based. With regard to additives, the Band recommends that the additives must meet the requirements of NSF/ANSI/Can 60-2024 Standard.	Gas_wells	Well construction
136	Regarding the Recommendation MDH-11, the Band agrees that a person must meet gas well casing and grout requirements. The Band recommends that a person specifically must meet API Specification 5CT (11th Edition) gas well casing and grout requirements.	Gas_wells	Well construction

137	Regarding the Recommendation MDH-12, the Band agrees that a person must meet gas well isolation distances. However, because some gasses are heavier than air, and have the potential to asphyxiate personnel in the vicinity without proper personal protection equipment, the Band recommends a person must not place, construct, or install a gas well less than 1,600 feet from a residential building; 1,600 feet from a water supply well; or 3,200 feet from a school facility or a care facility, such as childcare centers, nursing homes, hospitals, and clinics.	Gas_wells	Well setbacks
138	Regarding the Recommendation MDH-13, the Band agrees that a person must protect groundwater during the construction and sealing of a gas well.	Gas_wells	Well construction
139	Regarding the Recommendation MDH-14, the Band agrees that a person must seal a gas well to prevent contamination of groundwater and the environment, but also recommends that a gas well sealing notification be valid for 18 months from the date filed, consistent with Minnesota Administrative Rules 4725.1832.	Gas_wells	Well construction
140	Regarding the Recommendation MDH-15, the Band agrees that a person must submit a gas well sealing notification and fee for each proposed gas well to be sealed, and recommends that a gas well sealing notification be valid for 18 months from the date filed, consistent with Minnesota Administrative Rules 4725.1832.	Gas_wells	Notifications
141	Regarding the Recommendation EQB-1, the Band agrees with the recommendation to require a mandatory environmental assessment worksheet (EAW) for any gas resource development project. However, since any exploratory boring operation potentially can become a gas resource development, we recommend that any boring operation greater than 985-ft (300-m) require an EAW, and any gas resources extraction require an Environmental Impact Statement (EIS).	Environmental_review	Need for comprehensive EIS
142	The Band, also believes that the DNR should not be designated as the responsible government unit (RGU). The Band believes that the extractive operations related to natural case more closely resemble industrial activities in which the Minnesota Pollution Control Agency (MPCA) regulates. Consequently, the Band recommends that the State designate MPCA as the RGU for gas resources development, extraction, and injection.	Environmental_review	MPCA should be RGU
143	Regarding the Recommendation PCA-1, the Band agrees that Minnesota currently has permitting rule and regulations in place to regulate the proposed gas extraction industry. However, Minnesota does not have the necessary framework for underground gas storage/sequestration, which the State should consider in the permanent rules and regulations. If the State does not have primacy in this, then the United States Environmental Protection Agency must implement the regulatory framework on behalf of the State.	Process	Need underground gas storage framework
144	The Band appreciates that the MPCA will comply with Minnesota Statute Section 10.65 which requires timely and meaningful consultation between the State and Tribal governments on matters under MPCA's authority that may have Tribal implications. However, this requirement applies to all State agencies and departments identified in Minnesota Statute Section 10.65, not only MPCA. The Band is disappointed that other GTAC member agencies have not explicitly identified this responsibility.	Tribal_relations	Need for consultation
145	Thus far in this process, the State agencies have done a good job in information sharing for technical coordination, and the Band has appreciated the technical information sessions the State has provided. Although Band technical staff have briefed Band leadership regarding GTAC's activities, and the State has also provided technical briefing to Band leadership, the State has fallen short of meaningful government to government consultation with Tribes. Meaningful consultation is a political act between sovereigns, and a dialogue regarding possible impacts to each Party's sovereignty. This conversation is separate, but not isolated, from the technical merits of the regulatory issues at hand.	Tribal_relations	Need for consultation
147	Regarding Recommendation DOR-5, the Band encourages the Department of Revenue and other GTAC member-agencies to carefully consider whether, and under which specific circumstances, to apply the same exemptions and exclusions for gas and oil producers that exist for other mining operations. The Band is concerned that granting tax exemptions and exclusions to extractive industries may limit benefits to the general public related to the extraction of shared resources.	Revenue_generation	Tax exemptions
148	Please adjust the section numbers as follow: Section 8. 93.5152 to Section 8. 93.5153 This is because there already is a Section 7. 93.5152 Section 9. 93.5153 to Section 9. 93.5154 Adjusting Section 8. causes adjusting Section 9. Section 20. Items (5)–(14) to Section 20. Items (7)–(16) This is because Section 15. contains Items (1)–(6). 103I.001 to Section 23. 103I.001 103I.005 to Section 24. 103I.005 103I.706 to Section 25. 103I.706 103I.707 to Section 26. 103I.707 103I.708 to Section 27. 103I.708 116D.04 to Section 28. 116D.04 Section __. 272.02 to Section 29. 272.02 Section __. 272.03 to Section 30. 272.03 Section __. 273.01 to Section 31. 273.12 Section __. 289A.02 to Section 32. 289A.02 Section __. 289A.12 to Section 33. 289A.12 Section __. 289A.19 to Section 34. 289A.19 Section __. 290.0134 to Section 35. 290.0134 Section __. 290.0135 to Section 36. 290.0135 Section __. 290.05 to Section 37. 290.05 Section __. 290.923 to Section 38. 290.923 Section __. 297A.68 to Section 39. 297A.68 Section __. 297A.71 to Section 40. 297A.71 Section __. 298.001, subd. 3a to Section 41. 298.001, subd. 3a Section __. 298.001, subd. 10a to Section 42. 298.001, subd. 10a Section __. 298.001, subd. 14 to Section 43. 298.001, subd. 14 Section __. 298.001, subd. 15 to Section 44. 298.001, subd. 15	Process	Statutory language

150	Hello. My name is Jack Gibbons. I'm a consultant geologist with Pulsar Helium. I grew up in Northern Wisconsin, in an historic iron mining town. I currently live in Duluth. My wife grew up in Duluth. She's a fifth generation Duluthian on her dad's side, and fourth generation on her mom's side. I attended Carlton College for my undergraduate degree and Colorado School of Mines and University of Arizona for my graduate degrees, focussing on hard rock mining projects in northern Ontario and Chile. I currently work for a mining consulting group based out of Denver. I've supported mining projects all across the western U.S., Canada and South America. And how I'm connected to Pulsar, back in 2011, I was working for Duluth Metals when they made the original discovery. And I was reconnected with a project last year with Pulsar was working on Jet Stream 1. I came up to support the contract geologists with logging geology of the jet stream. Since the majority of my work is in the western U.S. and internationally, it is very meaningful to me to have an opportunity to support a natural resource project here in Northeastern Minnesota. My current role at Pulsar is two-fold. I support different community projects, including characterizing the reservoir rocks and the composition of the gas, itself. I also coordinated with regional companies that are interested in the project. On the less technical side of things, I'm engaged with people interested in the project, local media, state representatives. And I also lead tours for potential investors. That's kind of where I'm at. I just wanted to be on the record, just, I'm grateful to have a natural resource project here in Northern Minnesota and grateful for the work that Pulsar is doing; and also, grateful for the GTAC community members for organizing this, and you know, promoting their framework.	Process	General
151	Regarding permitting of gas exploration and production permitting, please do continue expediting the development of the full process for both. I have visited the Babbitt site, as I assume you have, and it is a clean, well run project. This is a huge employment opportunity for Minnesota, and if the process gets bogged down, the early developers will move elsewhere. Please do not screw this up. Minnesotan's need it, and there are zero environmental issues.	Process	General
152	Thanks for the opportunity. This is obvious but please preserve all of our wildlands and waters. Please honor Native American requests, they should be respected.	Tribal_relations	Usufructuary rights
153	from what i have read there seems to be little impact to the enviroment and the helium is a vital resource... sometimes you have to compromise for the benifit to us all.	Process	General
154	We are seasonal residents in the Isabella area and use Highway 2 regularly throughout the year....driving past Dunka Road where the Topaz Helium Project between Isabella and Babbitt is being (considered) planned. As stated on the website, "Minnesota has untapped and unexplored potential for both geologic hydrogen and helium resources. With no history of gas production in the state, Minnesota needs a framework that would regulate these emergent industries to properly protect natural resources and human health, develop a fair royalty structure on state-managed lands and ensure the conservation of the state's natural resources." We are not able to attend either of the public meetings in Biwabik or in Eagan, but would like to ask a few questions which I hope can be addressed and considered. Questions regarding the Topaz Helium project between Isabella and Babbitt: (1) What are the plans for a preliminary Environmental Quality Worksheet (EAW)? (2) If the developing issues raised in that study (EAW) are sufficiently concerning, will the public be entitled to an Environmental Impact Statement (EIS) on the project without obstruction of the DNR?	Environmental_review	Need for comprehensive EIS
155	(3) Additionally, how will residents and travelers be considered as you make your decision allowing the project to potentially move forward? (As mentioned, we live in Duluth but are ALWAYS..... year round.... on Highway 2 from Two Harbors toward Highway 1, and vice versa driving by Dunka Road regularly.) As you have stated, there are no rules on the books at this time so how will the Topaz project be treated (and how will those of us who drive by that area during the exploration and extraction of the helium need to worry about drilling noise, nocturnal lighting, and dust?) Thank you and we do hope the questions above will be considered when you make your decision....and we do hope whatever decision you reach will truly be thoroughly researched and not hurried to reach a conclusion to benefit an industry before the people of Minnesota.	Environmental_review	Noise / light
156	Good Afternoon I live about six miles as the crow flies from the Topaz drill site in Section 17 Stoney River Township. I am all for the development of this project.	Process	General
157	The ONLY reservation I have is light pollution of our dark sky. We could actually see a bright light at night from our house on top of the drill rig when they sent down the test pipe. Currently we do not see any light now. When that site is developed and expanded into production. I strongly encourage all efforts to avoid bright lights at night. If the entire site lights brightly, or has illumination high in the air it will negatively affect our property value since our "view" adds significant value to our homestead. It should be noted that our "high spot view" was used daily as THE Observation Post by the USFS during the course of the Greenwood fire. I encourage anyone from both the DNR, Legislative branch or Pulsar to feel free to contact me to set up a visit.	Environmental_review	Noise / light
158	All the welding Gas suppliers are able to pull gases from the air. Thins just another government overreach.	Process	General

159	Good morning, I´m seeking some clarification please on the Regulatory Framework for Developing Gas Resources in Minnesota. I¨m looking at this page https://gasproductionrules.mn.gov/project-timeline.html Am I correct in stating that currently there are no permits for gas extraction and that as yet there is no temporary framework for gas development projects? What is the earliest that temporary legislation to enable gas projects might be enacted? May 2025? And if legislation for a temporary framework is not passed in May 2025, then how long until new legislation that might enable gas projects to be permitted? Another question please: are not Minnesota law makers overall positive towards gas development projects in the state? Also, which tribal nations would need to be consulted in the base of the Pulsar Helium / Topaz project? Am I correct in saying that if tribal nations are not in agreement then the Topaz project could not go ahead? Also, are there plans for a helium pipeline in Minnesota to take helium from the Topaz project to Duluth port? Seems a long way and expensive to transport the helium from the well-heads by truck. Many thanks for your time and have a wonderful weekend.	Process	General
160	Good morning, I´m seeking some clarification please on the Regulatory Framework for Developing Gas Resources in Minnesota. I¨m looking at this page https://gasproductionrules.mn.gov/project-timeline.html Am I correct in stating that currently there are no permits for gas extraction and that as yet there is no temporary framework for gas development projects? What is the earliest that temporary legislation to enable gas projects might be enacted? May 2025? And if legislation for a temporary framework is not passed in May 2025, then how long until new legislation that might enable gas projects to be permitted? Another question please: are not Minnesota law makers overall positive towards gas development projects in the state? Also, which tribal nations would need to be consulted in the base of the Pulsar Helium / Topaz project? Am I correct in saying that if tribal nations are not in agreement then the Topaz project could not go ahead? Also, are there plans for a helium pipeline in Minnesota to take helium from the Topaz project to Duluth port? Seems a long way and expensive to transport the helium from the well-heads by truck. Many thanks for your time and have a wonderful weekend.	Tribal_relations	Need for consultation
161	Good morning, I´m seeking some clarification please on the Regulatory Framework for Developing Gas Resources in Minnesota. I¨m looking at this page https://gasproductionrules.mn.gov/project-timeline.html Am I correct in stating that currently there are no permits for gas extraction and that as yet there is no temporary framework for gas development projects? What is the earliest that temporary legislation to enable gas projects might be enacted? May 2025? And if legislation for a temporary framework is not passed in May 2025, then how long until new legislation that might enable gas projects to be permitted? Another question please: are not Minnesota law makers overall positive towards gas development projects in the state? Also, which tribal nations would need to be consulted in the base of the Pulsar Helium / Topaz project? Am I correct in saying that if tribal nations are not in agreement then the Topaz project could not go ahead? Also, are there plans for a helium pipeline in Minnesota to take helium from the Topaz project to Duluth port? Seems a long way and expensive to transport the helium from the well-heads by truck. Many thanks for your time and have a wonderful weekend.	Process	Robust regulation
162	The following does not try to represent the SWCD Board. or Lake Co. I only claim to represent myself and people in District. 2. by making these recommendations. 1. I live 2 1/2 air miles from the site which I toured about a year ago with an invited group of local interested people. We were shown several tons of drilling aids stacked on pallets and contained in either bags or sealed buckets. Drilling effluent covered the site. The drilling effluent should be tested for PFAS chemicals and all drilling materials should be forced to list all ingredients they contain. This would make it in compliance with the recently enacted Amara's Law.	Gas_wells	Well construction
163	2. If this enterprise wishes to be a good neighbor to all Minnesotans then it should be done cleanly and quietly. The current site is surrounded by Commons properties and a Scientific and Natural Area. The area is home to endangered species and species of concern. We already have contaminated lands and waters from other mining activities in nearby areas and we don't want more.	Environmental_review	Environmental impacts
164	3. The 8.5 parts CO2 should be sequestered in a scientifically approved site and not made to produce more CO2 products. This would be in line with the MN State goal of eventual carbon neutrality.	Environmental_review	Carbon and climate change
165	4. The State and IRRRB might have some ability and desire to help establish one or two large solar arrays with appropriate battery back ups for expected uses. Transportation trucks should be quiet electric engine vehicles without Jake Brakes, and without the tire chemicals that stop fish reproduction. All extraction, compression sites should have very low decibels allowed, with all appropriate mufflers and sound barriers in place for all operations. I personally listened to about 6 months of continuous 24/7 low volume noise from 2 1/2 miles away as did a number of neighbors and all the area wildlife that depend on their ears for survival. Not only did this 24 /7 noise bother daily it was sometimes loud enough to carry through closed windows. Sound carries very well in the cold air of winter at the top of the watershed.	Environmental_review	Noise / light
166	5. Thus I would recommend the extraction, separation, compression, and transportation sites and vehicles be subject to a full Environmental Impact Statement.	Environmental_review	Need for comprehensive EIS
167	6. Meanwhile, before the State gives more permits for exploratory drilling it should get its mapping and history of previous exploratory bore holes updated. Last I looked it was impossible to determine how many of the old bore holes have been permanently sealed according to law and how many remained open as potential sources of aquifer contamination. Twin Metals says they have permanently sealed all their bore holes yet as of a year ago that's not what State mapping showed.	Gas_wells	Exploratory borings
168	Vema is interested in the GTAC's proposed gas resource development framework because Minnesota's iron ranges and mining infrastructure combined with Vema's Stimulated Geologic Hydrogen process could make the state a global leader in clean hydrogen production.	Process	Robust regulation

169	Vema strongly recommends revising the Exploratory Boring definition to specifically include Stimulated Geologic Hydrogen. Stimulated Geologic Hydrogen prospects do not have any gas in the subsurface before the stimulation is started, and the exploratory borings are not used for stimulation or production. Exploratory Borings for Stimulated Geologic Hydrogen are more analogous to borings for metallic minerals than to other gas wells. The borings are needed to measure the subsurface characteristics of the stimulated geologic hydrogen resource, which are needed to finalize the design of our first gas wells. Borings used for Stimulated Geologic Hydrogen are temporary and are not used for stimulation or production. These borings are drilled with very little surface disturbance using small geotechnical or water well drilling rigs. Without the measurements from exploratory borings, a Gas Resource Development Project permit for a Stimulated Geologic Hydrogen project will rely on many estimates, which will change before any producing gas well is drilled.	Gas_wells	Exploratory borings
170	Vema recommends that the 'Resources Development Permit' review process follows the EPA's latest 'Guidance for Review and Approval… #34' – including a defined "maximum time limits for completion of reviews by all o�ices", rules preventing "old issues [being] reopened unless there are material changes in the application", and "there should be some distinction between major objections which must be resolved before program approval and comments of a more advisory nature." https://www.epa.gov/uic/guidance-documentsreview-uic-primacy-applications-and-program-revisions	Gas_production_permitting	General
171	Similar to feedback on DNR-4, Vema recommends that temporary exploratory borings used for Stimulated Geologic Hydrogen are considered similarly to metallic minerals Exploratory Borings.	Gas_wells	Exploratory borings
172	The proposed $50,000+ Application Fee and $75,000 Annual Development Fee are extremely high, and would materially increase the cost of gas resource exploration in Minnesota. Vema recommends that the state consider a tax structure similar to other states, with lower administrative fees and a severance tax. It is important to distinguish between the economics of geologic hydrogen and helium wells. The 'per well' revenue from Stimulated Geologic Hydrogen is not close to the 'million dollars a day per [helium] well' referenced in the DNR's explanation. The energy transition depends on clean hydrogen being cost-competitive with fossil fuel derived hydrogen. High fees and taxes disincentivize exploration and production for hydrogen.	Gas_production_permitting	Permit fees too high
173	The MDH recommends carving an exception into 103I.707 Subd.4 to allow Class 2 injection wells approved by the EPA. Vema's Stimulated Geologic Hydrogen process requires injecting water into a Class 5 injection well approved by the EPA. Vema recommends that the changes to 103I.707 Subd.4 also allow "Class 5 injection wells approved by the EPA used for Stimulated Geologic Hydrogen production".	Health_and_environmental_quality	Class II injection wells
174	The definition of Hydraulic Fracturing (see below, from 1031.707.e) is vague, which may cause conflict with Stimulated Geologic Hydrogen developments. Vema's process will very slowly propagate permeability into the target formation by displacing and reacting with minerals in the formation. The permeability growth is controlled by the low injection pressure and a 'confining zone' which isolates the growth from usable water resources. The pressure is defined by the EPA's permitting process. - "Hydraulic Fracturing Treatment" means all stages of the treatment of a well by the application of fluid under pressure that is expressly intended to initiate or propagatefractures in a target geologic formation to enhance production of oil and gas. Vema recommends revising the definition of "Hydraulic Fracturing Treatment" to below.... - "Hydraulic Fracturing Treatment" means all stages of the treatment of a well by the application of fluid under pressure at rates above 10 barrels per minute that is expressly intended to initiate or propagate fractures in a target geologic formation to enhance production of oil and gas.	Health_and_environmental_quality	Hydraulic fracturing
175	Recommendation EQB-1: Require a mandatory environmental assessment worksheet (EAW) for any gas resource development project. The DNR will serve as the responsible governmental unit (RGU). � Similar to feedback on DNR-4, Vema recommends that temporary exploratory borings used for Stimulated Geologic Hydrogen are considered similarly to metallic minerals Exploratory Borings.	Environmental_review	No mandatory EAW for exploration
176	Recommendation DOR-2: Incorporate gas and oil into existing Gross Proceeds Tax. Recommendation DOR-3: Modify the Gross Proceeds Tax rate section to allow different tax rates for di�erent gases, minerals, and oils. � Vema recommends that the Gross Proceeds Tax rate for Stimulated Geologic Hydrogen wells is distinct and di�erent than the rate for Helium wells, and that the tax rate accounts for the commodity price for Hydrogen (~$1 per kg).	Tax_distribution	Different tax rates
177	DNR-1: Suggest that the applicability of state rules apply to all oil and resources, whether expedited or permanent. This would create standardization and efficiencies if new resources are discovered in the State.	Process	General
178	DNR-3: Suggest considering the differences between Oil & Gas (O&G) development and hardrock mining when establishing policies and frameworks. The process of advancing from exploration to development is fundamentally different, i.e. hardrock exploratory borings are purely exploratory where O&G borings can be converted to production wells without further investigations. This can necessarily remove the production planning, review, and analysis required by hardrock mines.	Gas_production_permitting	Mine permitting not best model for gas permitting
179	DNR-4,-5,-6: Suggest minimum requirements for the submission of proposed activities to better inform the permitting decision. The rules should clearly define applicability to various surface and mineral estate status, including special management areas. The permitting process should also include a method for determining ownership of the resource in fractional interest scenarios. Additionally, the regulatory framework should allow for cooperative agreements with other management agencies.	Process	Robust regulation
180	DNR-10: Suggest that the regulatory framework contain robust reporting and compliance standards to ensure compliance with the permitting terms and conditions, as well as all applicable statues and rules. This should necessarily include a well- defined process for noncompliance.	Health_and_environmental_quality	Compliance monitoring
181	DNR-14,-15,-16,-17: Suggest establishment of long-term trusts with the appropriate agencies designated as the beneficiaries to address liabilities. This approach better positions agencies with the financial resources required to address long-term reclamation or management issues. Traditional sureties, letters of credit, and cash investments generally are not capable of generating interest to fund reoccurring, long-term costs.	Financial_assurance	FA structure
182	DNR-19: Consider consulting or adopting the Bureau of Land Management's guidance on oil & gas leasing acreage limitations at 43 CFR § 3101.21 through § 3101.40	Process	Leasing
183	DNR-22,-23,-24,-25,-26: Suggest clearly stating the circumstances under which minerals may be produced without consent, i.e. is there a condemnation process, what formula determines just compensation to mineral rights holder, etc.	Pooling_orders	Compensation for nonconsenting owners
184	DNR-28: Suggest changing "should" to "shall." The State of Minnesota does not have the authority to manage mineral interests owned by the U.S. Government. This authority resides with the Department of Interior, Bureau of Land Management and in certain case shared jointly with the Department of Agriculture, Forest Service. Should also clearly discuss offsets to Tribal and Federal minerals to prevent "line drilling" and the extraction of Tribal and U.S. Government minerals without consent.	Pooling_orders	Shielding from pooling orders
185	EQB-1: All proposals, even those under not under the temporary framework, should be assessed for significant effects. Coordination with all stakeholders--private and governmental--should be an integral part of the process. In general, a successful exploratory gas well is likely to be converted into a permanent extraction site so each should be considered for potential long-term effects.	Environmental_review	Need for comprehensive EIS

186	MPCA-1: At a minimum, permittees should adhere to MSHA and EPA standards regarding above ground storage tanks.	Gas_production_permitting	Need for all required permits
187	With the discovery of helium resources and the potential for naturally generated hydrogen resources, Minnesota has been presented with an exceptional and unique opportunity to provide for multiple domestic industries including semiconductor manufacturing, medical technologies, clean energy infrastructure, and more. Our opportunity will become a reality only with the development of a regulatory system that encourages exploration at the front end and supports responsible development after discovery.	Process	General
188	Throughout the proposed regulations, there is an assumption that gas resource exploration will result in a gas resource development facility or operation. The 2024 legislation, as supported by the industry, clearly delineated for each agency if their responsibility was for “exploration and appraisal of gas and oil resources” or “gas and oil production.” The Minnesota Department of Health (MDH) was solely directed to focus on “exploration and appraisal of gas and oil resources” whereas the remaining agencies, including the Environmental Quality Board and the Minnesota Department of Natural Resources (MNDNR) were to focus on “gas and oil production” only. This distinction was also incorporated into the moratorium placed by the legislation on gas production, stating that the MNDNR “may not grant a permit for the production of gas or oil [emphasis added] unless the legislature approves a temporary permit framework that allows issuance of temporary permits.” The legislation encourages continued exploration during this period of rulemaking; however, the proposed rules do not support that intention.	Gas_wells	Exploratory borings
189	Exploration activities for gas resources should be treated the same way as exploration activities and drilling to understand potential hard rock mineral resources. It is not practical or reasonable to require environmental review for exploratory gas wells that may or may not be feasible to develop further. Once a resource has been determined to be worth pursuing for development, then a project plan would be developed with adequate information needed to complete necessary environmental review and permitting. Until that need is established, there are adequate protections within state regulations to protect neighboring natural resources.	Environmental_review	No mandatory EAW for exploration
190	The second item for further discussion and evaluation includes the structure proposed for application fees, annual permit fees and construction and sealing of wells. The proposed application and annual permit fees are not proportional to the scale of the potential gas resource development facilities when compared to ferrous and nonferrous projects, including scram and peat mining. In addition, the current proposal requires a fee of $76,000 for construction of gas wells and $50,000 for sealing of those wells. Current Minnesota statutes for water wells have a $275 fee for construction and $75 fee for sealing. Given that exploration does not equate to guaranteed discoveries, these well construction and sealing fees actively discourage exploration activities that would further our understanding of Minnesota’s helium and hydrogen resources.	Gas_production_permitting	Permit fees too high
191	Finally, the proposed Section 18. 93.5177 Environmental Review Fees requires gas resource development permit applicants to pay for the complete development of an Environmental Assessment Worksheet (EAW). This language unjustly separates out this promising sector as there is no other provision in state law that grants responsible government units (RGUs) the authority to assess costs for an EAW.	Environmental_review	EAW and EIS costs
192	Minnesota has been presented with a rare opportunity to develop identified helium resources and potential hydrogen resources. As a state, we have historically taken great pride in our medical technology industry that relies on helium, and we have celebrated the announcement of the Heartland Hydrogen Hub award from the U.S. Department of Energy. With a thoughtful, fair regulatory framework, these untapped resources could allow Minnesotans to provide for these technologies from the ground up.	Process	General
193	I am happy to offer comments to the GTAC regarding new rules for an exciting industry, Helium that has the potential to promise new economic benefit to our communities, local municipalities, and schools.	Process	General
194	We would encourage the rulemaking authorities to support the current two-step process for this new industry. However, the draft indicates that an Environmental Assessment Worksheet (EAW) be required for exploration. This means an EAW for every exploration hole. This is inconsistent with current mining exploration practices and rules. This would unnecessarily delay the exploration phase. Instead, we would encourage the requirement for an EAW at the production phase of beneficiation. Please allow for exploration, then phases of development, which have the built-in process for appropriate environmental review. We support basic permitting consistent with our other mineral assets.	Environmental_review	No mandatory EAW for exploration
195	Additionally, whatever is created, our local communities must continue to benefit from the resources in our region. RAMS supports rolling the royalty process into existing mining laws, especially incorporating gas and oil into the Gross Proceeds Tax (in lieu of property taxes), promoting consistent application and beneficiation strategies across local communities and the state. The assumptions under draft warrant further examination and discussion, and Range communities need to be at the table. We support what is fair and equitable, in spirit of severance tax systems, for both the region and any company wishing to explore the resource.	Tax_distribution	General
196	The development of gas projects differ significantly from mining operations for nonferrous metals and other minerals. Accordingly, Iron Range urges GTAC to adopt statutes and regulations specifically tailored to address the unique characteristics and operational needs of gas production.	Gas_production_permitting	Mine permitting not best model for gas permitting
197	As outlined in this submission, gas operations rely on industry-specific terminology and practices that are not only integral to effective regulation but also critical for applying established legal jurisprudence. (They encourage GTAC to work with a proposed list of terms and definitions attached to their letter).	Process	General
198	Iron Range encourages GTAC to design a regulatory framework that draws upon the well- established body of legal jurisprudence developed around gas production. Leveraging this existing foundation will allow Minnesota to benefit from guiding and binding precedents that have been extensively tested in other jurisdictions. Furthermore, basing new statutes and regulations on these proven frameworks will streamline the development of gas projects while ensuring robust protections for stakeholders and the environment.	Process	Robust regulation
199	DNR-1: Iron Range recommends that the temporary framework and expedited rulemaking focus on gas development and production as its own unique industry. Iron Range does not believe that such a focus will cause unnecessary complexity or delay. Instead, such a focus will enable GTAC and the State of Minnesota to establish a clear and useful framework for the development of gas within Minnesota that will be applicable to the various forms of gas development undertaken by gas operators in the state both now and in the future.	Process	Robust regulation
200	Iron Range Comment on “Natural Gas” Definition: Iron Range opposes not defining “natural gas” because natural gas has unique and specific properties. A proposed definition is below in Appendix I.	Process	General
201	Iron Range recommends that a single agency, that being the DNR, oversee gas operations, including the plugging and abandonment of gas wells. Iron Range believes that the DNR has the requisite agency mandate to oversee all gas operations in Minnesota. Further, oversight of water wells and gas wells are markedly different. While water resources must be protected during gas production, developing and implementing proper gas statutes and regulations through a single agency can achieve the water protection objectives sought by GTAC.	Process	General
202	In MDH-2, GTAC proposes clarifying the definition of “well” as currently defined in Minnesota Statutes Section 1031.005, subdivision 21, to confirm that a “well” as contemplated by GTAC’s proposed statutory changes does not refer to a gas well. Iron Range recommends that suitable definitions for gas wells be adopted and implemented because across gas operations, these definitions classify gas wells based upon the amount of petroleum product produced from each.	Gas_wells	Well construction

203	DNR-7 proposed permit application and annual permit fees: While it is important for DNR to have the necessary resources to ensure efficient and effective permitting, including technical staff, these permit fees are vastly higher than the fees in other jurisdictions and would likely prevent smaller gas operators from undertaking operations in Minnesota. Iron Range supports a permit review application fee up to $5,000 but objects to an additional annual fee. This fee structure may be appropriate for mining development, which requires significant surface disturbance and environmental assessments; however, gas development has a much smaller footprint and lesser impact to the surface, therefore, a smaller fee is appropriate.	Gas_production_permitting	Permit fees too high
204	Associating costs of legal fees, which are wholly speculative in nature, with the review of permits is not acceptable to Iron Range or others seeking to engage in gas development in Minnesota.	Gas_production_permitting	Permit fees too high
205	In DNR-3, GTAC proposes using "existing statutes and rules for permitting of mining projects as a model for establishing comparable permitting requirements and policies for gas resource development." Iron Range believes that existing Minnesota statutes and rules will only serve as limited guidance in the development of gas regulations because they were developed for mining instead of gas development. Due to the unique nature of gas operations, it is critical for GTAC and the State of Minnesota to develop a regulatory framework specifically for gas operations.	Gas_production_permitting	Mine permitting not best model for gas permitting
206	Iron Range urges GTAC to review the following state statutes and regulations to develop a perspective on frameworks that can be drawn upon to establish a comprehensive, durable, and efficient regulatory scheme for Minnesota. (references for New Mexico, Texas, ND, and CO)	Process	Robust regulation
207	In DNR-4, GTAC proposes requiring permits for gas resource development projects prior to drilling gas well. Iron Range agrees with this requirement and encourages GTAC to develop a permitting process that will ensure transparency on the information needed to obtain a permit and establish a clear timeframe for review and approval of permit submissions.	Gas_production_permitting	When is a permit needed
208	In DNR-5, GTAC proposes that permits should apply to "gas resource development locations" where gas development and operations disturb the ground surface. Iron Range Comment: The definition of "gas resource development locations" should be refined to focus solely on high-impact sites, such as drill pads and immediate operational areas. Ancillary structures like enrichment plants or temporary storage facilities should be regulated under separate frameworks, if necessary, to avoid burdening operators with duplicative or overly broad permitting requirements.	Process	Burdensome regulations
209	The surface is important, without exception, the development of the mineral estate (commonly referred to as "subsurface estate or "mineral estate" or "dominant estate") is dependent upon the spacing rules governing the surface estate for the development of the mineral estate. Accordingly, both surface and mineral estates should be addressed as part of the permitting process to ensure efficient gas development and to protect correlative rights.	Correlative_rights	General
210	In DNR-6, GTAC proposes limiting the extraction of gas wells at permitted gas resource development locations. Iron Range Comment: Iron Range urges GTAC to consider that gas production originates from complex geologic formations that often does not reflect the footprint of the surface estate or development characteristics, especially when considering gas produced through directional drilling operations.	Gas_production_permitting	When is a permit needed
211	Temporary Permitting for Exploration: Regulations should allow for a temporary permitting process to authorize limited gas extraction utilizing exploratory drilling operations. Such a process could include requirements for the use of appropriate blowout prevention systems and drilling materials to mitigate risks, while still enabling operators to evaluate the available subsurface resources. This would help balance safety and environmental protection with operational needs.	Gas_production_permitting	When is a permit needed
212	Clarify or Change the definition of "Gas Extraction": The proposed regulation should clarify what constitutes "gas extraction" from exploratory borings, more properly referred to as "drilling." For example, small-scale test extractions for resource evaluation purposes should not be equated with full-scale production and should not require a gas resource development location permit. Any ambiguity in the definition of "gas extraction" could create unnecessary compliance burdens for operators conducting routine drilling exploration activities. Iron Range recommends replacing "gas extraction" with "gas production" and "gas drilling operations."	Gas_wells	Exploratory borings
213	In DNR-8, GTAC recommends that gas resource development permits issued during the rulemaking under a temporary framework continue to remain valid and in place after the rulemaking process. Iron Range Comment: Iron Range agrees. However, GTAC should provide clarity around what an amendment to the initial permit requiring a new permit under the temporary and final rules so that nominal changes, e.g., changes to operator names or well names, do not require an entirely new permit and the associated fees and processes. Only material changes (e.g., significant depth variances for the initially proposed well, the including of additional pools and formations, etc., should require permits to be amended) to the permitted operations should require a new permit.	Gas_production_permitting	Temporary permits
214	The initial (gas resource development) permit should also enable the operator to apply for extensions to permitted development plans without incurring additional fees.	Gas_production_permitting	Permit fee transparency
215	In DNR-13, GTAC proposes that contested case hearings be held for "challenges to gas resource development plans." Iron Range Comment: Iron Range agrees that a contested case hearing process should be established. However, the contested case hearing process should be properly limited and should not be used as a means for members of the public or competitors to contest previously approved gas drilling operations generally. Members of the public should be allowed to make public comments during contested case hearings. However, once Minnesota establishes a framework for gas development, the contested case hearing process should be used for operators to propose competing development plans and for the state to assess and approve those plans that protect correlative rights.	Process	Contested case and legal
216	Gas development proceedings in other states are fact intensive undertakings requiring substantive input, including time consuming and costly reports and studies from petroleum geologists and various engineers. Requiring operators to repeatedly present findings from these types of experts is not conducive to prudent operations or to gas development. Accordingly, GTAC must ensure that the public is able to express concerns and obtain certain information through the contested hearing process without unnecessarily subjecting operators to ongoing time intensive and costly proceedings.	Process	Contested case and legal
217	Iron Range encourages GTAC to examine the contested case hearing process in other states for purposes of developing a contested case hearing process that ensures public participation while also balancing prudent, efficient, and expedient gas project development in Minnesota.	Process	Contested case and legal
218	In MDH-1, GTAC proposes repealing the Commissioner of Health's authority to explore and prospect for oil and natural gas. Iron Range Comment: In general, Iron Range concurs that referring to gas exploring as "boring" instead of "drilling" is inaccurate. Further, "prospecting" for gas is more specifically referred to as "wildcatting" or "exploring."	Gas_wells	Exploratory borings
219	(E)ven though there is currently no indication that oil exists in paying quantities in Minnesota, as petroleum technology improves, it is possible that additional oil and gas resources may be identified. Accordingly, Iron Range recommends that GTAC develop statutes and regulations consistent with broader gas development practices.	Process	Robust regulation
220	In MDH-3, GTAC proposes requiring a person or company to obtain a license from the Commissioner of Health certifying that they are able to perform work on wells in a manner that is "protective of public health and groundwater." Iron Range Comment: As presented, this is a vague and broad requirement. Further, requiring persons or companies to secure such a permit through a separate agency imposes regulatory hurdles to operating in Minnesota.	Gas_wells	Contractor licensing

221	Iron Range proposes establishing clear criteria for the "plugging and abandonment of a well" that meets established requirements. New Mexico has a robust regulatory framework for plugging and abandonment of gas wells, including timelines for when non-producing wells must be temporarily abandoned and for which wells are allowed to be deemed "inactive." Texas has established a process whereby gas operators must inform the Texas Railroad Commission, surface owners, and others prior to beginning plugging operations. Texas is also required to submit specific forms with detailed information pertaining to the plugging activity. All wells must be "plugged to ensure that all formations bearing usable quality water, oil, gas, or geothermal resources are protected."	Gas_wells	Well construction
222	In MDH-4, GTAC proposes requiring the submission of a gas well construction notice and fee for each proposed gas well to the Commissioner of Health. Iron Range Comment: Iron Range recognizes the importance of ensuring that human health and water resources are protected. However, Iron Range is unclear whether this proposal provides the most efficient path to ensuring that these concerns are addressed. Iron Range proposes that the DNR and the Department of Health jointly agree on requirements for protecting human health and water resources that are subsequently enforced by the DNR. The Department of Health will then be able to assure itself that all wells approved and permitted by the DNR meet its required standards. This will also ensure that persons and companies are not required to obtain approval from multiple agencies as part of the gas development process.	Gas_wells	Well construction
223	In MDH-5, GTAC proposes requiring persons and companies to allow officials from the Health Department to access gas sites. Iron Range Comment: Generally, Iron Range agrees that authorized officials should be able to obtain access to gas well-sites, provided that the operator is given advance notice (except in cases of emergency).	Gas_wells	Well inspection
224	Iron Range recommends that the DNR be charged with ensuring that gas developments meet the health and safety requirements of the Department of Health so that a single agency, the DNR, is responsible for ensuring that those requirements are met.	Gas_wells	Well construction
225	In MDH-6, GTAC proposes requiring notifications to the Commissioners of Health, DNR, and Pollution Control of an occurrence during a construction or sealing of a gas well that has potential for significant adverse public health or environmental effect. Iron Range Comment: Generally, Iron Range supports this recommendation. However, Iron Range recommends establishing a clear mechanism for providing such notification, such as a 24/7 hotline. Further, GTAC should establish rules based on established gas industry practices for addressing particular and known events requiring immediate action by gas operators, e.g., dealing with blowouts, leaks, spills, etc.	Gas_wells	Notifications
226	In MDH-7, GTC proposes preventing gas well operators from injecting surface or groundwater or any other liquid, gas or chemical for purposes of disposal. Iron Range Comment: Iron Range believes that this requirement may not be sufficiently precise in terms of regulating the disposal of gas development waste products. Accordingly, Iron Range recommends at least developing a process whereby gas operators may obtain authority for the disposal of the waste products derived from such operations to ensure that they are disposed of properly, safely, and consistently with established gas development practices.	Gas_wells	Well construction
227	In MDH-8, GTAC proposes prohibiting person from hydraulicly fracturing wells. Iron Range Comment: This prohibition significantly impacts and likely completely disables the ability of operators to develop gas resources, including helium resources. Hydraulic fracturing enables operators to more efficiently produce gas by releasing gas that is trapped in geologic structures. Accordingly, Iron Range urges that GTAC authorize hydraulic fracturing but require that it be performed according to established practices that ensure safety to human health and water resources.	Health_and_environmental_quality	Hydraulic fracturing
228	In MDH-9, GTAC proposes that drilling fluids, cuttings, treatment chemicals, and discharge water be disposed of in accordance with state, federal, and local requirements. Iron Range Comment: Generally, Iron Range supports requirements for the disposal of the aforementioned waste products and encourages GTAC to adopt best practice requirements utilized in other jurisdictions. Accordingly, Iron Range provides the following examples for reference. (examples from NM, TX, ND, CO)	Gas_wells	Well construction
229	In MDH-10, GTAC proposes that drilling fluids used during the construction of gas wells be water or air based and additives must meet the requirements of the American National Standard Institute and National Sanitary Foundation standard 60. Iron Range Comment: Drilling fluids are selected based on the geology of the formation, well depth, and specific operational needs. Restricting fluids to water or air-based systems will not provide sufficient flexibility for challenging formations where other types of drilling fluids (e.g., oil-based or synthetic-based muds) are required for managing stability, pressure, and other conditions. This could directly lead to well bore integrity issues such as wellbore collapse, fluid loss into the formation, or inability to maintain well control.	Gas_wells	Well construction
230	MDH-11, MDH-12, MHD-13, MDH-14, and MDH-15: In MDH-11-15, GTAC proposes that gas wells be constructed to meet casing and grout requirements and that there be a physical separation of gas wells from residential buildings, water supply wells, schools, childcare centers, and that groundwater is protected during construction and sealing of gas wells. Iron Range Comment: Iron Range generally supports well construction in a manner ensuring the protection of groundwater resources and other sensitive sites in the vicinity of gas operations. Other jurisdictions have developed detailed requirements ensuring such protections. Iron Range encourages GTAC to evaluate these construction requirements to ensure that gas wells, on a case-by-case basis, are constructed in a manner that ensures groundwater protection during all phases of gas development, production and closure. Iron Range also supports the submission of a notification confirming that a well has been certified by the DNR as having been properly sealed, i.e., plugged and abandoned.	Gas_wells	Well construction
231	In DNR-15, GTAC proposes modeling financial assurances on those required for metallic mining operations. Iron Range Comment: As gas operations have progressed in sophistication, the costs associated with development have increased. Other states have established bonding requirements to ensure that the costs associated with plugging and abandoning gas wells, including surface reclamation, are in place prior to allowing operators to produce wells. Iron Range agrees that such financial assurance requirements are necessary not just for the initial operator, but also for subsequent operators acquiring wells. Iron Range encourages a framework for individual well bonding and statewide bonding covering all of an operator's gas activities. Iron Range provides the following examples in other jurisdictions as examples to consider when establishing Minnesota's financial assurance requirements.	Financial_assurance	FA structure
232	In DNR-9, GTAC recommends the same setback requirements for gas development projects as nonferrous mining projects. Iron Range Comment: Setbacks for gas operations are wholly different from those required by mining operations. Iron Range recommends that GTAC establish setback parameters appropriate for gas development because gas development operations and any associated potential risks are markedly different from the potential risks from mining development.	Environmental_review	Siting and setbacks
233	Setbacks should be required based upon the particular circumstances at each gas well location, e.g., when there are particularly sensitive areas such as animal habitats, schools, hospitals, and water supplies, etc. Imposing strict setback requirements can result in stranded gas deposits and lead to inefficiencies in gas production.	Gas_wells	Well setbacks

234	In DNR-10, GTAC proposes annual reporting requirements that are modeled after nonferrous mining projects and that these requirements sunset once annual reporting rules specific to gas resource development are promulgated. Iron Range Comment: Iron Range is generally supportive of annually reporting its production and other details, provided its proprietary information (information that if divulged publicly would place operators at a competitive disadvantage) is not disclosed. Iron Range recommends that GTAC develop clear and specific information that it wishes to obtain from operators so that preparations for gathering this information may be put in place.	Data_sharing_public_data	Company proprietary data
235	In DNR-11, GTAC proposes reporting to state regulators. Iron Range Comment: GTAC should specify what information it seeks to obtain and identify what it hopes to achieve when such information is received. GTAC should also be mindful of the burden that certain types of reporting requires, e.g., third-party auditing. Because gas operations are significantly different from mining operations, GTAC should clearly identify the information it hopes to obtain and specify its intended use so that operators can plan accordingly. Further, GTAC should enable certain types of information to remain confidential so that operators required to report certain types of information are not forced to divulge trade secret information or other information that could impact their respective competitive advantages.	Data_sharing_public_data	Company proprietary data
236	GTAC correctly identifies that Minnesota lacks the historical data typically derived from well-established reservoirs that other regions use to make reliable pre-drilling estimates. This creates challenges in determining the size, shape, and productivity of gas reservoirs. However, the absence of mature fields means operators are inherently in an exploratory phase, and it is unrealistic to expect the same level of data completeness or certainty as would be available in mature fields. Accurate spacing and pooling are critical to prevent resource waste and unnecessary drainage. Establishing or modifying rules pertaining to spacing and pooled units need to align with the feasibility of obtaining relevant data at various stages of development. Exploration wells often yield preliminary data insufficient to fully define the production zones that must be thoroughly understood to properly establish these rules.	Spacing_unit	General
237	Requiring pump test data before commercial production will hinder exploratory efforts, especially when commercial viability is still uncertain. While the pre-production report requirement serves a legitimate purpose, the inclusion of pump test data as a universal requirement is not practical for wells that do not yield measurable fluid or gas flows during exploration. Iron Range recommends that the rules are drafted to recognize the inherent uncertainty associated with the exploratory phase of gas development, and specify that pump test data and similar production-level information should only be required for wells that demonstrate characteristics indicating commercial viability.	Spacing_unit	General
238	In DNR-18, GTAC recommends that the correlative rights of the owners of a shared gas resource should be protected. Iron Range Comment: Generally, Iron Range supports the protection of correlative rights. Any statutory authority addressing pooling and spacing units needs to accommodate the unique needs of exploratory operations. Operators need flexibility to test formations, delineate resources, and establish the economic viability of a project before formalizing pooling arrangements or spacing units. While protecting correlative rights is important, statutory language needs to ensure that it does not unintentionally restrict the ability of operators to develop resources efficiently. That is, the language should not impose excessive restrictions on well placement with aggressive density and spacing limitations/requirements, which are critical for facilitating exploration.	Correlative_rights	General
239	In DNR-19, DNR-20, and DNR-23, GTAC recommends that the DNR commissioner be given statutory authority to establish or modify spacing units, to establish a process for operator proposed units, and to establish a process and procedure for owners of unleased mineral interests within a spacing unit to challenge the pooling orders. Iron Range Comment: Iron Range agrees that the DNR commissioner, or alternatively, its designee, such as a commissioner appointed hearing examiner, should have the authority to establish and modify spacing units, establish a process for operator proposed units, and for unleased mineral interests to challenge pooling orders. Iron Range notes that establishing and modifying spacing units requires the presentation of technical information.	Pooling_orders	Legal challenge process
240	Any person with authority to establish or modify spacing units should have access to persons with the requisite technical expertise to facilitate reasonable and prudent spacing unit establishment.	Spacing_unit	Size and shape
241	Typically, gas wells have spacing units established by the number of feet from lease lines within quarter sections as recognized under the Public Lands Survey System.	Spacing_unit	Property line setbacks
242	Iron Range encourages GTAC and the DNR Commissioner to establish clear rules and guidelines for the establishment of spacing units, a process for assessing proposals from operators, and for unleased mineral interest owners, et al, to challenge those proposals. However, challenges should be made as part of the application process and not after pooling and spacing orders are approved. This will ensure regulatory efficiency while providing interested parties with a voice in the outcome of regulatory proceedings where their interests are at issue.	Spacing_unit	Legal challenge process
243	Finally, Iron Range encourages GTAC to establish formal timing requirements and process procedures so that operators can schedule their development plans.	Spacing_unit	Application process
244	In DNR-21, GTAC proposes that landowners should be recognized in statute with the right to voluntarily pool their mineral interests for the joint development of shared gas. Iron Range Comment: Iron Range agrees that these rights of private landowners should be recognized; however, it is unclear that a statutory recognition is necessary for landowner's private property rights to be recognized. Iron Range believes that this recognition already exits. However, a statutory process for the exercising these rights would be prudent to establish.	Pooling_orders	General
245	**Iron Range encourages GTAC to expressly state that any changes made to this provision do not allow a lessor to assert any right to be pooled on an adjacent lease.**	Pooling_orders	General
246	In DNR-22, GTAC proposes that persons securing at least fifty percent of the mineral interests within a spacing unit be allowed to apply to the DNR Commissioner for a pooling order combining all of the mineral interests within a spacing unit, to issue pooling orders, and to recommend fees for involuntary pooling order applications. Generally, Iron Range supports this proposal.	Pooling_orders	% of owner consent
247	**(Fees for pooling order applications)** should be clearly established and operators should be allowed to recover their development expenditures before any payments are made to mineral interest owners who do not voluntarily participate in the development. (editor: instead of nonconsenting owners getting a 18 3/4% portion of their proportionate share of monthly revenue right from the start, and consenting owners recouping expenses from the other 82%).	Pooling_orders	Compensation for nonconsenting owners
248	In DNR-24, GTAC proposes that a gas well should not be drilled before a pooling order issued. A pooling order should not be required if an operator (Lessee) has secured 100% of the mineral interest inside a tract where spacing and density requirements can be met.	Pooling_orders	General
249	In DNR-25, GTAC proposes the adoption of statutory language describing how pooled mineral interests are managed during gas development operations and how the correlative interests of nonconsenting mineral interest owners are protected to ensure that they receive a proportionate share of the profits from a gas resource development project. Iron Range Comment: Generally, Iron Range agrees, and proposes that a statutory royalty of 1/8 be established for any mineral interest force pooled.	Pooling_orders	Rights of nonconsenting owners
250	Iron Range encourages GTAC and the State of Minnesota to carefully examine how gas production is regulated, reported, and executed in other jurisdictions. The "reasonably prudent operator" standard is a well-established principle in gas jurisprudence. This standard should be adopted and recognized to provide clarity to operators in Minnesota.	Process	General

251	In DNR-26, GTAC proposes the development of statutory language setting the requirements for the management of pooled mineral interests and describing the rights and responsibilities of the operators within a spacing unit to protect correlative rights of consenting and nonconsenting mineral interest owners. Further, GTAC proposes that operators applying for a pooling order to present evidence that they have made reasonable efforts, in good faith, to lease all of the mineral interests in a spacing unit. Iron Range Comment: Generally, Iron Range agrees with this proposal. However, these requirements must be clearly developed and implemented. Other jurisdictions have well- established processes that achieve the objectives that GTAC proposes. Iron Range encourages GTAC to carefully examine these requirements and develop Minnesota's requirements in a corresponding manner.	Pooling_orders	General
252	In DNR-27, GTAC proposes that operators provide monthly statements to nonconsenting landowners of all costs incurred, together with the amount of gas produced and the proceeds realized. Iron Range Comment: Generally, Iron Range supports this proposal. However, often, the expenses incurred after production is not known with complete accuracy for a number of months. Accordingly, Iron Range encourages GTAC to adopt reporting requirements that reflect the practicalities of the industry and allow operators to report expense and production statements within 90 days following the end of a particular calendar month.	Pooling_orders	Rights of nonconsenting owners
253	In DNR-28, GTAC proposes that unleased mineral interests tied to federal or tribal lands be "shielded" from pooling orders. Iron Range Comment: Generally, Iron Range recognizes that tribes are sovereign nations, with their own rules and regulations for development on tribal lands. Further, the federal government has robust gas regulations governing gas development on federal lands. Many states have well-established arrangements for working with tribes and the federal government. Iron Range recommends that GTAC and the State of Minnesota abide by already established federal and tribal regulations that contemplate the development of fee, state, federal, and tribal lands. In other jurisdictions, gas operators whose operation implicate or affect federal or tribals lands, must submit all materials submitted to the regulatory to the affected federal or tribal entity.	Pooling_orders	Shielding from pooling orders
254	In DNR-29, GTAC proposes that commercial extraction of gas resources be prohibited on forfeited severed mineral interests. Iron Range Comment: Determining ownership of the mineral estate is a complex and time consuming endeavor. The passage of time, death, conveyance, probate issues, etc., can impact the ability to determine mineral ownership with 100% certainty. Iron Range encourages GTAC to recognize this complexity and in lieu of prohibiting gas development, operators should instead at minimum hold the amount yielded from production in escrow pending final determination of ownership.	Pooling_orders	General
255	In DOR-1, GTAC proposes incorporating gas and oil into Minnesota's existing Occupation Tax, which currently applies to all mining companies, in place of a corporate income tax. Iron Range Comment: Broadly, Iron Range recommends that GTAC assess its current tax code to develop a comprehensive tax structure that balances the public interest with encouraging and facilitating gas development in Minnesota. Iron Range further encourages GTAC to evaluate how other jurisdictions assess taxes on gas production.	Tax_distribution	General
256	In DNR-12, GTAC proposes that operators applying for permits be assessed fees to cover the costs associated with environmental reviews. Iron Range Comments: It is unclear what sort of environmental review is required. Further, there are various types of environmental reviews, many of which do not apply to gas development projects. Iron Range urges GTAC to clearly establish an environmental assessment worksheet that pertains specifically to gas development so that operators can determine the type of environmental information they must obtain and submit.	Environmental_review	Need to define mandatory category thresholds
257	Iron Range notes that the $50,000 application fee already required under DNR-7 is intended to cover permitting. Any additional Environmental Assessment Worksheet (EAW) costs be integrated into the existing application fee to streamline the process and provide cost predictability for operators. A consolidated fee structure reduces redundancy and ensures that Minnesota remains competitive in attracting gas resource investment while maintaining environmental oversight. Alternatively, the $50,000 application fee should be credited toward the costs of preparing and reviewing the EAW. This ensures that operators are not paying twice for environmental review processes that are already accounted for in the permitting fee.	Gas_production_permitting	Permit fees too high
258	Establishing a robust, balanced framework tailored to the unique characteristics of gas development will be essential for Minnesota to ensure effective resource management, environmental protection, and economic growth. Our comments reflect a commitment to leveraging well-established practices from other jurisdictions while addressing Minnesota's specific needs. We urge GTAC to consider these recommendations to create a regulatory framework that promotes clarity, efficiency, and innovation while maintaining strong safeguards for public health, natural resources, and stakeholder interests.	Process	Robust regulation
259	Iron Range urges the State of Minnesota assess how other jurisdictions administer proceeds from gas development and establish a framework for utilizing those proceeds in a manner that achieves the state's financial objectives while also recognizing the associated costs inherent to gas development. Ideally, a balanced structure for proceeds should be developed based on the unique needs of gas operators	Revenue_generation	Need for economic analysis
260	Exploration and Production Waste. (Iron Range recommends referring to the waste described in this section as "gas field waste" to more accurately reflect its unique nature. Additionally, Iron Range encourages the development of tailored processes for gas operators to effectively manage and dispose of this specific type of waste. Many states have already implemented robust regulatory frameworks addressing oil and gas field waste management, which can serve as valuable references.	Process	General
261	Iron Range is of the position that the time to argue that a spacing order should be modified should be performed during a hearing on the application and not after the order has been established. A process to appeal an order establishing the order should be placed in the statute or rule, as evidenced in Subd. 6, below. However, allowing interested parties to apply for modifications to already approved spacing orders would impact gas development and production	Spacing_unit	Legal challenge process
262	Iron Range recommends that a process for informing tribes and/or the federal government be established for purposes of pooling federal and tribal lands instead of prohibiting those lands from being pooled	Pooling_orders	Shielding from pooling orders
263	(Input on whether pooled developement operations can take place on nonconsenting owner interests). Typically, the mineral estate is considered the dominant estate, meaning it has priority over the surface estate for activities necessary to develop the minerals. While surface owners are generally entitled to reasonable accommodation for their current use of the surface, completely denying access to the mineral estate alienates the mineral owner's property rights. This will result in legal challenges from mineral owners, as it will prevent them from developing their mineral resources.)	Pooling_orders	Rights of nonconsenting owners
264	(Nonconsenting owners share of drilling costs): (The language may diverge from standard gas practices, which typically limit nonconsenting owners' liabilities to specific cost categories or percentages). One hundred percent of the nonconsenting owner's share (it is unclear whether this refers to a fixed percentage or another metric and should be clarified) of the cost of surface equipment beyond the wellhead connections, including stock tanks, separators, treaters, pumping equipment, and piping (this equipment must be more particularly identified or else it is likely to lead to disputes)	Pooling_orders	Compensation for nonconsenting owners
265	The intent to charge the nonconsenting owner retroactively for costs as though they had agreed from the start may raise fairness concerns, especially if those costs were incurred without their input. The final statute should provide for a clear and fair mechanism to notify nonconsenting owners of their cost obligations before incurring significant expenses.	Pooling_orders	Compensation for nonconsenting owners

266	(G)as exploration is a nascent field in Minnesota, and the investment required for exploration that's necessary to unlock this resource may not be economically viable if the minimum royalty is set at 18.75%	Process	Leasing
267	Iron Range suggests calling "the owner's share of the estimated drilling and completion costs" within the "Good faith effort" section an "authorization for expenditure"	Process	General
268	On the topic of Contingency Reclamation Plans: It is unclear why this plan is a "contingency" plan. Iron Range recommends establishing a framework for site assessment to identify reclamation requirements when an gas operator proposes to plug and abandon a drill site and requirements for submission of a site reclamation plan (p.32)	Gas_wells	Well construction
269	On the topic of permit variance: "general welfare" should be defined but is also a broad/vague term (p.33)	Process	General
270	On the topic of development permit length: Granting a permit for a time to be determined by the commission could result in arbitrary time frames. Iron Range suggests that the permit be in place as long as gas is produced in paying quantities (p.34)	Gas_production_permitting	Permit length
271	On the topic of permit amendment fee: Iron Range recommends providing clarity as it is unclear if this is intended to refer to clause (1), or if this is meant to be 10% of $50,000 (p.34)	Gas_production_permitting	General
272	On the topic of cancelled development permits: "public interests" is vague and should be defined, or alternatively, should be changed, e.g., "public health, safety, and welfare").	Gas_production_permitting	General
273	On the topic of reclamation fees: This section appears to introduce what may be inaccurately labeled as a "reclamation fee," as no other mention of such a fee is made within the GTAC Recommendations. The fees described—$75,000 annually for producing wells and $37,500 annually for non-producing wells—are impractical and inconsistent with typical gas development practices. Gas development plans often involve significant time lapses between securing a lease and achieving production. During this pre-production period, operators frequently incur substantial costs for geophysical surveys, exploratory drilling, geological evaluations, and infrastructure development, all without assurance that production in paying quantities will occur. Given that initial wells in Minnesota will be exploratory, this high annual fee creates undue financial risk and will discourage operators from undertaking gas development projects altogether. Iron Range strongly urges GTAC to reconsider these proposed fees. We recommend implementing a substantially smaller fee structure, at least during the nascent stage of Minnesota's gas industry, until the feasibility and opportunities for production are more clearly established.	Gas_production_permitting	Reclamation fees
274	On the topic of reclamation fees: Additionally, Iron Range encourages GTAC to explore the use of "rental payments" as a more practical and industry-standard approach under these circumstances. Rental payments are commonly assessed during the pre-production phase of gas development and better reflect the financial realities and risks inherent in such operations. This adjustment would promote early investment in Minnesota's gas industry while maintaining reasonable safeguards for the state's interests.	Gas_production_permitting	Reclamation fees
275	On the topic of supplemental application fees: Due to the section heading titled "Supplemental application fee" it is unclear whether the fee described is intended as an initial application fee or a supplemental application fee. To ensure cost predictability for operators and transparency in Minnesota's fiscal policies, Iron Range recommends that the amount of this fee be explicitly established. Providing a clear and fixed fee structure will allow operators to accurately assess the financial implications of supplemental applications, encouraging responsible investment and development in the state.	Gas_production_permitting	Permit fee transparency
276	On the topic of written agreements to cover supplimental application fees: Entering into an agreement with terms that are not yet clearly established may introduce uncertainty for both parties. Iron Range suggests that the commissioner work collaboratively with the gas industry to develop clear and practical terms before these statutes or rules are finalized. Alternatively, a well-defined fee structure could be established upfront, allowing operators to assess the costs and make informed decisions about conducting business in Minnesota.	Gas_production_permitting	Permit fee transparency
277	On the topic of not issuing a permit until fees are paid: Clarification is needed on how the "unobligated balance" of the monitoring fee revenue will be tracked, monitored, and controlled throughout the construction process. Iron Range recommends that the commissioner establish a transparent accounting mechanism to ensure that fee revenues are allocated and managed appropriately. This could include periodic reporting to permit holders, outlining how fees are being utilized and specifying the remaining balance. Such a system would provide accountability and confidence to operators, ensuring that any unobligated funds are refunded promptly and accurately upon project completion.) (How will the "unobligated balance be monitored/controlled?	Gas_production_permitting	Permit fee transparency
278	On the topic of contested case hearings: affected persons should be carefully and clearly defined to prevent excessive petitions from persons only "affected" nominally by proposed development plans, e.g., person who have a visual line of sight to the proposed development. This will help prevent frivolous contests intended only to delay project development. Petitions should be granted to persons who demonstrate the potential to suffer material harm based on established criteria. PROPOSED REVISED LANGUAGE: Subdivision 1. Petition for contested case hearing. Any person owning property directly and materially affected by the proposed gas resource development operations or any federal, state, or local government having regulatory or operational responsibilities directly impacted by the proposed operations, as identified in the application for a gas resource development permit under section 93.5174, may file a petition with the commissioner to hold a contested case hearing on the completed application. To be considered by the commissioner, a petition must be submitted in writing, demonstrate specific harm or direct material impact resulting from the proposed development, and contain the information specified in subdivision 2. The petition must be submitted to the commissioner within 30 days after the application is deemed complete and filed. The commissioner may summarily dismiss petitions that do not meet the criteria for standing or fail to demonstrate direct material impact. In addition, the commissioner may, on the commissioner's own motion, order a contested case hearing on the completed application.	Process	Contested case and legal
279	On the topic of contested case hearing petition contents: This requirement seems appropriate for initiating a petition but may be overly burdensome if the petitioner lacks access to detailed information. It might be helpful to explicitly state that this statement can be based on the petitioner's best available knowledge at the time of filing, allowing for subsequent refinement as the process develops.	Process	Contested case and legal
280	(2) a statement of the issues proposed to be addressed by a contested case hearing and the specific relief requested or resolution of the matter. **IR:** (While useful for scoping the hearing, this presupposes that petitioners have sufficient understanding of the issues and possible resolutions, which may not be the case before discovery. Consider allowing petitioners to outline broad issues and refine them during the process.)	Process	Contested case and legal
281	(b) To the extent known by the petitioner, a petition for a contested case hearing may also include: (1) a proposed list of prospective witnesses to be called, including experts, with a brief description of the proposed testimony or a summary of evidence to be presented at a contested case hearing; **IR:** (This assumes petitioners already have access to witnesses and evidence before discovery, which is unrealistic in many cases. Consider revising this to allow petitioners to provide a preliminary indication of witnesses or testimony they may seek, subject to amendment as the process unfolds.)	Process	Contested case and legal
282	(2) a proposed list of publications, references, or studies to be introduced and relied upon at a contested case hearing; and **IR:** (As with the witness requirement, this presupposes access to materials that may only be identified during discovery. Consider clarifying that this list can be preliminary and subject to supplementation as the hearing progresses.)	Process	Contested case and legal

283	(3) an estimate of time required for the petitioner to present the matter at a contested case hearing. **IR:** (Requiring this estimate at the petition stage may lead to inaccurate or speculative responses. Consider removing this requirement or explicitly stating that it is a non-binding preliminary estimate or perhaps hold a scheduling hearing later in the process.)	Process	Contested case and legal
284	(c) A petitioner is not bound or limited to the witnesses, materials, or estimated time identified in the petition if the requested contested case is granted by the commissioner. **IR:** (This is a helpful provision, but it may be worth clarifying that petitioners can freely update their submissions as new information arises, particularly following discovery. This would reinforce the flexibility already implied.)	Process	Contested case and legal
285	Subd. 3.Commissioner's decision to hold hearing. (a) The commissioner must grant the petition to hold a contested case hearing or order upon the commissioner's own motion that a contested case hearing be held if the commissioner finds that: **IR:** (This standard is appropriate but may benefit from further explanation of what constitutes a "material issue of fact." Consider including examples or criteria to help guide commissioners and petitioners, such as factual disagreements with the potential to impact the permit's approval or conditions.)	Process	Contested case and legal
286	Section 18. 93.5177 ENVIRONMENTAL REVIEW FEES. **IR:** (Environmental reviews are situation dependent, with the circumstances for each project determining the type of environmental reviews that are necessary for a particular situation. Iron Range recommends the development of a flexible approach to environmental reviews. Operators should also have the ability to hire certified professional environmental consultants to submit information to the commissioner in lieu of placing the responsibility of all aspects of environmental reviews on DNR staff) p41.	Environmental_review	General
287	Requirement for reclamation cost estimate...(5) A person intending to develop gas resources shall submit, as part of an application for a gas resource development permit, a documented estimate of costs necessary for the reclamation or restoration **IR:** (This requirement would be more appropriately established following an inspection of the site as the project nears the end of its life, to ensure the estimate accurately reflects the conditions and necessary reclamation or restoration activities at that time. However, financial assurances should still be required at the outset of the project to safeguard against the risk of an operator being unable to meet its obligations in the future. This dual approach ensures both accurate reclamation cost estimation and adequate financial protection for the state.) PROPOSED REVISION: If a corrective action is required during the implementation of the gas resource development plan to minimize waste or protect human health or the environment, the permittee shall submit to the commissioner a cost estimate for completing the required actions, based on the scope and nature of the corrective action. The cost estimate must be prepared using reasonable industry standards and practices. The commissioner shall provide clear guidelines and templates outlining the required elements and procedures for submitting corrective action cost estimates. These guidelines should ensure that cost estimates are proportional to the corrective action's complexity and potential impact. p42.	Gas_production_permitting	Reclamation fees
288	(7) The commissioner shall evaluate submitted cost estimates and cost estimate adjustments using individuals with documented experience in material handling and the reclamation or restoration of oil and gas locations. The applicant must pay the costs incurred by the commissioner to hire third parties to perform this evaluation. **IR:** (Requiring applicants to cover the costs of third-party evaluations creates financial uncertainty, as these costs could vary widely and be difficult to predict. This unpredictability could deter both investment and project development. Iron Range recommends establishing a fixed fee or capped cost structure for third-party evaluations to provide cost certainty for applicants. Additionally, Iron Range understands that the $75k proposed annual fee is intended to cover staff costs. If operators must incur additional costs from third-parties, then the $75k fee is duplicative. Iron Range recommends clarifying the circumstances under which third-party evaluations are necessary, such as when the complexity of a project exceeds the expertise available in-house with the DNR. Alternatively, allocating a portion of the $75k fee to cover third-party evaluations when needed would be prudent).	Gas_production_permitting	Permit fee transparency
289	(8) Financial assurance in the amount equal to the contingency reclamation cost **IR:** ("contingency reclamation cost" must be defined)	Financial_assurance	FA structure
290	(11) The permittee must ensure that the provider of financial assurance gives the commissioner 120 days' notice prior to cancellation of the financial assurance mechanism. Upon receipt of this notice, the commissioner shall initiate a proceeding **IR:** (the DNR should consider having a DNR staff member initiate contact with a permittee in lieu of initiating a proceeding) to access the financial assurance.	Financial_assurance	FA structure
291	(13) Financial assurance must be made available to the commissioner when the operator is not in compliance with either a contingency reclamation plan or corrective action plan. **IR:** (This provision seems ineffective and redundant because financial assurance is already required under this proposed framework. In other words, whether an operator is compliant or noncompliant, financial assurance should already be in place.)	Financial_assurance	FA structure
292	(14) The commissioner may deny, suspend, revoke or modify a gas resource development permit or assess civil penalties **IR:** (A schedule of fees for violations should be established) if the permittee fails to comply with any portion of this part.	Process	Contested case and legal
293	Any person aggrieved by any final order, ruling, or decision of the commissioner may obtain judicial **IR:** (A particular court should be identified) review of such order, ruling, or decision under sections 14.63 to 14.69.	Process	Contested case and legal
294	Subdivision 1. Civil penalty. If any person fails to comply with any provision of sections 93.5171 to 93.51780, or any rules promulgated pursuant to these sections, or any permit condition required by these sections or the rules, for a period of 15 days **IR:** (various factors can impact an operator's ability to address certain actions within a 15-day period. Iron Range recommends incorporating flexibility by tolling the aggregation of penalties in cases where corrective actions are delayed due to circumstances beyond the operator's control, such as supply chain issues or the unavailability of necessary parts.)	Process	Contested case and legal
295	103I.001 LEGISLATIVE INTENT. This chapter is intended to protect the health, safety, and general welfare by providing a means for the development and protection of the natural resources of and groundwater in an orderly, healthful, and reasonable manner.103I.005 **IR:** PROPOSED REVISION: This chapter aims to safeguard public health, safety, and general welfare by establishing a framework for the responsible and sustainable development, use, and protection of natural resources and groundwater in an orderly and environmentally sound manner. p44.	Environmental_review	Environmental impacts
296	Subd. 9. Exploratory boring. **IR:** (This section is largely inapplicable to gas development)"Exploratory boring" means a surface drilling done to explore or prospect for oil, natural gas, apatite, diamonds, graphite, gemstones, kaolin clay, and metallic minerals, including iron, copper, zinc, lead, gold, silver, titanium, vanadium, nickel, cadmium, molybdenum, chromium, manganese, cobalt, zirconium, beryllium, thorium, uranium, aluminum, platinum, palladium, radium, tantalum, tin, and niobium., and a drilling or boring for petroleum.	Gas_wells	Exploratory borings
297	Subd. 2. Fees. (a) A person must meet the gas well contractor license requirements and fee requirements to construct, repair, or seal a gas well. The fee for a gas well contractor license is $350.00. The fee for a gas well contractor license renewal is $350.00. **IR:** (This fee structure appears more aligned with mining activities rather than gas operations, particularly for professionals engaged in plugging and abandonment tasks. Iron Range recommends revising the fee to better reflect industry practices and the specialized nature of gas plugging operations, ensuring it is both reasonable and appropriate for the sector.) p45.	Gas_wells	Contractor licensing
298	(b) A gas well contractor must designate a certified representative. The certified representative must meet the application and fee requirements. The application fee is $125.00. The renewal fee is $125.00. **IR:** (It is unclear what specific certification the representative must hold, the qualifications required, or the process by which the representative is designated as certified. Clarifying these details, including the certifying authority, eligibility criteria, and any necessary training or experience, would ensure transparency and help contractors comply effectively.)	Gas_wells	Contractor licensing

299	(c)A person must meet the registration and fee requirements for rigs used to construct, repair, service, or seal a gas well. The fee to register gas well rigs is $125.00. The fee to renew rig registration is $125.00. **IR:** (It is unclear why rig registration is necessary for these activities and how the registration process will be administered. Additionally, there is no explanation of what information must be provided during registration, how frequently rigs need to be renewed, or whether the fee is proportionate to the administrative costs incurred by the state. It is also unclear how often registration and renewals are required. Providing clarity on these aspects would help ensure the requirement is reasonable and justified.)	Gas_wells	Well construction
300	(f)A person must submit a notification for sealing a gas well on a form prescribed by the commissioner, with the fee of $50,000. **IR:** (It is unclear why this fee in this amount is necessary. Iron Range recommends placing any and all fee requirements in the fee section of this statute)	Gas_wells	Notifications
301	Subd. 3. Rig registration. (a) Rigs used to drill, maintain, repair, or seal a gas well, including drilling rigs and workover rigs, must be registered with the commissioner. **IR:** (Iron Range recommends consolidating the rig registration and contractor licensing requirements into a single streamlined process. For example, a single license could cover both the rig and the contractor's operations, reducing redundancy. Further, clear definitions of terms like "rigs used to maintain" and "gas well contractor" should be established to ensure operators understand who and what is subject to these requirements. Finally, aligning these requirements with existing gas industry standards, such as those used in other jurisdictions, to avoid imposing unique state- specific burdens that could deter investment, is recommended).	Gas_wells	Contractor licensing
302	Subd. 4. Gas Well Contractor's License. (a) A person must not construct, repair, or seal a gas well, without a gas well contractor's license issued by the commissioner. **IR:** (The requirement for a gas well contractor license seems inconsistent with standard gas industry practices. It is not a universal gas industry term and seems more consistent with water well practices)	Gas_wells	Contractor licensing
303	(c)The commissioner of natural resources may require a bond, security, or other assurance from a gas well contractor if the commissioner of natural resources has reasonable doubts **IR:** (This is a vague and subjective requirement) about the person's financial ability (this should be covered by the operator's financial assurances) to comply with requirements of law relating to reclamation of a...	Financial_assurance	FA structure
304	ii.a stratum of clay, sandy clay, or silty clay ten feet or more in vertical thickness, as defined in the Soil Survey Manual, incorporated by reference in United States Bureau of Plant Industry, Soils and Agricultural Engineering, Soil Survey Manual, United States Department of Agriculture Handbook, no. 18 (1951), pages 205 to 213.; or **IR:** (Iron Range recommends utilizing guidance documents applicable to gas development utilizing petroleum engineering and petroleum geology standard practices) p48.	Process	General
305	Subd. 5. Hydraulic fracturing treatment. Hydraulic fracturing treatment is prohibited in a gas well. **IR:** (Iron Range strongly urges GTAC to remove this restriction and implement regulations that authorize hydraulic fracturing using established practices that ensure safety to human health and water resources.) p49.	Health_and_environmental_quality	Hydraulic fracturing
306	103I.708. OIL WELLS. A person shall not explore, prospect, or construct an oil well until an environmental review has been completed and a production permit has been obtained from the commissioner of natural resources. **IR:** (Iron Range recommends the development of a statutory framework that contemplates oil and gas development) p52.	Process	Robust regulation
307	116D.04 ENVIRONMENTAL IMPACT STATEMENTS **IR:** (Iron Range recommends titling this section "Environmental Assessment Worksheets" instead of "Environmental Impact Statements," which are a particular form of environmental assessment) p52.	Environmental_review	General
308	Section . Minnesota Statutes 2024, section 289A.02, subdivision 6 is amended to read: Subd. 6. Mining company. "Mining company" means a person engaged in the business of mining or producing ores, minerals, metals, gas, or oil in Minnesota subject to the taxes imposed by section 298.01 or 298.015. **IR:** (Iron Range urges GTAC to differentiate between mining companies and oil and gas companies. The development of oil and gas differs significantly from mining projects. Oil and gas development projects employ specialized practices that are distinct from those used in mining, and merit specific practical regulatory frameworks that acknowledge and address these differences.) p53-54.	Gas_production_permitting	Mine permitting not best model for gas permitting
309	Iron Range Exploration provided three pages of example definitions in Appendix I of their input letter, with citations. Most appear to be based on New Mexico law.	Process	General
310	We commend the members of the Gas Resources Technical Advisory Committee ("GTAC") on their draft recommendations and statutory language to create a temporary framework to regulate development of gas resources like hydrogen or helium in Minnesota and look forward to working with the agencies, lawmakers and others to create the new temporary framework in law during the 2025 legislative session.	Process	General
311	Our comments on the GTAC recommendations focus on exploration and appraisal activities to be regulated by the Minnesota Department of Health ("MDH") and the proposed regulatory framework for gas production facility activities from the Minnesota Department of Natural Resources ("DNR"), the Minnesota Pollution Control Agency ("MPCA") and the Minnesota Environmental Quality Board ("EQB"). For those provisions, we generally comment that the final temporary framework conforms as closely as possible to similar provisions in existing law and rules applicable to mineral exploration and to mineral mining activities.	Process	General
312	In a perfect world the creation of a gas regulatory system would allow for thoughtful exploration and development that span several decades, as more is learned about this potentially important resource. We hope that the GTAC agencies and the legislature will keep that in mind as it creates a temporary regulatory framework for this new industry.	Process	General
313	Our comments are, by necessity, general ones for the GTAC to consider when revising recommendations to be submitted to the legislature by January 15, 2025, given the short time we have had to review the recommendations.	Process	General
314	It is true that Minnesota currently lacks a comprehensive regulatory framework for permitting gas resource development projects. Borings for gas exploration have subtle but important differences from hard rock mineral exploration borings and water wells. Accounting for gas resource ownership has complications that do not exist for mineral mining. But it is also true that state and federal regulations already provide robust regulation for many critical gas activities.	Gas_production_permitting	Mine permitting not best model for gas permitting
315	Our exploration activity procedures show that gas exploration projects can proceed under existing regulation. With a basic understanding of the project purpose and the methods available to satisfy that purpose, we identified the applicable laws and regulations that would apply to the project. We identified site layouts to avoid and minimize environmental effects by considering public and private land ownership, zoning for appropriate land/special use and transportation permits, seasonal timing of work (accounting for frozen conditions and spring road restrictions), delineated wetlands and implemented common industry mitigation measures (e.g. use of construction mats, reducing site footprint, shifting site layout, use of best management practices for erosion control). All those measures were implemented under the existing regulatory programs.	Process	General
316	Our exploratory boring activity was done under MDH regulation and direct supervision of MDH staff. The installation of exploration borings is a regulated activity and we worked within the laws and rules in place at the local, state, and federal level to protect public health, safety, and the environment.	Gas_wells	Exploratory borings

317	MDH regulates the construction and sealing of exploratory borings under Minnesota Statutes, chapter 103I and Minnesota Rules Chapter 4727 and has over 40 years of experience regulating hundreds of Minnesota exploratory borings. They have the administrative and technical processes in place to ensure that our activities are conducted in a way that protects public health, safety, and the environment. We support the MDH revision of their rules to make them more specific to gas related activities. Their existing program for exploratory boring programs is an important foundation for that work.	Gas_wells	Exploratory borings
318	We begin our comments with this background to emphasize that regulatory oversight exists for gas exploration activities in Minnesota. We ask that the GTAC agencies and the legislature ensure that the temporary regulatory framework in statute and the final framework in rules are carefully crafted to maintain and enhance the efficiency of the current exploration regulatory process.	Process	Robust regulation
319	Minnesota regulation for gas exploration should encourage mineral owners and explorers to fully investigate a potential resource and assess the economic viability of a project. Pulsar suggests that the GTAC recommendations be closely reviewed and revised as necessary to create rules for gas exploration similar to MDH's well-established rules for construction and closure of exploratory borings, including existing exploratory borings for mineral exploration. The Minnesota Department of Health is currently the primarily responsible regulator for that activity and the 2024 legislation confirms that MDH will have that role for gas projects.	Gas_wells	Regulatory oversight
320	The Minnesota Department of Health ("MDH") has a well-developed program for the regulation of explorers and exploration drilling. That includes licensing of explorers, certification of responsible individuals, registration of drilling machines and hoists and notification, construction and use of exploratory borings. A very large number of metallic mineral exploratory borigs have been constructed in Minnesota under that regulatory authority, including our Jetstream #1 well. Pulsar recommends that the temporary regulatory structure utilize that same regulatory structure, acknowledging that the MDH needs to adopt rules addressing the unique characteristics of gas wells.	Gas_wells	Regulatory oversight
321	Our hope, which we believe many share, is that the temporary framework adopted by the 2025 legislature provides MDH for a solid structure that allows them to quickly proceed with rulemaking to create a permanent regulatory structure in rule.	Process	General
322	Using the existing approach is appropriate because exploration for helium serves the same purpose as exploration for metallic minerals – undertaking the work needed after a resource is discovered to develop enough information to propose a viable project to produce a product to market. An apt template is the Minnesota DNR's description of the steps for moving "from exploration to development" for a nonferrous project.6 Regulation should follow accordingly.	Gas_wells	Exploratory borings
323	MDH will of course need to modify its regulations to account for the differences between hard rock mineral exploration and gas exploration. A variety of types of wells will be drilled for gas exploration. Some exploratory wells will be constructed solely to look for and understand a gas deposit, acquiring core and wireline data and subsequently being permanently sealed similar to non-ferrous and ferrous exploratory borings. Others will necessarily be constructed to allow for collection of data on flow rate, pressure and other parameters to further the understanding of the potential for commercial gas production from a resource. Those wells are required in the exploratory phase to gather data for a preliminary economic assessment and an economic feasibility study of the potential to create a viable gas production facility and how it will be designed. The MDH regulatory structure should allow proper regulation of all of them.	Gas_wells	Well construction
324	An exploratory well might also be used later for gas production. The transition of the use of a boring from exploration to production has little to do with the construction of the boring, but rather is accomplished by connecting flow lines and other equipment to gather the gas and transport it to the gas processing facility to produce a marketable product.	Gas_wells	Exploratory borings
325	One important topic is understanding how wells are constructed and used in the gas exploration and production processes. Globally accepted engineering standards for the construction and maintenance of gas wells already exist. These standards have been developed over decades of working with high pressured gases in a wide variety of both extreme and moderate conditions. We recommend that MDH adopt existing American Petroleum Institute ("API") and/or International Organization for Standardization ("ISO") standards which govern drilling practice, construction, and maintenance of gas wells. For example, a variance was approved by the MDH for the Jetstream #1 well to allow for the use of API standard 5CT casing in the construction of the Jetstream #1. The state regulators recognized that the standards of the casing required for Jetstream #1 were greater than that allowed by current rules and commendably they approved the variance allowing for a higher standard and more fit for purpose construction methodology.	Gas_wells	Well construction
326	In conclusion regarding exploration, we respectfully request that the next version of the GTAC recommendations to the legislature be revised to make clear that the MDH is responsible for regulating all wells related to gas exploration and production from construction to closure and that environmental review and permitting follow that important investigatory activity.	Gas_wells	Regulatory oversight
327	(E)nvironmental review and permitting (should) follow investigatory activity. The regulations should recognize that a gas well is not capable of production without a gas processing facility and associated gathering infrastructure, and it is not the design of the well that determines when a project has moved from exploration to production, but rather when those activities are being planned to gather and process gas for production.	Environmental_review	General
328	A key provision of the legislation passed last May stated that the DNR "may not grant a permit for the production of gas or oil unless the legislature approves a temporary permit framework that allows issuance of temporary permits." We urge the GTAC to work closely with the legislature, industry and others to finalize the temporary structure to regulate gas production in the 2025 session.	Process	General
329	Our first comment on the DNR's proposed regulatory framework addresses the recommendation that statutory language be struck requiring the DNR to write rules for the conversion of an exploratory boring to a production well. Pulsar does not oppose that suggestion and strongly agrees with the GTAC recommendation that MDH be given responsibility for well abandonment and for all gas wells irrespective of their identified purpose. We note, however, that it remains important for agencies, gas explorers and gas project proposers to have clear guidance when a project converts from exploration to production activities that require environmental review and permitting.	Gas_wells	Regulatory oversight
330	The DNR must in rules or guidance make clear that "production" begins when action is taking to extract gas for beneficiation and does not begin when a well intended for exploration and appraisal is constructed in a manner that may in the future facilitate its use for gas production.	Gas_production_permitting	When is a permit needed
331	The regulatory sequence of activities of exploration, environmental review and permitting for gas should follow the current regulatory sequence for those activities for metallic minerals. Environmental review and permit applications for gas production should occur when a project proposer has completed sufficient exploration and other analysis to have the information needed to define a proposed plan for a gas production facility. Only then will sufficient information be available about project locations, scale and technologies to facilitate environmental review. We respectfully suggest that the GTAC clarify that environmental review and permitting led by DNR start when a project proposer is ready to move from exploration to production activities.	Environmental_review	No mandatory EAW for exploration
332	Our next comments address GTAC recommendations regarding environmental review. We believe that a mandatory EAW for gas production facilities is unnecessary. Gas projects are likely to have a small footprint (much smaller than many other projects in Minnesota that do not require environmental review) and will construct wells using methods that are already regulated by a complete and mature MDH regulatory structure for exploration. The DNR is well prepared to regulate gas production given their expertise and experience regulating larger and more complex hard rock mining activities.	Environmental_review	No mandatory EAW for exploration

333	Pulsar does not oppose that mandatory environmental assessment worksheet requirement, however, if the legislature believes that environmental review is important under the temporary regulatory structure to gain public confidence in industry and agency actions.	Environmental_review	General
334	Pulsar does, however, strongly oppose the GTAC recommendation that environmental review be required in advance of exploration. Our comments above describe the basis for that position.	Environmental_review	No mandatory EAW for exploration
335	We also oppose the GTAC recommendation that the DNR assess a gas project proposer for EAW costs and environmental review cannot start until those costs are paid. That would be a requirement unique to the gas industry. For all other state agency environmental reviews, those requirements only apply to state agency preparation of an Environmental Impact Statement. Such a requirement would be a strong negative signal from the State of Minnesota to gas explorers, gas rights owners and the public that gas projects represent some sort of unique threat to the environment and that the state is imposing more costs and potential delays on gas projects than it imposes any other type of project in Minnesota to address those concerns. We respectfully request that the EAW process for gas projects follow existing processes and that the agencies refrain from sending this negative signal to interested parties.	Environmental_review	EAW and EIS costs
336	The DNR is making recommendations on pooling and spacing that are outside the legislative mandated issues the GTAC was to address. The concepts regarding those issues in the GTAC released for public comment on December 2, 2024 require more than three weeks to contemplate. We suggest that the GTAC and the legislature avoid any urgency to rush the process to develop detailed regulations on pooling, spacing and unitization before the needed information is available.	Process	General
337	Governing regulations should provide a clear path forward for the proponents of gas resource exploration and development projects to acquire permits within reasonable timeframes with clear expectations. It is in the state's best interest to allow for future discoveries and thorough evaluation of gas resources.	Process	General
338	It was clear during last year's legislative discussions that capture of gases and the proper allocation costs and benefits to owners is at the forefront of the need for the temporary and permanent regulatory frameworks. To ensure that correlative rights are protected, the state should consider creating state-wide rules for spacing units for gas wells until reservoir characterization reveals actual drainage. This is customary practice in states with multiple discoveries and development of varying mineral resources; where habitual development brings data to determine geographical areas of reservoir characteristics that lead to the creation of field rules for specific mineral extraction resources. For instance, in Colorado on the West Slope, mountainous region of the state operators develop predominantly dry gas wells, with little oil production, whereas in the Denver-Julesburg (DJ) Basin, which is a flat desert plane, the major mineral developed is oil with minimal gas output. For these instances field rules would be created to account for the difference in the resource (oil versus gas) as well as the proven drainage for such areas. All of this comes from years of scientific data that is collected and contemplated in more than one public hearing.	Spacing_unit	Size and shape
339	In most productive states, and until field wide rules can be established through science, states zoned with a township and range plane have statewide rules for gas spacing units are typically 160 acres more or less, or a governmental quarter. Field wide rules would be established with continual drilling, which will provide information on the reservoir drainage patterns. Operators and the state regulatory agency would review data to determine what reservoir depletion is exhibiting by drilling more wells and acquiring more data. One (1) vertical natural gas discovery well would typically be relegated to 160-acres or 320-acres until the reservoir depletion for a vertical well could be studied. In these instances, setbacks typically are anywhere from 330-feet or 660-feet from the drilling and spacing unit to protect correlative rights.	Spacing_unit	Size and shape
340	The DNR and legislature should consider proposing a 160-acre spacing unit for a vertical gas well with no less than 330-foot setbacks from the drilling and spacing unit for both the temporary and post-regulatory frameworks for gas development.	Spacing_unit	Property line setbacks
341	We also note that it is important to consider the perspectives of the Bureau of Land Management ("BLM") gas regulations given the location of federal mineral interests in northeast Minnesota. Due to federal regulatory implications it's important to be clear in regulation that state regulations only have jurisdiction over gas resource development for state and fee mineral estates.	Process	General
342	Finally, we encourage the agencies to review gas regulations from several states to consider temporary and long-term regulations for gas wells, allowing a balanced viewpoint of regulations for gas development. Minnesota is creating a framework for a new industry. The vast regulatory frameworks established by other states with decades-long production may not suit the needs of a Minnesota regulation of a nascent industry here. Some of those other states might be pursuing a policy of encouraging exploration and development and others might be moving to discourage gas exploration and production.	Process	Robust regulation
343	DNR's suggestion that gas drilling be prohibited until pooling orders are issued is both unreasonable and impractical. The suggestion is unreasonable if Minnesota wants to encourage gas exploration. It is impractical because drilling is needed to gather the information needed for pooling orders.	Pooling_orders	General
344	The regulations should instead provide that drilling can occur before a pooling or spacing order is approved but that the well cannot be used for production until a pooling or spacing order is approved. This is a customary practice in New Mexico and other states.	Pooling_orders	General
345	Allocating production equitably to mineral interest owners is the only matter at risk when determining pooling and spacing, therefore operators should be allowed to drill and construct wells for the purpose of exploration, which have considerable upfront costs. Scheduling rig and completion crews requires a delicate balance of several moving parts such as crew availability, weather and wildlife interactions. Also, several rig contracts financially penalize operators when the rig is "down" or not in use because that rig could be utilized elsewhere.	Pooling_orders	General
346	All parties understand the concern DNR might address by instead recommending a prohibition on gas production until a pooling order is issued. All parties should be concerned, however, in the time it will take in Minnesota to make decisions in the case of a pooling order dispute. We understand that in most states with gas development it can take anywhere from two(2) to four (4) months from the date the application for a hearing is submitted to the time of the actual hearing. In New Mexico, docket hearings typically occur within two (2) months, and in Colorado they typically occur within three (3) to four (4) months. Those timelines for hearing and resolution of disputes are very likely far shorter than would be expected under a typical contested case hearing process under Minnesota's Administrative Procedure Act.	Pooling_orders	Legal challenge process
347	The state should closely review the basis for fees on gas exploration and production activity that is not comparable to fees on other activities in Minnesota. For comparison, the application for a permit to drill a well from the BLM is $12,155. Legislative action on gas industry fees should include review of a detailed explanation for the total costs that are the basis of any fee.	Gas_production_permitting	Permit fees too high

348	Clarify that permits issued have a temporal term and set a maximum temporal term for permits. (T)he legislative language for gas permitting should require a term of a “fixed period of time covering a precise number of years.” Revising the language of 93.5174 subd. 4 to clarify this would avoid confusion about the meaning of the word “term.” In addition, as the Minnesota Supreme Court noted, this does not deprive the Minnesota Department of Natural Resources of the ability to enforce the law outside of the permit term. By requiring a term of, for example, 10 years, there would be a regular period for review of the effectiveness of permit conditions, and the chance to make revisions in response to changing circumstances. Comparable environmental permits issued by the Minnesota Pollution Control Agency, such as National Pollutant Discharge Elimination System water permits, have a term of five years. RECOMMENDATION: Insert “of ten years” or other fixed time after “term” in the proposed language for Minn. Stat. 93.481, subd. 4.	Gas_production_permitting	Permit length
349	(S)ince there is confusion elsewhere in regard to the permit conditions that would apply to a permittee who received a permit under the temporary framework (see item 5 below), it would be good to ensure that all permits issued under this section expire, and must be renewed. This is consistent with many other environmental permits, which also have fixed terms, expire, and must be renewed in a public process.	Gas_production_permitting	Temporary permits
350	The proposed legislation amends Minnesota Statutes 2024, section 298.015, subdivision 1 to set a tax rate for helium products and two other gas products that are left blank. It’s common practice for draft legislation to leave blank figures to be determined later. In this case, though, the tax rate for helium is of public interest, and the use of a blank placeholder here makes it impossible to comment on whether the proposed tax rate is fair. In addition, the two blank products below it are also items that should be available for the public to comment on before the legislation is introduced. RECOMMENDATION: Insert a specific number for the percentage of tax paid for helium and any other specific gas product, and make that available upon the revision of the proposed legislation and before the completion of the January 15th report to the Legislature.	Revenue_generation	Tax rates
351	3) Either delete or modify Declarations of Policy in the proposed legislation The proposed legislation contains several declarations of policy and statements of legislative intent. In my interactions with legislative staff over the last few years, I’ve been told that such declarations are discouraged by the Office of the Revisor, as they are unnecessary and lack the force of law. However, I have also seen declarations of this sort used in the justification for the issuance of a nonferrous permit to mine. For example, see finding 1 of Northmet Project Permit to Mine Findings of Fact, Conclusions, and Order of the Commissioner (page 1): “It is the policy of the state to provide for the diversification of the state’s mineral economy through long-term support of mineral exploration, evaluation, environmental research, development, production, and commercialization.” Minn. Stat. § 93.001; cf. Minn. Stat. § 93.43(a) (“The business of mining, producing, or beneficiating nonferrous metallic minerals is declared to be in the public interest and necessary to the public welfare, and the use of property therefore is declared to be a public use and purpose.”). To effectuate this policy, the DNR has been granted the authority to issue nonferrous permits to mine. As you can see, the language in similar declarations of policy have been used as the basis for permitting authority for nonferrous mining. Therefore, if a declaration (or declarations) of state policy are included in the proposed legislation it should make it clear that it is the policy of the state to protect Minnesota resources and the health of its people. Here is the current proposed language: Section 2. 93.5121 DECLARATION OF POLICY It is the policy of the state to provide for the beneficial and orderly development of the state's gas resources through laws and policies that prevent waste, avoid the drilling of unnecessary wells, protect correlative rights, and provide for the reclamation of gas resource development locations in a manner that controls adverse environmental effects. RECOMMENDATION: Either delete Minn. Stat. 93.5121 from the proposed legislation or add “, protects natural resources, and protects public health.” to the end of the declaration.	Process	Statutory language
352	Similar to the above section, I recommend the removal of Minn. Stat. 93.5171, the declaration of state policy regarding the reclamation of gas resource development locations. There should be specific standards included in the draft legislation and the rules to be developed about reclamation, which renders this declaration unnecessary. If the declaration remains, it should be amended to remove “and recognizing the beneficial aspects of gas resource development.” This statement is unnecessary, not actionable, and not relevant to this section of the legislation. As currently proposed, this section reads: Section 10. 93. 5171 DECLARATION OF POLICY. In recognition of the effects of the development of gas resources upon the environment, it is the policy of this state to provide for the reclamation of gas resource development locations where such reclamation is necessary, both in the interest of the general welfare and as an exercise of the police power of the state, to control possible adverse environmental effects of the development of gas resources, to preserve the natural resources, and to encourage the planning of future land utilization, while at the same time promoting the orderly development of gas resources, the encouragement of good gas resource development practices, and recognizing the beneficial aspects of gas resource development. RECOMMENDATION: Delete 93.5171 as a whole, or delete “and recognizing the beneficial aspects of gas resource development.”	Process	Statutory language
353	4) Account for the possibility of an environmental impact statement for a gas development proposal in the proposed legislation There are a number of places in the proposed legislation where an environmental assessment worksheet (EAW) is mentioned, but no mention of an environmental impact statement (EIS). This should be corrected to allow for the state to recoup the cost of an EIS if one is ordered (either by the Minnesota DNR or a court,) as well to clarify the possibility of an EIS being ordered if “there is the potential for significant environmental effects” (Minn. Stat. 116D.04, subd. 2(a)). The intent of the addition of subd. 16(a) to Minn. Stat. 116D.04 appears to be implementing the GTAC recommendation of the Minnesota Environmental Quality Board (EQB) to “require a mandatory environmental assessment worksheet for any gas resource development project.” I appreciate the recognition that while rules are being developed (including any mandatory category environmental review rules), the draft legislation should eliminate confusion about whether this sort of development will require an EAW. I also appreciate the EQB’s statement that “requiring an EAW for any gas project as a part of the interim temporary framework allows the EQB and permitting agencies to gather information about potential environmental effects, supporting future work to further develop a mandatory category in rule that includes a scientifically supported size threshold for the type of projects expected to take place in Minnesota.” However, the statute can and should establish that an EAW is required for all gas development proposals, before and after completion of rulemaking. RECOMMENDATION: Delete “Until a final rule is adopted,” from the proposed subd. 16(a) to Minn. Stat. 116D.04.	Environmental_review	General

354	In addition, there are other sections of the proposed legislation that require the applicant to reimburse the State for the cost of conducting an EAW, but do not include a requirement to pay for an EIS. For example, from the proposed legislation: Section 18. 93.5177 ENVIRONMENTAL REVIEW FEES. Subdivision 1. Assessment. The commissioner of natural resources must assess a gas resource development permit applicant the reasonable costs of preparing, reviewing, and distributing the associated environmental assessment worksheet through the Record of Decision, as required by (EQB draft statute number). The applicant and the commissioner must enter into a written agreement to cover the estimated costs to be incurred by the commissioner. Subd. 2. Full cost to be paid. The commissioner must not commence the preparation of an environmental assessment worksheet until the full assessed cost of the environmental assessment worksheet is paid pursuant to subdivision 1. Other laws notwithstanding, no state agency may issue any permits for the development of gas resources for which an environmental assessment worksheet is prepared until the final assessed cost for the environmental assessment worksheet has been paid in full. To eliminate confusion and to ensure that the Minnesota DNR is reimbursed for the cost of preparing an EIS if one is required, this section should be revised to add “and/or EIS.” RECOMMENDATION: Insert “and/or environmental impact statement if required” after “environmental assessment worksheet” in Minn. Stat. 93.5177 subd. 1 and subd. 2.	Environmental_review	EAW and EIS costs
355	5) Clarify that once rules are established permits issued under the temporary framework must be reissued in accordance with the newly adopted rules, and are not grandfathered in perpetuity The proposed legislation would result in permits issued under the temporary framework remaining valid in perpetuity, while standards developed under the rulemaking would not apply to the permit. This is found in the proposed legislation under Section 14, Minn. Stat. 93.5174 Gas Resource Development Permit: Subd. 2. Permits issued during rulemaking. A gas resource development permit issued during the pendency of expedited rulemaking authorized under 93.514 will not expire once those rules are promulgated, so long as the person holding that permit continues to operate under permitted conditions. Should a person holding such a permit apply for a permit amendment after rules are promulgated, the promulgated rules will apply to operations covered by both the amendment and the original permit, and the application for a permit amendment must include such information as the commissioner may require as in subdivision 1 and in accordance with promulgated rules for the entire project. In combination with the lack of a fixed, temporal term to the permit, and the irrevocable nature of permits issued, this subdivision could incentivize a rush to apply for temporary permits before rules are adopted. It could disincentivize applying for needed permit amendments to preserve the grandfathered temporary permit. It could also lead to slower adoption of permanent rules since there will not be pressure to complete the rulemaking from the regulated party. None of these are desirable conditions. There is a need for regulatory certainty, and a reasonable case can be made for a period of time after the adoption of permanent rules for a temporary permittee to receive a permit under those rules. But the current language is too permissive. RECOMMENDATION: Replace “will not expire once those rules are promulgated” with “will expire three years after those rules are promulgated” in Minn. Stat. 93.5174 subd. 2. RECOMMENDATION: Include a fixed, temporal term of 10 years or less for all permits issued (either temporary or under the permanent rules.)	Gas_production_permitting	Temporary permits
356	RGGS recognizes the difficulties that come with the task of regulating mineral development and can appreciate the state’s coordinated effort to make production of the discovered helium possible with new legislation.	Process	General
357	The approach as outlined in the published draft requires a significant amount of investment focused on production prior to allowing a well to be drilled. This will discourage exploration and potentially waste valuable time and funds. Given that this discovery is the first of its kind in the state, we believe an approach that allows the operators and the regulatory agencies to proceed one step at a time would be a better option.	Process	Burdensome regulations
358	To clarify, our suggestion is that drilling and exploration requirements should be a separate effort from permitting for production and associated facilities. Development of this resource is still in a very early stage, and it is highly improbable that an operator would be able to delineate the needs of its production facility without first drilling multiple wells. Putting the regulatory and environmental requirements for production ahead of granting drilling or exploration permits will likely cause dual efforts by both the operator and the agencies, as undoubtedly there will be changes to the plan after wells are drilled and the geology is further understood	Environmental_review	No mandatory EAW for exploration
359	The same thing can be said for defining a spacing unit based on drainage without having ever drilled a well. RGGS recommends the minimum spacing unit, as defined in the draft, be required to drill, and a second unit designation process after, should the operator look to then move into the production phase.	Spacing_unit	Size and shape
360	Should any party within the pool that is a designated distance from the wellbore be unwilling to grant a lease, the willing parties should not be penalized, and the unwilling party should simply be excluded from the designation.	Pooling_orders	Compensation for nonconsenting owners
361	The distance requirement to a property line between minerals owners is another item to be considered, a simple recommendation utilized in other states would be somewhere between 320-500 ft.	Spacing_unit	Property line setbacks
362	As fields are delineated, and more is understood regarding the drainage potential of a well, the DNR could then be granted the ability to set forth special field rules that apply to a specific area containing characteristically consistent properties controlling production of a specific gas play.	Spacing_unit	Who proposes spacing units
363	The drafted regulations are borrowed from a framework... based on policies that seek to slow and hinder further exploration and development.	Process	Burdensome regulations
364	The drafted regulations are borrowed from a framework formed by oil and associated hydrocarbon gas production and furthermore based on policies that seek to slow and hinder further exploration and development. RGGS’s concern with such a foundation is that the agencies tasked with oversight and the operators seeking to drill will encounter unnecessary difficulties due to rules that do not translate to the industry associated with helium and hydrogen exploration and production. The result of such a foundation would likely require changes to the laws and delay the exploration and production of the commodities that are the target of the exploration efforts specific to Minnesota. Additionally, it is unlikely that Minnesota hosts reserves of producible quantities of oil or hydrocarbon gas and gas liquids due to the lack of preserved sedimentary basins and history of intense glacial erosion. The state's geology is dominated by igneous and metamorphic terranes which are not prospective targets for hydrocarbon resources.	Process	Burdensome regulations
365	From the mineral owner’s perspective, we seek to remove hurdles that will discourage prospecting companies from making valuable discoveries. As written, the drafted recommendations would intrude on the rights of a mineral owner to responsibly explore for gases that do not pose a threat to the neighboring lands or the environment.	Process	Burdensome regulations

366	Helium and hydrogen are gases that are in high demand by our technology driven society. As you are likely aware, just to name a few applications, helium is used in space exploration, advanced medical imagery, and the manufacturing of fiber optic cable. Hydrogen if found within a reservoir in its isolated form, will greatly aid in developing low carbon footprint energy options. The ability to capture these gases is driving a new wave of explorers eager to meet the demand for them.	Process	Timing of resource extraction
367	We hope to have future conversations with legislators and the committee to further this effort, and to encourage future exploration and development of precious resources that will aid the country as the United States's helium reserves have been considerably depleted, and the potential for hydrogen as an energy alternative grows.	Process	Timing of resource extraction
368	1) The Legislature should refer this matter for rulemaking. Proceeding with gas resources development under a temporary legislative framework is inconsistent with the nonferrous mining process cited as an exemplar, and is unsupported by facts, premature, and would fail to protect Minnesota's environmental and financial interests.	Process	There should be no temporary framework
369	2) The Legislature should require an independent assessment of the extent and types of gas resources in Minnesota; potential effects of gas exploration and commercial extraction on Minnesota's natural resources and climate sustainability; and potential state revenue that could be obtained by taxing this development. (ed. note basis for comparison is presumably the Minnesota Regional Copper-Nickel Study)	Environmental_review	Need for baseline data
370	DNR's proposed statutory language would allow gas resource exploration or commercial extraction "activities" (so long as the surface was not disturbed by a well location) within the Boundary Waters Canoe Area Wilderness Mineral Management Corridor and within one-fourth mile of Voyageurs Park, state wilderness areas, the Agassiz and Tamarac National Wilderness areas and the Pipestone and Grand Portage National monuments, state scientific and natural areas, state parks, calcareous fens, or within national or state wild, scenic, or recreational rivers, or the area adjacent to Lake Superior's North Shore. (GTAC at 52-53). DNR's recommendations do not refer to these allowed activities, and no analysis in this report described the impacts of gas exploration and commercial extraction on groundwater, proximate surface water, or sensitive ecosystems.	Environmental_review	Environmental impacts
371	The proposed permitting structure (DNR-4 through DNR-12) suggests that a permit would be granted for "gas resource development" when a proposer seeks to start exploratory drilling. However, no permit, public process, or environmental review would be required when and if a proposer seeks mass commercial production of a gas resource. (GTAC at 13). The proposed legislative language uses a phrase, "gas resource development," which does not distinguish between exploration and mass commercial production and allows a temporary exploration permit to become a permanent gas production permit if amended in a process that includes no more than DNR submittals. (GTAC 48, 49-54).	Gas_production_permitting	When is a permit needed
372	An environmental assessment worksheet (EAW), the brief screening document that does not consider alternatives, would be required before exploratory drilling for gas. It is undisputed that "Minnesota does not have a history of gas production within established well fields in the state, or even (at present) a good understanding of where gas resources might be located, or the size and shape of any gas reservoirs." Id. An EAW prior to gas resource exploration might address the location of a well, but could not analyze the scope or impacts of extracting an unknown gas resource of an unknown size. Issues such as climate change impacts and safety risks could change based on the nature of the resource proposed for extraction. The gas deposit where helium was detected in northern Minnesota in 2024 is mostly carbon dioxide (CO2), with resultant climate issues if the CO2 is vented to the atmosphere and acidity impacts if the CO2 mixes with groundwater. If hydrogen is found in a gas deposit, it is highly explosive and could be radioactive.	Environmental_review	Carbon and climate change
373	It is contrary to Minnesota policies and statutes for environmental review and administrative procedures as well as those for nonferrous mining to allow DNR to make an exploratory permit morph into a permanent commercial extraction and production permit without standards for approval or denial, contested case hearing, public process, or environmental review. (See GTAC 49-54). DNR's proposed process may protect the hypothetical owners of property and gas, but not Minnesota's natural resources or residents. Any proposed framework for gas exploration and extraction must require a permit prior to commercial production, with environmental protection and safety standards for permitting, robust environmental review, and public notice and comment.	Gas_production_permitting	When is a permit needed
374	Next, DNR's recommendations for contested case hearings fail to include tribal governments among the governments that can petition for a hearing (GTAC at 15, 55) and refer only to landowners, although impacts of gas extraction can also affect air and drinking water. DNR also proposes that constraints on gas resource drilling and extraction will be based on ownership of land. Specifically, the DNR recommends that only unleased gas interests "tied to an American Indian tribe or band owning reservation lands . . . should be shielded from pooling orders." (DNR-28). Proposed draft legislation states that the only exclusion from a pooling order is for lands owned by "an American Indian tribe or band." (GTAC at 45). This framework may effectively exclude tribal interests in gas resources even on its own reservation, unless the Tribe owns a particular parcel of land.	Pooling_orders	Legal challenge process
375	The Minnesota Department of Revenue (DOR) proposed not only to tax gas using the Occupation Tax and Gross Proceeds Tax mechanisms applicable to mining, but to add oil to its recommendation. (DOR-1 through DOR-6). DOR cited no analysis of mining revenues demonstrating that they are fair, efficient, or the optimal way to benefit Minnesota taxpayers. DOR also did not examine the similarities and differences between the two industries on issues such as capital requirements, profit potential, or time horizons. WaterLegacy believes that determination of the most beneficial way for Minnesota taxpayers to obtain revenue from gas exploration and extraction requires more than a cookie-cutter adoption from the mining industry, which may or may not be a positive example. We are not proposing a specific method of taxation, but are strongly recommending that no tax structure be adopted in statute or rule until a detailed analysis has been done and shared with the public as well as legislators. That analysis should explain the effective rate of taxation, the timing of revenue, predicted revenue streams, and how revenue will be directed (e.g., state general fund, agency, or local governments) under various potential taxing regimes.2	Revenue_generation	Need for economic analysis
376	In a different way, the DNR's recommendations for financial assurance based on nonferrous mining are a poor fit for a potential gas industry. Current rules for nonferrous mining financial assurance pertain exclusively to costs for reclamation, which can be substantial in a mining context. The costs for sealing gas wells or reclaiming drilling sites are likely to be modest. Significant costs to taxpayers from gas exploitation could include effects of gas leaks, groundwater contamination, or explosions. To protect taxpayers from the financial risk posed by these occurrences would require a financial responsibility paradigm, not a cut-and-paste from nonferrous mining rules.	Financial_assurance	FA structure
377	For each of these reasons and many more, Minnesota should not undertake to issue new permits for an unfamiliar industry with substantial environmental risks and the potential for substantial revenue without a thoughtful and analytical rulemaking process.	Process	There should be no temporary framework
378	Different types of gas (e.g., helium as compared to natural gas) not only might have different potential for development, profit, and state revenue, but are virtually certain to have different potential effects on Minnesota's air, water, land, and climate sustainability. In the mining arena, more robust regulations were enacted for nonferrous mining than for ferrous mining. It is irresponsible to assume without evidence that no distinctions should be made between regulatory requirements for different types of gas.	Process	Robust regulation

379	The water-rich ecosystems in Minnesota where gas resources may be found may also require unique analysis or protections. Certainly, the types of "activities" that must be restricted in proximity to particular resources, including drinking water sources as well as wilderness, parks, monuments, and other protection areas, should be assessed along with the geography, geology, and hydrology of Minnesota gas resources.	Environmental_review	Alternative site analysis
380	There are also pragmatic reasons to require assessment of Minnesota gas resources rather than speculation as to the nature and extent of the resource prior to permitting for exploration, let alone the DNR's all-in-one permanent extraction and production permit. Even the simple recommendation for spacing of wells to protect correlative rights of owners of a potentially shared resources (e.g., DNR-18 to DNR-20) requires more knowledge. It is axiomatic that prescribing well spacing without knowledge of the size, horizons, or location of a gas resources is not advisable and risks being ineffective, inefficient, and/or unfair.	Environmental_review	Need for baseline data
381	Several Minnesota Department of Health (MDH) recommendations made in the GTAC process are fundamental to consideration of gas exploration and extraction, do not imply permit issuance prior to rulemaking, and are ripe and timely to set a policy framework for future rulemaking. The Legislature should adopt these recommendations in statute prior to rulemaking or permitting to protect Minnesota residents and water resources. The following statutory repeals would facilitate rulemaking governing regulation of gas wells: MDH-1: Repeal Commissioner of Health's existing authority to explore and prospect for natural gas and oil. MDH-2: Repeal natural gas from the well definition; and grant new rulemaking and fee authority to the Commissioner of Health for the regulation of gas wells. MDH recommendations MDH-3 through MDH-6 have merit and should be considered in rulemaking. They would require licensing by MDH for work on gas wells, construction notification, fees, access by MDH, and notification of occurrences with the potential for environmental harm.	Process	There should be no temporary framework
382	In addition, WaterLegacy requests that the following MDH recommendations be enacted by the Legislature as part of the basic framework of environmental, health, and safety protection within which rules will be adopted to regulate gas exploration and production: MDH-7: A person must not use a gas well to inject or dispose surface water, groundwater, or any other liquid, gas, or chemical. MDH-8: A person is prohibited from hydraulic fracturing a gas well. MDH-9: A person must ensure that drilling fluids, cuttings, treatment chemicals, and discharge water are disposed of according to federal, state, and local requirements. MDH-10: Drilling fluids used during the construction of a gas well must be water or air based and additives must meet the requirements of ANSI/NSF standard 60. MDH-11: A person must meet gas well casing and grout requirements. MDH-12: A person must meet gas well isolation distances. MDH-13: A person must protect groundwater during the construction and sealing of a gas well. MDH-14: A person must seal a gas well to prevent contamination of groundwater and the environment. MDH-15: A person must submit a gas well sealing notification and fee for each proposed gas well to be sealed. These provisions would provide a sound minimum standard for any activities pertaining to gas wells in Minnesota.	Gas_wells	Regulatory oversight
383	• A gas resource exploration permit must be based on a detailed plan for drilling location, materials, and practices and DNR's must explicitly state that no extraction or commercial production are authorized by DNR's exploration plan approval. That exploration permit should be subject to public notice and comment and the contested case hearing process.	Gas_production_permitting	When is a permit needed
384	• A gas resource exploration permit must be preceded by a mandatory EAW with DNR as the RGU. DNR should be entitled to obtain costs for preparation of that EAW from the proposer	Environmental_review	General
385	• Gas resource extraction or commercial production should require a separate gas extraction/production permit subject to public notice and comment and the contested case hearing process.	Gas_production_permitting	When is a permit needed
386	• Tribal governments should be listed among the governments entitled to file petitions for a contested case, and petitioners should also include "residents of Minnesota" that would be affected by the proposed operation to avoid exclusion of persons whose air or drinking water or would be contaminated by gas extraction.	Process	Contested case and legal
387	• The DNR must be required to prepare an environmental impact statement (EIS) prior to issuing a gas extraction/production permit. DNR should be entitled to obtain costs for preparation of that EIS from the proposer (or potentially allocate costs among owners of the gas resource).	Environmental_review	Need for comprehensive EIS
388	• Permitting standards should, in addition to the minimum requirements contained in MDH recommendations listed in Section 3, place restrictions on extraction to protect sensitive resources and require use of best available technology and design to minimize safety, climate, and environmental risks, some aspects of which may be described in rules.	Gas_production_permitting	Need for all required permits
389	• In addition to financial assurance to seal wells and reclaim drill locations (GTAC at 50), rules should require funding of financial responsibility to protect taxpayers from liability resulting from leaks, contamination of water, explosions, or other damage to health, safety, or environmental quality.	Financial_assurance	FA structure
390	• Rules should also set forth the criteria for spacing orders; requirements for disclosure of gas exploration results, terms and protections that must be included in a pooling order application;	Pooling_orders	Application process
391	• Rules should also set forth... the criteria for policies related to state ownership of gas resources;	Process	Leasing
392	• Rules should also... (include) guidance to protect correlative interests of tribes on their reservations and tribal interests in exercise of treaty-reserved rights in ceded territories.	Correlative_rights	General
393	Conclusion: WaterLegacy recommends that the Legislature take the following actions this session: 1) Direct the GTAC agencies to conduct a Minnesota Gas Resources Assessment of the nature, extent, and location of Minnesota gas resources; the environmental, health, and safety risks posed by their exploration and extraction/production; and methods to optimize taxpayer revenue and minimize taxpayer risk. Provide budgetary resources for this assessment.	Process	General
394	2) Direct the GTAC agencies, particularly DNR and MDH, after the Minnesota Gas Resources Assessment Study is complete, to conduct a rulemaking process for regulation and permitting of gas resources exploration and extraction/production while protecting Minnesota taxpayers, health, safety, climate sustainability, and natural, historic, cultural, and treaty-reserved resources. Provide budgetary resources for this process over time.	Process	General
395	3) Enact MDH recommendations in Section 3 above that enable rulemaking (MDH 1 and MDH 2) and that set appropriate minimum standards for any gas wells or drilling processes in Minnesota (MDH-7 through MDH-15).	Process	General
396	4) If the Legislature decides to proceed with permitting prior to rulemaking despite recommendations to the contrary, it is requested that any legislative framework adopt the concepts described in Section 4 of these comments.	Process	General
397	WaterLegacy appreciates the opportunity to comment in this matter, even with the time constraints that precluded a more detailed analysis.	Process	General
398	We believe that other members of the public are also interested in commenting, and request that a comment process be extended through the end of January 2025.	Process	General

399	It would be highly regrettable if Minnesota made decisions on an important new industrial development without a thoughtful and deliberative process, including resource assessment, rulemaking, and a robust public process.	Process	General
400	I am not well versed in gas exploration processes, and for this reason alone strongly encourage the GTAC to consult with the only company actively exploring for a primary gas resource in the State of Minnesota on: 1.Exploration process for gas in this specific setting 2.Order of operations with respect to exploration processes 3.Utility of exploration boreholes versus production boreholes 4.How their approach to gas exploration in Duluth Complex may have differed if the original discovery NQ core hole had not already produced strong indication of He	Process	Robust regulation
401	Following discussion with GTAC members and associated regulatory entities to date, I am concerned with the regulatory framework being proposed at this time.	Process	General
402	More specifically, the requirement for a protracted permitting process (EAW) and placement of a sizeable financial “bond” (for lack of a better term) for ANY type of gas exploratory drilling effectively negates the exploration process.	Environmental_review	No mandatory EAW for exploration
403	The act of drilling defines the “truth” in an exploration program. The surface mapping, sampling, geophysics and remote sensing data collection give indicators as to the presence or absence of subsurface geology, but discovery takes place ONLY with drilling. The exploration process needs to have as many flexible tools at its ready to condemn ideas or make initial discoveries at reasonable cost- and time-frames. The current structure proposed by GTAC runs counter to the intention of exploratory drilling, or at least presumptive of how exploration (for solid minerals or otherwise) occurs.	Environmental_review	No mandatory EAW for exploration
404	The requirement of a $50k application fee and a multi-year evaluation/permitting process to confirm or condemn an exploratory concept via drilling will effectively negate that part of the exploration process. If this is the intention of GTAC, then I STRONGLY suggest discussing the exploration process with the only company conducting it in this state.	Gas_production_permitting	Permit fees too high
405	With respect to the distinction between a gas exploration well, appraisal well, and production well, I strongly recommend that the GTAC consider some clear guidelines on what physical parameters defines each. For example, borehole diameter, construction methodology, surface footprint for required support equipment, etc. These facets of the gas resource exploration, evaluation and production processes should govern the timing and need for larger scale permitting considerations; not the “intention” of the exploration boring.	Gas_production_permitting	When is a permit needed
406	it is critical that Minnesota consider the rule making process surrounding regulation of this industry carefully in the pursuit of safe, effective and efficient regulatory frameworks.	Process	General
407	We prefer our country and all 50 states (MN included) to strive for energy independence! This involves safe mining, derilling, trenching, disposal of sludge......we cannot afford to be a raw inporter of miinerals that we already own. Mike and Ilyne Rasmussen NW Angle	Process	General
408	I work for MnDOT in permitting in District 1. This will potentially impact MnDOT with access permits. I was unable to open the link to the draft to view it. Jeff Swenson jeffrey.swenson@state,mn,us	Process	General
409	My input is short: Minnesota does not regulate above ground mining and oil/gas pipelines to protect watershed and aquifer resources. Given that very poor track record, my comment is: Do not allow exploration and/or implementation of exploiting gas resources anywhere in the State of Minnesota.	Process	Poor track record
410	If we can't ensure the state’s natural resources, then it's no go! MNDNR	Process	General
411	Comment on GTAC gas exploration and production guidelines: In general, who can understand the red tape, much less comply, in a timely manner and at reasonable expense to a 5 agency and legislative bureaucratic process to allow a company to explore and produce gas in Minnesota? Just reading the requirements, which don’t include details, is enough to turn any beneficial business away that could possibly benefit Minnesotans. For both the use of the product and jobs created. Not to mention taxes and fees to the State. The regulations and process to obtain the permits are beyond complicated, burdensome, and costly to the point of absurdity. Duplicity and muti-agency requirements is a bureaucracy nightmare. Unlike government agencies, who never pay the price for their irresponsibility, lack accountability, and have no bottom line to be held to, businesses live in a world where these issues matter for survival. Keep in mind, the State’s unnecessary expensive red tape is reflected in the final product cost to consumers and subject to market forces. The public pays for these inefficiencies. We who also pay your salaries as well. Everyone understands that safeguards must be in place to prevent environmental degradation from negligent or accidental mishaps or processes by mining companies. Also, that there are many “i’s” to be dotted and “t’s “ to be crossed to insure mining companies comply and act responsibly to safeguard the land and water as well as restore the land to its original state. But overkill hurts everyone. Except the Government who just levies taxes to cover their deficiencies and duplications. My suggestion is to task GTAC, and the other agencies, to meet first to eliminate their existing process and redefine it to a model where the inefficiencies are eliminated and the process simplified to a sane level that the business world has to survive in. All with achieving the goal that was intended at the start. This would require having one agency and eliminating the others along with the employees. Consider and identify “one” list of what the State needs in requirements from the mining company to comply with and the safeguards they must provide. Guaranteed and bonded. No different than what a state employee would hope to have to do if it were their dime and time being spent personally for their own endeavor. The idea the State thinks we can survive without mining and other uses of natural resources for the public needs for fear of ‘harming the environment” , is living in a vacuum and a fictitious ideology. The two can coexist.	Process	Burdensome regulations
412	My primary concern is that the interests of the public inevitably seem to become secondary to the interests of businesses or individuals standing to profit from the exploitation of public resources. Is it possible to enforce a strict code of ethics for those participating in preparing this regulatory framework. Conflicts of interest need to be examined carefully and rigorously. Previous, current, or potential employment by business interests involved needs to be addressed. Are those helping write the regulations today going to be employed tomorrow by those subject to those regulations?	Process	Ethics standards
413	Automatically deferring to industry experts has to be unacceptable. Critical examination of their inputs by in-house or academic experts should be required. Industry representatives have a fiduciary responsibility to maximize profits for their shareholders - not to protect the public or insure appropriate compensation to the state for the resources being exploited.	Process	General

414	R.E. GTAC draft recommendations / statutory language : I did not see any mention of the chemicals used in drilling, like PFAS which could contaminate the water aquifer in the area. Which chemicals are being used in this operation? Are they a danger to our water supply here?	Environmental_review	Environmental impacts
415	Is the carbon coming from this deposit being sequestered and used commercially or being released into the atmosphere?	Environmental_review	Carbon and climate change
416	Increased traffic on the Dunka River Road will cause wear and tear on that US Forest Service road and there will be increased traffic on Lake County Highway #2, which is severely subject to frost heave and is in much need of repair already from White Pine picnic area up to the Greenwood Lake access area. Who is going to pay for that? Zeke Delz	Environmental_review	Traffic and roads
417	General input from the Natural Resources Research Institute, University of Minnesota: • It is important to distinguish between trapped or "natural" geological hydrogen and "induced" geological hydrogen. While the former may be accessible via conventional methods similar to those used for natural gas, the latter is the hypothetical product of induced reactions in-situ between pumped high-pressure steam and catalysts and existing geological formations and thus may require additional regulatory attention. Hydrogen from either source will need to be collected and piped to the surface where it can be cleaned, used, or stored. • The extracted gaseous mixture will consist of hydrogen, water vapor, carbon dioxide, methane, hydrogen sulfide, and other gases. Beneficiation of the gas mixture will involve removal and potentially, purification of non-hydrogen constituents, which may have value in and of themselves. All gas constituents will need to be properly managed under appropriate regulatory oversight.	Gas_production_permitting	Induced hydrogen
418	• Underground storage of hydrogen could be achieved using natural or manufactured hard rock cavities, or cavities produced by natural and induced geological hydrogen production, provided that these cavities were naturally or artificially lined or otherwise sealed and isolated from potential reactants or contaminants. Porous, non-reactive rocks at or near the surface might also be appropriate for hydrogen storage, if they were similarly sealed and isolated from reactants and contaminants. • Issues associated with hydrogen leakage, reactivity, and metal embrittlement must be considered for any storage, transfer, and delivery of natural and induced geological hydrogen. R.T, Weberg, Executive Director, NRRI	Gas_production_permitting	Storage, transfer and delivery
419	Public Comments on GTAC Recommendations and Statutory Language for Permitting Gas Resource Development Submitted by Area Partnership for Economic Expansion (APEX) APEX appreciates the opportunity to provide feedback on the GTAC recommendations. We believe Minnesota's potential helium and hydrogen resources represent a unique opportunity for our communities and economy. We are committed to environmental stewardship and industrial investment with a goal of regional vitality. Our concerns in the proposed GTAC language fall into four main categories: 1. Environmental Review for Exploration Drilling APEX is concerned about the requirement for mandatory environmental reviews for exploration drilling of gas resources, as outlined in the GTAC recommendations. This requirement is not imposed on any other type of exploration drilling in the state. The Environmental Quality Board (EQB) recommends a mandatory Environmental Assessment Worksheet (EAW) for any gas resource development project, including exploratory drilling (EQB-1). This places an undue burden on gas exploration activities, which are typically less impactful than full-scale production operations. We urge the GTAC to reconsider this requirement and align the environmental review process for gas exploration with that of other exploration activities in the state to ensure a fair and consistent regulatory framework.	Environmental_review	No mandatory EAW for exploration
420	2. Excessive Fees for Helium and Hydrogen Exploration The proposed fees for helium and hydrogen exploration are excessively high. The Department of Natural Resources (DNR) recommends a $50,000 application fee and a $75,000 annual permit fee for gas resource development projects (DNR-7). These fees are disproportionate to the scope and scale of this activity, particularly at the exploration level. We recommend that the GTAC adjust the fee schedule to reflect the lower impact and scale of gas exploration activities and differentiate between exploration and production permits. The size of production operations is yet to be determined and this ensures that the fees are fair and do not discourage investment in this emerging sector.	Gas_production_permitting	Permit fees too high
421	3. Requirement for Gas Companies to Pay for Environmental Assessment Worksheets (EAWs) APEX questions the requirement for gas companies to bear the costs of preparing, reviewing, and distributing Environmental Assessment Worksheets (EAWs), as recommended by the DNR (DNR-12). This requirement is unique to the gas industry and is not imposed on any other industry or project in the state. The costs associated with EAWs can be substantial and place an additional financial burden on gas companies, potentially hindering the development of gas resources. We urge the GTAC to reconsider this requirement and explore alternative funding mechanisms for EAWs.	Environmental_review	EAW and EIS costs
422	4. Fee Transparency APEX seeks transparency regarding how permitting revenue will be allocated, particularly given these funds are directed to the state's general fund without clear usage guidelines. We request a detailed explanation of how these fees will support specific activities not already covered by existing state funding or permitting revenues. APEX represents nearly 100 investor companies in Northeast Minnesota and Northwest Wisconsin. We are deeply committed to creating a sustainable future that balances environmental protection with economic vitality. While we appreciate the need to craft a regulatory structure around an emerging resource extraction industry, we believe the most productive path forward is one that: • Maintains clear, focused environmental goals • Recognizes the technical approaches and environmental impacts of the hydrogen and helium extraction processes • Supports continued economic growth and community health and well-being We are grateful for the opportunity to provide input on this important rulemaking process and look forward to continuing this critical dialogue. Rachel Johnson President & CEO Area Partnership for Economic Expansion (APEX) rachel@apexgetsbusiness.com	Gas_production_permitting	Permit fee transparency

423	116D.04 Subd. 16a. As the Responsible Govt Unit (RGU) the MN DNR will be responsible for determining if a Environmental Assmt Worksheet (EAW) is sufficient or whether an Environmental Impact Statement (EIS) will be required. The distinction between the two is "may have" potential for significant environmental effects or "does have" the potential... Which department within the DNR will be making this key recommendation and whom within the DNR ultimately makes the determination between "may" and "does"? Please confirm this determination will be made after examining the EAW worksheet. Interested, because the DNR has the difficult job of balancing sometimes conflicting duties of environmental stewardship and financial fiduciary obligations to the taxpayers, school trusts, etc...	Process	DNR conflicts of interest
424	As a neighbor to Pulsar Helium's exploratory well site, 3.5 miles away near Sand Lake, it was evident when the Q124 exploratory drilling was occurring. The 24 hour boring was very audible and the lights illuminated the night sky. I encourage those reviewing future permit applications to consider this exploratory testimony, as well as proposed future operations associated with the extraction, processing and transportation of the product(s). Questions might include: Will there be guard rails around operations (sound and light levels, days of the week, hours, etc...). Will processing occur on site and, if not, at which location? Will the Dunka River Rd be developed to the east? More broadly, what infrastructure upgrades/maintenance may be required of Lake County or the State of Minnesota?	Environmental_review	Noise / light
425	As a neighbor to Pulsar Helium's exploratory well site, 3.5 miles away near Sand Lake, it was evident when the Q124 exploratory drilling was occurring. The 24 hour boring was very audible and the lights illuminated the night sky. I encourage those reviewing future permit applications to consider this exploratory testimony, as well as proposed future operations associated with the extraction, processing and transportation of the product(s). Questions might include: Will there be guard rails around operations (sound and light levels, days of the week, hours, etc...). Will processing occur on site and, if not, at which location? Will the Dunka River Rd be developed to the east? More broadly, what infrastructure upgrades/maintenance may be required of Lake County or the State of Minnesota? If this all comes to pass, I wish to be mutually respectful neighbors with Pulsar and any other future extraction entities. That will be contingent upon fair rules and expectations being set upfront by the DNR, GTAC, legislature and governor.	Environmental_review	Traffic and roads
426	Thank you for the opportunity to provide feedback on the draft temporary framework to regulate gas resources like helium extraction. As Anishinaabeg, one of our responsibilities is to care for the next seven generations, ensuring that they have the resources they need to thrive and survive. I would like to highlight a key concern: this helium deposit is being considered primarily to support the ongoing, unsustainable consumption of a nonrenewable resource. The focus should not solely be on maintaining current helium usage, but on questioning whether such consumption is responsible in the first place. As the governmental agencies entrusted with the regulation and responsible management of our natural resources, I urge your team to consider this crucial question: Is this mining truly necessary at this moment, or should this helium reserve be preserved for future generations who may need it far more than we do today? Currently, our society is wastefully consuming this finite resource—shouldn't we first evaluate our consumption patterns and work toward using it more responsibly before expanding extraction? The issue of responsible consumption is at the heart of many of the environmental challenges we face today. I often wonder: Will this generation continue to take without regard for those who come after us, depleting the Earth's resources until there is nothing left to offer? Or will we pause and recognize that not every underground resource needs to be extracted simply because we have the ability to do so? The future hinges on the choices we make today.	Process	Consumption patterns
427	I challenge you to think beyond the present moment. Could your children or future generations rely on helium for critical medical devices? Perhaps this deposit should be preserved for those who may need it far more in the future. The decisions we make now will shape the world they inherit. I recognize that the statement above may not serve as the wake-up call needed to halt this mine's progress. However, in the spirit of providing constructive comments, I offer suggestions that could strengthen the process and ensure the health of both the people and the land surrounding this area are properly protected.	Process	Timing of resource extraction
428	First and foremost, I urge the state of Minnesota and its governmental agencies to fully engage in consultation, as mandated by law. Minnesota State Statute 10.65 clearly defines "consultation" as the direct and interactive involvement of Minnesota's Tribal governments in the development of policies that have Tribal implications. Consultation is not a passive process—it is a proactive and affirmative one, requiring the identification and active engagement of relevant Tribal governments, with their interests being considered as an integral part of the decision-making process. Consultation should have occurred before any drills were placed in the ground. It is critical that consultation, and ultimately consent, take place to ensure that Tribal nations have the authority and opportunity to protect their people, their lands, and the generations that follow. This process is not only a legal requirement but a moral imperative to respect the rights and sovereignty of Tribal nations.	Tribal_relations	Need for consultation
429	The process of extracting helium from the ground should trigger a comprehensive environmental impact statement (EIS), particularly given the potential environmental and public health risks associated with its extraction.	Environmental_review	Need for comprehensive EIS
430	Given the potential presence of harmful contaminants, the extraction of helium should trigger an EIS under the National Environmental Policy Act (NEPA). An EIS is essential for assessing the full range of environmental and public health impacts associated with helium extraction. This should include, but not be limited to: Radon and Radioactive Material Mitigation: If helium is being extracted from areas with known radioactive contamination, an EIS should assess the measures required to mitigate the release of radon and other radioactive isotopes. This includes air quality assessments, potential soil contamination, and risks of groundwater contamination.	Environmental_review	Radioactive materials
431	Water and Soil Contamination: The extraction process may involve fracking or drilling, both of which carry risks of disturbing existing contaminants or introducing new chemicals into the environment. An EIS would need to evaluate the potential for groundwater contamination, changes in local water quality, and impacts on surrounding ecosystems.	Environmental_review	Environmental impacts
432	Air Quality Impacts: Helium extraction sites may release various gases, including methane, carbon dioxide, and potentially volatile organic compounds (VOCs), which can contribute to air pollution and will contribute to greenhouse gas emissions which are currently fueling climate change. An EIS would assess the potential for these pollutants to affect local air quality and public health, especially in communities near extraction sites. Assessing how this mine may fuel the climate crisis also deserves acknowledgement.	Environmental_review	Carbon and climate change
433	Biodiversity and Ecosystem Health: An EIS would also evaluate the impact of extraction on local ecosystems, especially if the extraction site is in a sensitive or biodiverse area. Disturbing the land, water, or air around extraction sites can have cascading effects on local wildlife, plants, and the broader ecosystem.	Environmental_review	Environmental impacts
434	Public Health Considerations: Any risks posed to surrounding communities, especially those that rely on local water sources or live in close proximity to extraction sites, must be assessed. The release of contaminants, the risk of radon exposure, and the potential for other health impacts must be thoroughly evaluated in an EIS. An EIS would not only ensure compliance with environmental laws and regulations but also provide transparency, allowing for a broader public discussion about the environmental and health consequences of helium extraction. This process would allow stakeholders, including local communities, tribal nations, and environmental groups, to provide input and ensure that the potential risks associated with this activity are carefully evaluated and addressed before any extraction takes place.	Environmental_review	Need for comprehensive EIS

435	The Minnesota Pollution Control Agency (MPCA) should serve as the Responsible Governmental Unit (RGU) for overseeing the regulatory processes associated with this helium extraction project. The MPCA is tasked with the critical responsibility of ensuring that Minnesota's natural resources are protected from pollution, and that public health is safeguarded from environmental hazards. This responsibility encompasses a wide range of issues, including air and water quality, waste management, and land reclamation. Given that this helium extraction project has the potential to release harmful contaminants into the environment, the MPCA's involvement is necessary to assess and mitigate any risks associated with the operation.. This oversight is not only necessary for compliance with Minnesota's environmental laws but also essential to uphold the health and safety of both current and future generations.	Environmental_review	MPCA should be RGU
436	Tribal Nations must be fully compensated for both the potential damages to their treaty resources and the costs associated with studying the impacts of this helium mine. Moreover, any profits generated from this extraction should be shared with Tribal stakeholders. The land beneath which this helium deposit resides is part of the ancestral treaty territories of Tribal Nations. While these treaties were often negotiated under duress and in inequitable conditions, they nevertheless established the legal foundation for Tribal land and resource rights. These agreements recognize the rights of Tribal Nations to hunt, fish, gather, and protect their resources across vast territories, including those that may be impacted by this proposed mining operation.	Tribal_relations	Usufructuary rights
437	Tribal Nations must be fully compensated for both the potential damages to their treaty resources and the costs associated with studying the impacts of this helium mine. Moreover, any profits generated from this extraction should be shared with Tribal stakeholders. The land beneath which this helium deposit resides is part of the ancestral treaty territories of Tribal Nations. While these treaties were often negotiated under duress and in inequitable conditions, they nevertheless established the legal foundation for Tribal land and resource rights. These agreements recognize the rights of Tribal Nations to hunt, fish, gather, and protect their resources across vast territories, including those that may be impacted by this proposed mining operation.	Tax_distribution	Tax proceeds to Tribes
438	Moreover, Pulsar, the company interested in helium extraction, has stated that mining will not begin for over a year. This presents a valuable opportunity to develop a robust regulatory framework that ensures the responsible management of Minnesota's resources. During this time, it is essential to prioritize the protection of Tribal sovereignty, uphold the rights of Tribal Nations, and safeguard the health of both people and the planet. The focus must be on ensuring that the well-being of communities and the environment are prioritized over corporate profits. This is a critical moment to ensure that any mining activities and future gas extraction are conducted with respect for our natural resources and the rights of those who have long cared for them. Miigwech for considering my comments. I trust they will be given serious consideration throughout this process. Leanna Goose Co-Facilitator, Rise and Repair Coalition	Process	Robust regulation
439	(14)The commissioner may deny, suspend, revoke or modify a gas resource development permit or assess civil penalties **IR:** (A schedule of fees for violations should be established) if the permittee fails to comply with any portion of this part.	Health_and_environmental_quality	Violation fines
440	MDH-7, MDH-8 prohibits injection or disposal of liquid, gas, or chemicals in gas wells, and acknowledges the US Environmental Protection Agency's federal permitting authority for Class 2 injection wells. The GTAC should be transparent with the public and the Legislature in that the USEPA is not bound by state directives to accelerate environmental review and permitting of a gas resource development project. Additionally, a gas resource development project should not move forward, under either temporary or permanent state permitting, unless and until it has secured all necessary permits, including a federal Class 2 injection well permit.	Health_and_environmental_quality	Class II injection wells
441	An EIS is needed to assess the potential need for deep injection wells or other pollution control methods that may be required to protect human health and the environment. Both the EA and EIS costs should be borne by the applicant and an EIS must be mandated for every proposed gas project.	Health_and_environmental_quality	Class II injection wells
443	The Minnesota legislature directed the Minnesota Department of Natural Resources (DNR) to form and lead the Gas Resources Technical Advisory Committee (GTAC). The multi- agency committee was charged with developing recommendations on a temporary regulatory framework for gas projects during rulemaking. Other state agencies on the committee include the Environmental Quality Board (EQB), Department of Health (MOH), Pollution Control Agency (MPCA), and Department of Revenue (DOR). State agencies in Minnesota have a responsibility to consult with tribes on a government-to-government basis. As an example of this consultation, processes have been put in place for mining environmental review and permitting. While this process has not been perfect, it has evolved over time and provides a structure to consult with tribes through the development of industrial projects. For the GTAC initiative, appropriate tribal involvement and consultation did not occur. Proper consultation provides an opportunity for tribes to provide early and meaningful input. To our understanding, tribes were not invited to be part of the GTAC or given the opportunity to provide any input during development of the recommendations. Recommendations were provided to tribal staff on 11/15/2024 with a review and comment period through 12/1/2024 before public release on 12/2/2024. Tribes could further comment during the public period through 12/23/2024. This did not allow for proper tribal consultation before public release, and any tribal input received during the initial comment period did not result in any changes to the recommendations that were released to the public. This lack of consultation was a significant step backwards in Minnesota's responsibility to work appropriately with tribes.	Tribal_relations	Need for consultation
444	The recommendations included in the plan are to use the mining regulatory and financial assurance frameworks as structures for gas development projects. Varied opinions probably exist on how robust these frameworks are or maybe more specifically on how they are implemented. Perhaps these frameworks are a starting point but not perfect templates to follow.	Process	Robust regulation
445	Under the proposed recommendations, a permit application fee would be $50,000 and an annual permit fee would be $75,000. These fees would cover costs incurred by the Minnesota DNR. Tribes (and other state and local agencies) also incur costs during the environmental review and permitting processes. These fees should be further evaluated. Perhaps fees should cover costs and provide funding to tribes for their participation at appropriate times and levels throughout processes.	Gas_production_permitting	Permit fees duplicated to Tribes
446	The Minnesota DNR does not propose a revenue stream linked to gas production and instead would use an annual permit fee. We would like to understand more about this approach and further discussion could be helpful to determine if a revenue stream would be more suitable.	Gas_production_permitting	Permit fee transparency
447	In addition, consultation is needed on the occupation tax and gross proceeds tax. Gas development and other projects impact ceded territories and the exercise of rights guaranteed by treaty with the United States. How should these taxes be applied in ceded territories where tribes have interests and treaty rights? Discussion and agreement are needed on how tribes should be included in the process or receive any benefits from these taxes.	Tax_distribution	Tax proceeds to Tribes
448	Under the proposed temporary regulatory framework, permits are good for the lifetime of a project and facilities will not need to comply with requirements under a permanent regulatory framework when developed. While it is understood that a permitted operation would want some regulatory certainty, this process could result in a significant permitting gap or concern unaddressed during an entire project. This feels like potential "fast tracking" of first projects. A more conservative and protective approach should be followed to only permit projects when a permanent regulatory framework is in place. Regulators should not rush and be pressured into pushing projects through immediately before an appropriate permitting process is developed and approved.	Gas_production_permitting	Temporary permits

449	The proposed framework also recommends that an Environmental Assessment Worksheet (EAW) be prepared for projects. This is not a sufficient environmental review process, as EAWs are used for projects anticipated to have less significant and shorter impacts on the environment. This again feels like "fast tracking" projects without the necessary review process. An Environmental Impact Statement (EIS) should be required to fully understand impacts from a project. Tribal consultation is also needed during the environmental review process, and an EIS would better provide that opportunity.	Environmental_review	Need for comprehensive EIS
450	In addition, the document states that federal, state, or local government can file a petition for a contested case hearing. It is our understanding that tribes also have that ability.	Process	Contested case and legal
451	Pooling and pooling orders could be contentious and controversial issues, and more evaluation seems needed on these items.	Pooling_orders	General
452	The framework states that reservations or mineral interests tied to a tribe should not be tied to pooling orders. Tribes also have interests and treaty rights within ceded territories, so that also must be a consideration during pooling and permitting decisions.	Pooling_orders	Shielding from pooling orders
453	Under the current proposal, gas resource development locations must not be within some areas (ex. Voyageurs National Park, Grand Portage National Monument, state parks, etc.) but activities that do not disturb the surface are allowed within¼ mile. It also states that gas resource development locations could be allowed in places such as national wildlife refuges, state wildlife management areas, peatlands, public waters, etc., if no feasible siting alternatives exist. Further discussion and evaluation are needed to determine if the requirements for site locations and potential impact areas are appropriate.	Environmental_review	Siting and setbacks
453	In summary, we believe that additional work and appropriate tribal consultation are needed to develop a permanent regulatory framework before environmental review and permitting processes proceed for gas development projects. Thank you.	Tribal_relations	Need for consultation
455	Grand Portage is a federally recognized Tribe that has retained hunting, fishing, and other usufructuary rights in the lands and waters that extend throughout the entire northeast portion of the state of Minnesota under the 1854 Treaty of LaPointe1 (1854 Ceded Territory). The first proposed gas extraction project is located within the 1854 Ceded Territory. In the 1854 Ceded Territory, usufructuary rights were retained to ensure hunting, fishing, and gathering for subsistence, economic, cultural, medicinal, and spiritual needs could continue into perpetuity: Reserved property rights, explained by the Supreme Court in 1905 in United States v. Winans, 198 U.S. 371, are not 'a grant of rights to the Indians, but a grant of rights from them'. In Winters v. United States, 207 U.S. 564 (1908), the Supreme Court applied this principle in a water rights case. These two cases are the basis of the "reserved rights doctrine", that recognizes tribes retain those rights of a sovereign government not expressly extinguished by a federal treaty or statute."2	Tribal_relations	Usufructuary rights
456	Due to their distinct unique government-to-government relationship with the Minnesota tribes, all state3 and federal agencies4 are legally obligated to maintain treaty-reserved natural resources. All state agencies are required to consider the input gathered from tribal consultation in their decision-making processes, with the goal of achieving mutually beneficial solutions, yet this has not occurred with respect to preparation of the Draft Rules.	Tribal_relations	Need for consultation
457	The state agencies participating in the GTAC (except for MPCA5) to date have all but ignored Minn. Stat. § 10.65. The statute requires "timely and meaningful consultation" with tribes, which means "done or occurring at a favorable or useful time that allows the result of consultation to be included in the agency's decision-making process for a matter that has Tribal implications."6 A pre-public notice period of less than a week is hardly timely or meaningful. "Matters that have Tribal implications" expressly include "rules, legislative proposals, policy statements, or other actions that have substantial direct effects on one or more Minnesota Tribal governments."7 Yet the Draft Rules, which stand to directly and profoundly impact off-reservation reserved treaty resources, have been rushed through without sufficient opportunity for consultation and input, much less study. That the result of the Recommendations are proposed rules labeled as "temporary" in no way excuses this failure to consult.	Tribal_relations	Need for consultation
458	An Environmental Impact Statement (EIS) has more requirements than an Environmental Assessment (EA) to explore methods to reduce adverse environmental and human health effects, including cumulative effects, requires more public evaluation and consultation with Tribal leaders, and includes reviews by Tribal Historic Preservation Officers.	Environmental_review	Need for comprehensive EIS
459	The Recommendations suggest that mandatory category thresholds are based on project size, with EAW thresholds associated with projects of a smaller size and an EIS triggered by a larger project. However, those size thresholds are not disclosed, which must be corrected.	Environmental_review	Need to define mandatory category thresholds
460	Additionally, the Recommendations suggest that most gas wells cover about a ten-acre footprint. This directly contradicts comments made to the Band by Pulsar Helium, the company behind the initial "Topaz" project proposal located outside of Babbitt at the Bald Eagle Intrusion. Pulsar currently holds more than 4,181 acres of surface rights and has stated that the Topaz Project direct footprint will be about 50 acres, or five times the size the MNDNR has suggested would be typical for gas well projects. This is just a preliminary estimate, so the footprint and overall scale of the project could significantly increase. In addition, MNDNR has stated that Pulsar intends to lease more than 34,000 acres of state minerals for gas exploration.8	Environmental_review	Need to define mandatory category thresholds
461	The Recommendations should require that all projects require an EIS to investigate serious risks to the environment and human health, and mitigation measures must be identified before extraction begins.	Environmental_review	Environmental impacts
462	The risk of release and the concentrations of radioactive components must be discussed, and rules must be developed to ensure radioactive waste is captured and disposed of safely. Helium is created by the natural radioactive decay of radioactive elements, primarily uranium and thorium. Yet there is limited discussion regarding radioactive releases linked to gas extraction, especially concerning helium extraction. In fact, the only mention of this potential in the Draft Rules include the following: No solid waste permits would be required. This is not an industrial activity that treats, transfers, stores, processes, or disposes of solid waste. However, a guidance document on water filter backwash solids has criteria for the disposal level criteria for radium. Should there be a need to dispose of solid waste that has radium contained in, the acceptable radium disposal limit is in guidance only. Moving forward, the MPCA could consider adding a rule disposal restriction related to radium levels for any waste generated from the gas industry in the section that lists the industrial waste types that must be addressed in the Industrial Solid Waste Management Plans.9 Rules must be established for any radioactive waste or discharges to the air or water that may occur because of extracting gas created by radioactive decay. In areas where radon concentrations are high, helium concentrations are usually also high, suggesting that both gases use the same fracture systems as preferential routes of leakage.10 Further, the highest concentrations of radon are found in gas-producing zones and show up at higher concentrations as the gas is depleted, evolving from the immediate vicinity of the wells.11 Radon readily reacts with nitrogen (rather than oxygen) upon exposure to air, creating radium nitride, which may adhere to dust or other aerosol particulates to form a surface layer that is hazardous to wildlife and people. Because radon usually shows up later in the extraction processes, it's much harder to manage than other pollutants and should be considered before gas wells are allowed to operate in Minnesota.	Environmental_review	Radioactive materials

463	The assumption that future gas projects won't require solid waste permits relies on the idea that all industrial equipment for separating, processing, storing, and transferring the gas to the market will be kept off-site. But each gas or oil extraction project will likely be different, so unless there is more information that has not been provided in these Draft Rules, there should be a more protective assumption that all gas and oil extraction projects will need Industrial Solid Waste Management Plans that include safe capture, storage, and disposal of all radioactive waste generated.	Health_and_environmental_quality	Need for solid waste permit
464	Flaring waste gas significantly contributes to local air pollution and global greenhouse gas emissions.12 Gas field-produced ozone is a serious air pollution problem in the USA, similar to concentrations found in large urban areas. It can spread up to approximately 200 miles beyond the immediate region where gas is being produced.13 Over 250 toxins have been identified as being released from flaring, including carcinogens such as benzopyrene, benzene, carbon di- sulphide (CS2), carbonyl sulphide (COS), and toluene; metals such as mercury, arsenic, and chromium; sour gas with H2S and SO2; nitrogen oxides (NOx); carbon dioxide (CO2); and methane (CH4), which contributes to greenhouse gases.14 Yet the Recommendations endorse flaring: …where recovery and use of the methane is not feasible, converting the methane to CO2 through flaring may be the next best option. Flaring, sometimes used in managing landfill gases, would also provide the benefit of reducing or eliminating non-methane hydrocarbons, air toxics, and odor causing compounds that may be found at lower concentrations in the well gas and that would otherwise be released to the atmosphere.15 This ignores prevailing science and known health risks. Moreover, flaring will not eliminate radioactive components (e.g. radon gas or radium nitride). Furthermore, to contain fluids produced from flaring of the gas-associated liquid hydrocarbons and brine water, earthen flare pits are constructed beneath the flare stacks. Soil surrounding these pits is typically hydrocarbon and salt-contaminated and mixed with other toxic chemicals that are hazardous to birds and wildlife.16 Yet this risk is also not evaluated.	Health_and_environmental_quality	Flaring
465	Ethane will be released by the Topaz Project, potentially flared off as it converts to methane upon exposure to the atmosphere. Methane is a potent greenhouse gas that must be captured. Methane has an explosive range between 5% and 15% and the concentration of 9.5% is the most dangerous.17 It appears that Pulsar may have concentrations of ethane and/or methane at or near five percent, creating the potential for explosion or fire that must be thoroughly investigated.	Health_and_environmental_quality	Flaring
466	Ethane will be released by the Topaz Project, potentially flared off as it converts to methane upon exposure to the atmosphere. Methane is a potent greenhouse gas that must be captured. Methane has an explosive range between 5% and 15% and the concentration of 9.5% is the most dangerous.17 It appears that Pulsar may have concentrations of ethane and/or methane at or near five percent, creating the potential for explosion or fire that must be thoroughly investigated.	Environmental_review	Carbon and climate change
467	A frequent occurrence resulting from gas extraction is very saline water being pushed to the surface. This can have disastrous impacts on local vegetation and aquatic life that have evolved in conditions with very low concentrations of salt. Freshwater salinization can impact safe drinking water, ecosystem health and biodiversity, infrastructure corrosion, and food production. Freshwater salinization originates from many anthropogenic and geologic sources including mine drainage and gas extraction.18 Minnesota has an unfortunate example to learn from. During the AMAX copper-nickel exploration in 1976, very saline water from 1,371 feet below the surface was contacted, causing the unauthorized discharge of 330,000 gallons to the surrounding surface environment, killing over an acre of vegetation surrounding the drill site.19 At every copper/nickel test drill site where samples were collected, the US Forest Service found saline waters that exceeded the safe drinking water criteria of 250 milligrams per liter of chloride.20 There may also be metals at concentrations that exceed human health in saline water including, but not limited to, barium, strontium, and arsenic. There is a potential need for deep injection wells or other pollution control methods that may be required to protect human health and the environment. Again, an EIS must be mandated for every proposed gas project and it must evaluate the risk of saline water discharges.	Health_and_environmental_quality	Saline water
468	The Recommendations address existing state severance and income taxes.21 While this proposal would require additional development, the Band proposes that a possible means of mitigation of costs and impacts to Ceded Territory resources would be for the state to pay forward to tribes a portion of taxes that the state collects for natural resource extraction.	Tax_distribution	Tax proceeds to Tribes
469	The DNR has recommended a $50,000 application fee for a gas resource development permit and a $75,000 annual permit fee for gas resource development projects, as well as the ability to assess supplemental fees to cover the costs of reviewing an application above the application fee amount.22 We recommend fees for Tribes of an equal amount for review and regulatory oversight within our Ceded Territories.	Gas_production_permitting	Permit fees duplicated to Tribes
470	Gas resource development permits issued under a temporary regulatory framework must be considered truly temporary, expiring once rules for a permanent regulatory framework are promulgated, contrary to MNDNR's current proposal, which is "that the word "temporary" be removed from the phrase 'temporary permit,' to make clear that a permit issued during rulemaking will not be limited to a term less than what is proposed by the applicant, nor revoked once rules are promulgated."23 This is an unnecessary "gift" to Pulsar. Although this rulemaking is being rushed for Pulsar, the company has stated to tribes they haven't finished the exploration stage yet and don't anticipate having a "project" defined for at least another 18 months. We also strongly disagree with the MNDNR's rationale because it potentially allows Pulsar to operate with an advantage over any future companies exploring for helium in MN and allows unmitigated pollution to occur that could adversely impact human and environmental health despite the final rules being adopted.	Gas_production_permitting	Temporary permits
471	The draft further provides that "[t]he risks that a permanent regulatory framework for gas resource development would be dramatically different than a temporary framework might be a strong disincentive to invest in a project if the permittee was forced to reapply for a new 'permanent' permit once rules were promulgated."24 This does not make sense when Pulsar estimates one million dollars per day of expected revenue once operating. There is no disincentive to wait for the final rulemaking other than a desire for lax temporary rules that are less protective of the environment and human health and are less expensive to implement than final rules. Indeed, Pulsar appears so confident that the state will follow its lead that its website (incorrectly) states that "the State of Minnesota passed new helium legislation allowing production to occur from 15 January 2025."25	Gas_production_permitting	Temporary permits
472	Any company proposing a new gas extraction project in Minnesota must be willing to "risk" an update to the permit as soon as final rulemaking has occurred. Pulsar knows it is taking a risk by developing plans before rulemaking has been completed and should expect to be able to operate under a temporary permit only until the rules are finalized, in compliance with the Legislature's desire for a viable mechanism to enable gas resource development project permitting during rulemaking without providing an improper advantage to a specific company.	Gas_production_permitting	Temporary permits

473	The DNR recommends that a person applying for a pooling order control at least 50 percent of the mineral interests within an established spacing unit. We do not think 50 percent ownership of mineral interests is enough for a pooling order. We recommend a minimum of a 75 percent interest requirement for pooling. The MNDNR recommends that the operator of wells under a pooling order in which there is a nonconsenting owner furnish the nonconsenting owner with a monthly statement of all costs incurred, together with the quantity of gas produced, and the amount of proceeds realized from the sale of production during the preceding month. This is a good recommendation—but only if the pooling order is provided when there is at least 75 percent ownership of the mineral estate. 50 percent provides an unfair advantage to the rights holder who wants to develop gas if their neighbor has other plans that may not be conducive to gas wells.	Pooling_orders	% of owner consent
474	This goes to the need for an equitable provision of information, especially given the unknowns of the resource. Currently, the MNDNR requires relatively limited information disclosure: Until more information is available about the nature and extent of Minnesota's gas resources, the DNR recommends that gas resource development permittees submit to the commissioner, as a permit condition, a pre-production report that includes the engineering and geological data obtained from any gas wells drilled as part of their project (whether or not the permittee plans to take a gas well into production). The report must compare the hard data obtained from their gas wells against any estimates submitted to the commission before drilling. The commissioner will use the data to evaluate potential changes to an established spacing unit or pool unit and consider the potential impacts of bringing the project into production.26 The Band asks that this information must be simultaneously provided to the tribes.	Data_sharing_public_data	Pre-production report should go to Tribes
475	Finally, although the DNR "recommends" that unleased mineral interests tied to an American Indian tribe or band owning reservation lands in Minnesota should be shielded by state law from state-issued pooling orders, we believe that state law should prohibit pooling within any tribe's reservation boundaries regardless of surface or subsurface ownership. This recommendation is for both the temporary and post-rulemaking regulatory frameworks. At the same time, the Band reiterates that tribes reserve all their rights under tribal and federal law, and in no way concede that the state may unilaterally authorize gas exploration activity within their lands.	Pooling_orders	Shielding from pooling orders
476	Siting could be a huge issue that may collide with the wants and needs of non-ferrous mining proposals moving forward: Legislation passed in May 2024 requires the commissioner to develop rules for siting gas resource development projects (93.514). Gas resource development locations need to be at sites that minimize adverse impacts on natural resources and the public, with setbacks or separations that are needed to comply with environmental standards, local land use regulations, and requirements of other appropriate authorities."27 Siting should be assessed in an EIS.	Environmental_review	Siting and setbacks
477	We do not agree that the MNDNR is the natural fit for serving as the RGU because they do not have the greatest responsibility for supervising or approving the project as a whole. Instead, we recommend that MPCA become the RGU for gas extraction projects because they are the agency tasked with the most regulatory oversight, including wastewater permits, industrial stormwater permits, construction stormwater permits, air quality permits, storage tank regulation and permitting, and solid waste permitting. Along with MDH, MPCA authorities are tied to protecting human health and the environment. When the state is leasing mineral rights, MNDNR has pooling, spacing, siting, financial assurance, and reclamation for the extraction of gas. In the case of private minerals on private or federal lands, the MNDNR is only assigned to ensure that the projects do not extract resources they do not own or lease and that closure plans that protect and maintain the surface are followed. In either case, state-leased or privately held minerals, MPCA has more regulatory authorities than the MNDNR and, therefore, should be considered the RGU.	Environmental_review	MPCA should be RGU
478	We agree that corporate guarantees are worth no more than the paper they are written on, and the State must have much more robust tools for financial assurance for gas projects. Financial assurances are a source of funds to be used if the permittee fails to perform, with additional language we propose indicated by underlines: • Reclamation activities including closure and post-closure maintenance needed if operations cease; and • Corrective action as required by the MPCA and the MNDNR if noncompliance with engineering design and operating criteria occurs; and • To ensure that other natural resources are not damaged or can be repaired or mitigated using financial assurance instead of taxpayer revenue.	Financial_assurance	FA structure
479	Furthermore, the state should not allow money collected as part of financial assurance for gas resource development projects to be invested by the State Board of Investment unless there is a requirement to supplement any funds that are diminished by investment to their original amount. If investment yields generate more money, that is helpful. However, if the investments decrease the amount of financial assurance a company has provided, there may not be enough funds to deal with the work that is needed. Therefore, interest-bearing accounts must be very conservative in nature to ensure no loss of funds.	Financial_assurance	SBI investment of FA
480	The agencies represented on the GTAC did not consult with Tribes as required by law. Instead, the MNDNR simply provided informational updates. Tribal interests have not been addressed. Stating that the Legislature gave the MNDNR a very short time to define the members of the GTAC and draft the temporary rules is not an excuse for ignoring the requirements of Minn. Stat. Sec. 10.65, which apply to all state agencies and actions that affect tribes.	Tribal_relations	Need for consultation
482	EQB-1, establishing a new mandatory category for environmental review and designating the DNR as the responsible governmental unit (RGU). While we agree that this new type of industrial development should be subject to a new mandatory environmental review category, we strongly advocate for the EQB to require a full environmental impact statement (EIS). This is the appropriate approach for an industry that does have the potential for significant environmental effects, alongside the state's complete lack of experience in regulating, mitigating and enforcing compliance on gas development projects. An EIS has more requirements for analyses and alternatives, mitigation of adverse environmental and human health effects (including the toxic and carcinogenic effects from radioactive compounds or elements), cumulative impacts, environmental justice, greater public involvement, and tribal consultation.	Environmental_review	Tribal consultation within ER
483	Recommendation EQB-1 requires a mandatory EAW for any gas resource development project, with Department of Natural Resources as the Responsible Government Unit (RGU). This is absolutely inadequate, especially for the development of a temporary regulatory framework for an industry that has never before existed in the state. Because of the new nature of the industry to Minnesota, and the unexplored environmental risks such as radioactive materials related to gas production, an EIS is needed for all gas projects under the temporary framework and likely under permanent rules as well. The EQB has previously talked about the importance of equitable treatment and providing Tribes the opportunity to engage in projects and regulation. The only way to guarantee this equitable treatment and to allow Tribal participation is to require an EIS for all gas projects.	Environmental_review	Tribal consultation within ER

484	An Environmental Impact Statement (EIS) should be mandated for all gas projects due to the potential for significant environmental effects, including the release of radioactive and toxic substances like radium isotopes, radon, and radium nitride. Radium-226, the most stable isotope of radium, is a key concern. It is the final isotope in the (4n + 2) decay chain of uranium-238, with a half-life of 1,600 years, and constitutes nearly all naturally occurring radium. Its immediate decay product, radon, is 2.7 million times more radioactive than the same molar amount of natural uranium due to its shorter half-life. Additionally, radium reacts with nitrogen in the air to form radium nitride (Ra3N2), a solid black compound, further demonstrating its hazardous nature. Unlike an Environmental Assessment (EA), an EIS has stricter requirements to assess methods for reducing environmental and human health risks, including cumulative effects. It also involves greater public scrutiny, consultation with Tribal leaders, and reviews by Tribal Historic Preservation Officers. The draft rules indicate that thresholds for requiring an EAW {Environmental Assessment Worksheet) or an EIS are based on project size, with smaller projects triggering an EAW and larger ones requiring an EIS. However, the specific size thresholds are not disclosed. According to the draft, gas wells typically have a ten-acre footprint. However, Pulsar, a company involved in these projects, has suggested its direct footprint will be five times larger, covering approximately SO acres. Pulsar currently holds surface rights to over 4,181 acres, indicating the potential for a significantly larger overall project scale.	Environmental_review	Tribal consultation within ER
485	Public Health Considerations: Any risks posed to surrounding communities, especially those that rely on local water sources or live in close proximity to extraction sites, must be assessed. The release of contaminants, the risk of radon exposure, and the potential for other health impacts must be thoroughly evaluated in an EIS. An EIS would not only ensure compliance with environmental laws and regulations but also provide transparency, allowing for a broader public discussion about the environmental and health consequences of helium extraction. This process would allow stakeholders, including local communities, tribal nations, and environmental groups, to provide input and ensure that the potential risks associated with this activity are carefully evaluated and addressed before any extraction takes place.	Environmental_review	Tribal consultation within ER
486	The proposed framework also recommends that an Environmental Assessment Worksheet (EAW) be prepared for projects. This is not a sufficient environmental review process, as EAWs are used for projects anticipated to have less significant and shorter impacts on the environment. This again feels like "fast tracking" projects without the necessary review process. An Environmental Impact Statement (EIS) should be required to fully understand impacts from a project. Tribal consultation is also needed during the environmental review process, and an EIS would better provide that opportunity.	Environmental_review	Tribal consultation within ER
487	An Environmental Impact Statement (EIS) has more requirements than an Environmental Assessment (EA) to explore methods to reduce adverse environmental and human health effects, including cumulative effects, requires more public evaluation and consultation with Tribal leaders, and includes reviews by Tribal Historic Preservation Officers.	Environmental_review	Tribal consultation within ER

Table: Considerations of thematic input received on GTAC draft recommendations and statutory language

Theme	Subtheme	Consideration
Health and environmental quality	Worker safety	In Minnesota, worker health and safety issues are regulated by the Department of Labor and Industry. Gas resource development does not involve underground mines and underground mine workers, and blowout prevention systems on gas rigs mitigate the risk to rig workers of uncontrolled releases of high-pressure gas. Heavier-than-air gases, such as carbon dioxide or methane, are only a potential health risk if they are concentrated within enclosed spaces. Venting of these gases should be regulated as greenhouse gases but would otherwise not warrant adjusting gas well setbacks beyond those proposed by the MDH and DNR.
Health and environmental quality	Flaring	It is known that well gas can contain methane and carbon dioxide (CO2) (approximately 2.5% and 68%, respectively) which are greenhouse gases. Therefore, the MPCA may consider regulating those gases to minimize their release to the atmosphere through carbon sequestration or maximize their beneficial use through capture and recovery. Where that is not feasible, converting the methane to CO2 through flaring may be the next best option (flaring can provide the benefit of reducing or eliminating non-methane hydrocarbons, air toxics, and odor causing compounds that may be found at lower concentrations in the well gas and that would otherwise be released to the atmosphere). Should MPCA decide to regulate greenhouse gases, it would proceed through the rulemaking process.
Health and environmental quality	Saline water	Comments received express concerns over saline water within a gas well. These waters may contain dissolved minerals, including metals, which if discharged to the surface could negatively impact surrounding vegetation and drinking water. Existing regulation for wells and borings requires disposal of discharge water according to federal, state, and local requirements. MDH recommends for gas wells a similar requirement for discharge waters from drilling to be containerized and disposed of off-site according to federal, state, and local requirements. Any injection of wastes into the gas well would require a Class 2 injection well permit, as authorized by the EPA, per MDH's recommendations.
Health and environmental quality	Hydraulic fracturing	GTAC received comments on hydraulic fracturing of gas wells agreeing with a prohibition and others recommending authorization while being protective of public health. MDH has reviewed and considered this input. MDH intends to move forward with the recommendation to prohibit hydraulic fracturing of gas wells but will consider authorization of hydraulic fracturing through rulemaking.
Health and environmental quality	Class II injection wells	GTAC has reviewed input that recommended consideration for Hydrogen and use of a Class 5 injection well approved by the EPA. Other recommendations discussed the environmental review process and needs for permitting. GTAC is responding to recommendations specific to Helium. MDH will consider extraction and production specifications for Hydrogen during the rulemaking process.

Theme	Subtheme	Consideration
		Environmental review is meant to inform government decisions (i.e., permits). An EAW is utilized by projects which may have the potential for significant environmental effects to identify if those projects based on their nature and location will actually have significant environmental effects and therefore require additional analysis in an EIS. EQB staff believe that for the temporary regulatory framework it is appropriate to require an EAW for all gas development projects, recognizing that any projects of this type may have the potential for significant environmental effects. The EAW form has a list of 22 questions that are meant to prompt the Responsible Governmental Unit in analyzing and determining potential environmental effects from a project. The RGU is responsible for determining and analyzing whether any potential environmental impact from a project may result in a significant environmental effect and require an EIS or evaluate if mitigation is available to alleviate those impacts and in term use that information to inform future permit decisions. An operator would need to secure all necessary permits from all relevant agencies, prior to permitted operations.
Health and environmental quality	Violation fines	DNR has recommended statutory language for permitting gas resource development projects that would allow the commissioner of natural recourses to deny, suspend, revoke, or modify a permit or assess civil penalties if a permittee fails to comply with permit requirements that minimize waste and protect human health and the environment. DNR was given rulemaking authority over permitting and reclamation of gas resource development projects. The magnitude of assessed civil penalties and how they are determined would be a rulemaking topic, and the rulemaking process provides opportunities for public review and comment.
Financial Assurance	FA Structure	DNR has considered the input provided on the structure of Financial Assurance for gas projects. We are developing a Financial Assurance program within the broader framework of Minnesota's laws, its constitution, and environmental and permitting regulations to ensure that this natural resource development within the state is protective of human health and the environment. Gas projects will vary in size and scope, timeframe, and potential impacts, as will the Financial Assurance instruments used for each gas project.
Financial Assurance	SBI investment	We appreciate the input on SBI Investment. DNR considered the input linked to this subtheme, as well as many requests for a robust Financial Assurance program with regulatory oversight, and consideration of regulations in other states. SBI Investment instruments will correlate to the timeframe of the individual gas project, to ensure sufficient funds are readily available.
Process	There should be no temporary framework	GTAC carefully reviewed the received input that argued against creating a temporary framework for permitting gas development during rulemaking. The state legislature created GTAC and gave it a mandate to make recommendations on how such a temporary regulatory framework could be constructed. Decisions on whether those recommendations should be acted upon are not GTAC's to make, and are instead reserved for the state legislature. Should the state legislature draft a bill that is based on GTAC's recommendations, there would be legislative committee hearings and opportunities for public comment.

Theme	Subtheme	Consideration
Process	Permits before full understanding	Input considered. Recommendation DNR-11 only applies to the temporary because they will be replaced by rules promulgated for a permanent regulatory framework. Consideration of the "There should be no temporary regulatory framework" is also relevant here.
Process	Poor track record	Input considered. Thank you for your submission.
Process	Burdensome regulations	DNR considered the input that qualified for the "Burdensome regulations" subtheme and understands the concerns expressed. DNR believes that the legislative intent behind creating a temporary regulatory framework includes not just permitting during rulemaking, but also the possibility of production. Our regulations and permit decisions need to fit within the broader framework of Minnesota's laws and state constitution. Permits issued under a laissez-faire type of regulatory framework, or a framework that is modeled after regulations in states that don't have laws like MEPA or MERA, would likely face lengthy court challenges and (literally) counterproductive delays. Permit decisions based on the environmental review of a project that already has most of its infrastructure already in place (e.g., gas wells and drill pads) would similarly be ripe for litigation. That said, many of the concerns about burdensome regulations focused on the costs and time required for permitting before any kind of subsurface exploration could occur. The MDH decision to allow for gas exploration using exploratory borings that wouldn't require permitting or environmental review should alleviate at least some of those concerns.
Process	Ethics standards	GTAC considered the input on ethics standards, and the suggestion that state employes who developed rules for a regulated industry be barred from working in that industry after they leave public service. This idea is outside of GTAC's purview.
Process	DNR conflicts of interest	DNR considered the piece of input tied to this subtheme. When DNR is the RGU, environment review is completed by the Environmental Review unit, which is part of the Division of Ecological and Water Resources. Regulatory oversight and permitting for mineral resource development is delegated to the Lands and Minerals Division. That said, it is the commissioner of natural resources (who oversees these two divisions) that makes final decisions about level of environmental review and permit issuance.
Process	Consumption patterns	The DNR considered this public input, and thanks the submitter for offering it. While the consideration of consumption patterns and societal decisions about natural resource development are incredibly important, they sit outside of GTAC's purview.
Process	Timing of resource extraction	DNR considered input that urged facilitating gas production, given the current need for gas resources such as helium, and input urging caution on developing resources that might be far more critical for future generations

Theme	Subtheme	Consideration
		to use. DNR believes that decisions about the timing of resource extraction are policy matters, best handled through consideration by the Minnesota Legislature.
Process	Need underground gas storage framework	GTAC agrees that Minnesota lacks a regulatory framework for greenhouse gases and underground storage or sequestration of gases such as carbon dioxide. Developing recommendations on how such a framework might be constructed would be the work of a different technical advisory committee. For example, states that have developed a framework for permitting carbon storage projects have sought Class VI well program primacy from USEPA so that they can issue carbon injection well permits locally at the state level rather than federally via the United States Environmental Protection Agency. We would anticipate the idea of Minnesota similarly seeking program primacy would be an item of high priority to discuss and/or implement on that other technical committee's list of recommendations.
Process	Robust regulation	DNR considered the input linked to this subtheme, as well as the calls for robust regulatory oversight and consideration of the regulations in other states that are reflected in input within other subthemes. DNR's recommendations for gas resource development permits and regulatory oversight were developed within the broader framework of Minnesota's laws, its constitution, and environmental regulations that ensure that any type of natural resource development within the state is protective of human health and the environment. These considerations have, in some instances, led GTAC to recommend a temporary regulatory framework that deviates from the "standard practices" used to regulate gas development in other states.
Process	Contested case and legal	The requirements for a contested case in section 93.5176 are identical to the contested case provisions for the permit to mine under section 93.483. To clarify, only the first two items of the petition contents are required, and the additional items must only be addressed to the extent known by the petitioner. The proposed contested case hearing process is limited to persons owning property that will be affected by an operation, and federal, state, and local governments that have responsibilities that will be affected by an operation. The existing language is intended to balance permitting efficiency with the opportunity for persons to appeal permitting decisions that impact them.
Process	Leasing	While the minimum royalty rate for oil and gas leases on state-managed mineral was set by the legislature in the same enabling legislation that formed GTAC, recommendations on whether that royalty rate is appropriate fall outside of GTAC's focus on a temporary regulatory framework. **CHANGE:** The enabling legislation that authorized DNR to issue oil and gas leasing on state lands did not give DNR expedited rulemaking authority to write rules for an oil and gas lease program. DNR is revising its

Theme	Subtheme	Consideration
		recommendation on amending 93.514 (a) (4), and is now requesting that oil and gas leases be added to the list of topics that DNR must develop rules for under expedited rulemaking.
Process	Statutory language	GTAC appreciates some commentors providing specific edits needed within the statutory language. We have considered those edits and make them where necessary.
Process	General	GTAC appreciates the input about offering public meetings, understands the economic potential of gas resource development, and the concerns about long permitting process discouraging explorer interest. Permit issuance under temporary framework requires legislative action, and 2025 legislative session ends in May. DNR is unaware of plans to construct a helium pipeline; truck transport is anticipated. GTAC appreciates the submission of industry terminology and definitions and comparable regulations from other states for consideration. GTAC understands perhaps better than anyone that there were unavoidable time constraints for both reviewing the draft recommendations and creating them.
Tribal relations	Need for consultation	The DNR has provided gas leasing and regulatory legislation updates to the tribal government environmental staff at the State/Tribal mining meetings. These updates started in April during the 2024 legislative session and have occurred at every meeting since. The Gas Resources Technical Advisory Committee (GTAC) members were present at the October 8, 2024, State/Tribal mining meeting. This was an announced agenda topic, and tribal technical staff were encouraged to bring others who may have questions for the GTAC team. On November 13, 2024, the DNR held a meeting with Tribal Leadership from all the 11 recognized Tribal Governments. DNR Commissioner Strommen discussed the legislative directive and DNR technical leads walked tribal leaders through the GTAC process and what they could expect to see when GTAC would send the draft recommendations and statutory language to tribes on November 15, 2024. The tribes received the draft recommendations and statutory language on November 15, 2024, which was two weeks prior to the public review. Tribes were allowed to submit comments during their early review period and/or during the public input period that started on December 2, 2024, and ran through December 23, 2024. Prior to the input period, tribal leaders did not call for Consultation regarding gas legislation or the GTAC recommendations in the State.
Tribal relations	Usufructuary rights	The Tribes retain usufructuary rights to hunt, fish and gather within certain Ceded Territories as provided by Federal Treaty. None of those treaties expressly reserve mineral or gas rights and the DNR is unaware of any case recognizing off reservation usufructuary rights to gas or mineral within the ceded territories in Minnesota.
Tribal relations	Introduction/context	GTAC appreciates the input received from Tribal governments.

Theme	Subtheme	Consideration
Tribal relations	Summary of themes covered	GTAC acknowledges the input received from Tribal governments and recognizes that some letters approach the conclusion by summarizing the key arguments made throughout the letter. These summary paragraphs were not tagged under the specific topic area.
Environmental Review	Need for comprehensive EIS	The Environmental Assessment Worksheet (EAW) process is used to review a project that may have the potential for significant environmental effects. An Environmental Impact Statement (EIS) is the process for reviewing a project that does have the potential for significant environmental effects. EQB staff believe that for the temporary regulatory framework it is appropriate to require an EAW for all gas development projects, recognizing that any projects of this type may have the potential for significant environmental effects. A gas development project may have the potential for significant environmental effects relating to air quality, land use, transportation, noise, and water quality. Gas production and extraction projects are new in Minnesota, a mandatory EAW creates opportunities for governmental units to learn about potential impacts from these projects. As a reminder the purpose of an EAW is to decide if an EIS is required. The mandatory EAW process allows the RGU to determine if the nature and location of a particular project requires further analysis of environmental effects through an EIS.
Environmental Review	Tribal consultation within ER	EQB is interested in incorporating Tribal involvement within environmental review program wide. Given that the EQB determination is for a gas resource development project be preceded by a mandatory EAW, the EQB has added an additional recommendation that would require Minnesota Tribal governments to receive notice of any EAW publication and notification for a gas resource development project. Section 10.65 identifies the need for certain state agencies to define when those state agencies must coordinate and consult with Minnesota Tribal governments. EQB does not have the authority to define when agencies must consult with Tribal governments but strongly supports including Tribal governments early in the environmental review process for gas resource development projects. Additionally, the RGU proposed for gas resource development projects (DNR) is a state agency with a tribal consultation policy that DNR must follow in any actions it takes, which would include environmental review projects.
Environmental Review	No mandatory EAW for exploration	MDH has added additional recommendations regarding exploratory borings for gas. These recommendations would allow for exploration but would prohibit the production of gas from an exploratory boring. These recommendations would follow the current process for exploratory borings which does not have a governmental action tied to it and therefore environmental review would then take place after the exploration phase is completed and a permit from the DNR is requested.
Environmental Review	MPCA should be RGU	Responsible governmental unit (RGU) selection for when two or more units of government have jurisdiction to approve a project is addressed in MR 4410.0500, which identifies that the unit of government with the greatest responsibility for supervising or approving the project as whole should serve as the RGU. The EQB recognizes

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		the “gas resource development permit” being proposed by the DNR to represent the action which constitutes the supervision or approval of a gas extraction/production project as a whole. EQB has added an additional recommendation that serves as a reminder that environmental review is meant to be a collaborative process and meant to inform all decisions regarding a project and would therefore recommend the RGU to incorporate collaboration from all governmental units with regulatory authority over a gas resource development project when completing environmental review for a project.
Environmental Review	General	Minnesota’s environmental review program designates when certain project types must undergo environmental review and what type of environmental review those projects must undergo. The program also designates a single responsible governmental unit but does encourage collaboration amongst other units of government to eliminate duplication and to achieve the best understanding of potential effects from a project. The recommendation for gas resource development projects is for any size project that requires a gas resource development permit from the DNR to undergo a mandatory EAW process. The RGU then is responsible for completing that process for which an EAW is meant to identify the need for an EIS. This process does not preclude a project proposer from initiating the environmental review process via consultants. The rules indicate that a project proposer must provide data concerning the project to the RGU. In practice it is most common for RGU’s to receive data via a completed EAW form. The RGU is then responsible for reviewing the data received and making a determination if the submittal is complete and ready for publication or not.
Environmental Review	Need for baseline data	The recommendations for a programmatic assessment of Minnesota gas resources are something that could likely be achieved via a GEIS. A generic EIS could offer an opportunity to learn more about the environmental impacts of gas resource development projects and utilize that information in developing future environmental review requirements moving forward such as other GEIS’s that have been completed in the past as well as provide useful information to future project proposers and the RGU in better understanding potential impacts. However, the pursuit of a GEIS would require funding from the legislature for the EQB to pursue.
Environmental Review	Need to define mandatory category thresholds	The threshold for requiring environmental review during the temporary framework is that any project requiring a permit from the DNR for a gas resource development to be proceeded by a mandatory EAW. For the development of the permanent framework the EQB will have an opportunity to incorporate information learned from any environmental review that is completed utilizing the temporary framework. This information may be helpful in evaluating the needs for whether projects intending to produce gas resources should have different environmental review thresholds (i.e., exemptions, EAW and EIS thresholds, EAW and EIS thresholds for different gas resource types).

Theme	Subtheme	Consideration
Environmental Review	EAW & EIS costs	MR 4410.6000 - 4410.6500 identify the ways for which RGUs are to assess and recoup costs from a project proposer for the preparation and completion of the EIS process. EQB rules neither permit nor prohibit RGUs from assessing costs related to development of EAWs. The EQB website provides guidance and information/examples to local units of government on how to write policies and ordinances at the local level regarding EAWs. This guidance does include examples that would allow for the ability to recoup costs from completing the EAW process. State agencies have typically borne the costs of EAWs, although there are mechanisms for costs associated with environmental review to be recouped by state agencies for projects that involve new, complex, or controversial projects with certain characteristics. For example, projects that involve large water appropriations and also require environmental review can recoup certain costs associated with that review such as those consistent with Minnesota Statutes 103G.301 Subd2(b). Projects that involve new industries to Minnesota, such as gas exploration, should expect that until the potential impacts are well understood, they will be subject to an increased level of scrutiny requiring collection of new information about the technologies and industry where those costs could be borne by proposers. As projects come forward and the understanding about impacts increases, the challenges of dealing with new issues should decline and thus the need for some measure of cost reimbursement should decline as well. Multiple EAWs can be managed by DNR project managers, so at estimate of 0.3 FTE would be assessed per EAW. While the rules provide specific details regarding fees and costs for preparing Environmental Impact Statements (EISs), they do not outline similar procedures for preparing EAWs. It is important that local governments establish procedures and fees for preparing and reviewing EAWs and utilize their local ordinances to support these procedures.
Environmental Review	Siting and setbacks	Environmental review is meant to inform government decisions (i.e., permits). The EAW form has a list of 22 questions that are meant to prompt the Responsible Governmental Unit in analyzing and determining potential environmental effects from a project. The RGU is responsible for determining and analyzing whether any potential environmental impact may result in a significant environmental effect or evaluate if mitigation is available to alleviate those impacts and in term use that information to inform future permit decisions.
Environmental Review	Alternative site analysis	Environmental review is meant to inform government decisions (i.e., permits). An EAW is utilized by projects which may have the potential for significant environmental effects to identify if those projects based on their nature and location will actually have significant environmental effects and therefore require additional analysis in an EIS. The EAW form has a list of 22 questions that are meant to prompt the Responsible Governmental Unit in analyzing and determining potential environmental effects from a project. The RGU is

Theme	Subtheme	Consideration
		responsible for determining and analyzing whether any potential environmental impact from a project may result in a significant environmental effect and require an EIS or evaluate if mitigation is available to alleviate those impacts and in term use that information to inform future permit decisions.
Environmental Review	Radioactive materials	GTAC appreciates expressed concerns about links between helium production and the release of radioactive materials. Helium is generated through radioactive decay of elements such as uranium and thorium. These radioactive elements exist in solid form and in trace quantities within the crystalline structures of minerals found mostly within granitic rocks that are located within the Earth's crust. When these solid radioactive particles decay, they generate helium gas. The remaining radioactive particles remain in solid form, and if that rock is heated to a temperature that releases the helium gas, the solid radioactive particles remain behind. So while it is true that helium is born from radioactive decay, the helium gas itself is not radioactive, and no radioactive material is carried by the helium gas as it rises through the Earth's crust to locations where it can be extracted for human use.
Environmental Review	Environmental impacts	Environmental review is meant to inform government decisions (i.e., permits). An EAW is utilized by projects which may have the potential for significant environmental effects to identify if those projects based on their nature and location will actually have significant environmental effects and therefore require additional analysis in an EIS. The EAW form has a list of 22 questions that are meant to prompt the Responsible Governmental Unit in analyzing and determining potential environmental effects from a project. The RGU is responsible for determining and analyzing whether any potential environmental impact from a project may result in a significant environmental effect and require an EIS or evaluate if mitigation is available to alleviate those impacts and in term use that information to inform future permit decisions.
Environmental Review	Carbon and climate change	The ER related response for carbon and climate change would be the same as other responses to ER questions regarding environmental concerns about a gas project. Otherwise, the rest of this section should be forwarded to MPCA. MPCA is considering regulating greenhouse gases (e.g., CO_2 and CH_4) and recognizes carbon sequestration and requirements for capture and recovery as methods for controlling the release of greenhouse gases to the atmosphere. Should the MPCA decide to proceed with greenhouse gas regulation, it will follow through the rulemaking process. Further, environmental review is another informational tool the MPCA could use to inform the regulatory process.

Theme	Subtheme	Consideration
Environmental Review	Traffic and roads	Environmental review is meant to inform government decisions (i.e., permits). The EAW form has a list of 22 questions that are meant to prompt the Responsible Governmental Unit in analyzing and determining potential environmental effects from a project. Traffic has a section of questions on the EAW form. The RGU is responsible for analyzing whether traffic (any environmental impact) may result in a significant environmental effect or evaluate if mitigation is available to alleviate those impacts and in term use that information to inform future permit decisions. When EAW's are published it includes a public comment period which offers the public an opportunity to participate in the environmental review process and raise specific concerns regarding specific projects.
Environmental Review	Noise / light	Environmental review is meant to inform government decisions (i.e., permits). The EAW form has a list of 22 questions that are meant to prompt the Responsible Governmental Unit in analyzing and determining potential environmental effects from a project. Visual and noise each have sections of questions on the EAW form. The RGU is responsible for analyzing whether noise, light (any environmental impact) may result in a significant environmental effect or evaluate if mitigation is available to alleviate those impacts and in term use that information to inform future permit decisions. When EAW's are published it includes a public comment period which offers the public an opportunity to participate in the environmental review process and raise specific concerns regarding specific projects.
Pooling Orders	Shielding from pooling orders	DNR carefully considered the suggestion offered by many of the Tribes that the State should go further than federal law with respect to shielding unleased federal and Tribal lands from state pooling orders, and exclude all unleased mineral interests within established reservation boundaries, regardless of whether they are Tribally-owned. For consistency, DNR believes that it is appropriate for the state to align its laws on shielding unleased Tribal lands from state pooling orders with Federal law. Action: The USFS suggested that the draft GTAC recommendations and statutory language incorrectly implied that the state has authority to manage mineral interests owned by the U.S. government. DNR has revised the language within DNR-28 to make clear that this recommendation does not assume or imply this authority. The USFS also recommended that GTAC establish setback distances to prevent "line drilling;" the DNR believes that setback distances from property lines are unnecessary under the system of spacing units and pooling orders that it has recommended be adopted.
Pooling Orders	% of owner consent	The DNR has reviewed the pooling and spacing regulations in 36 U.S. states with oil and gas resources. Thirty-two of the 36 states (89%) do not require a pooling order applicant to own or control any mineral interests within a spacing unit (i.e., the threshold is 0%). There are four states that do an application threshold greater than zero percent (Colorado, Tennessee, Kentucky and Idaho). These minimum control percentages range from

Theme	Subtheme	Consideration
		45% to 55%. The recommended threshold of 50% control for a pooling order in Minnesota would be within that relatively tight range. There are six states that do not have a threshold requirement to apply for or request a pooling order, but instead have threshold requirements for approval of a proposed pooling order by those persons who control production rights within a spacing unit and/or persons with a royalty interest within a spacing unit. The DNR believes that it is better to require evidence of controlled ownership interests within a spacing unit (and implied approval) before a pooling order application is accepted, rather than afterwards.
Pooling Orders	Agency authority	One received comment, while agreeing that a commissioner should have the authority to issue pooling orders, suggested that it should be the MPCA commissioner that holds that authority, rather than the DNR commissioner. The state legislature directed the DNR commissioner to develop rules for pooling and spacing this past spring (93.514 (a)(4)).
Pooling Orders	Application process	There were three comments relating to the application process for a state-issued pooling order (outside of percentage control thresholds). DNR agrees that establishing clear expectations for application fees will provide stability, and that transparency and fairness during the application process are critical for supporting the correlative interests of nonconsenting landowners. As for the suggestion that a pooling order applicant must disclose their gas exploration results, DNR notes that a spacing unit needs to be established prior to a pooling order application, and that a spacing order applicant has to provide an operating plan and evidence that the proposed spacing unit represents the maximum extent of gas resources that can be efficiently and effectively developed by their well or wells.
Pooling Orders	Compensation for nonconsenting owners	Input on how nonconsenting owners are compensated under a pooling order touched on several different subtopics. It was suggested that a nonconsenting owner receive more than their proportionate share of the profits from production, to compensate for lost opportunities to develop their share of the resource in the future when prices might be higher. On the other hand, it was also suggested that the solution to nonconsenting owners is that, “the unwilling party should simply be excluded from the (spacing unit) designation.” DNR understands the concerns about nonconsenting owners responsibility (should a well prove profitable) to pay their share of drilling costs that they had no control over. That said, the process of nonconsenting owners having their share of drilling and equipment costs repaid to the voluntary parties (while they still get 18 ¾% portions of their share of profits) is integral to the pooling process. One commenter suggested that the lien on a nonconsenting owners’ share of profits should be fully paid before they start to receive their share of production profits. DNR believes that providing nonconsenting owners a smaller 18 ¾% share of their share of profits from the start, while at the same time levying a risk penalty to the amount paid from the remainder, balances the correlative interests of both consenting and nonconsenting owners. Finally,

Theme	Subtheme	Consideration
		DNR acknowledges that that a statutory royalty rate of 1/8th (12.5%) for nonconsenting owners is used in several other states. At least some of those rates were set decades ago, when a 12.5% royalty rate was common for private landowner leases, and the royalty rate for federal public lands was 12% up until a few years ago. However, the state legislature set also set a minimum royalty rate of 18 ¾% for oil and gas leases on state-managed mineral interests, and believes that this higher royalty rate is closer to the rates currently used for oil and gas leases.
Pooling Orders	Rights of nonconsenting owners	DNR carefully considered input tied to the rights of nonconsenting owners (and related input that has been grouped under the subtheme "compensation for nonconsenting owners." DNR agrees that the mineral estate is dominant over surface estate, but in the case of nonconsenting owners believes that it is not unreasonable to shield nonconsenting owners from gas development operations on their surface lands. This provision is found in the pooling order statutes in Colorado and other oil and gas jurisdictions. As for the suggestion that nonconsenting owners receive monthly statements on production, profits and expenses every 90 days, rather than 60, DNR understands that the realities of operational expenses and monthly accountings, but notes that monthly states are a common requirement in the pooling laws in other states, and that monthly statements are required by the state of Minnesota for operators holding metallic mineral leases on state-owned mineral interests.
Pooling Orders	General	DNR considered the wide variety of general comments about the recommended pooling order process. Some of the proposed statutory language for pooling orders was changed after an internal legal review better aligned our recommendation with Minnesota's legal framework. Statutory language establishing the right of landowners to voluntarily pool their mineral interests is embodied within the laws of several other states, in some cases with the additional comment that this cooperative effort does not violate the state's anti-trust or anti-competitive behavior laws. DNR agrees with belief that lease language that asserts a right to be pooled on an adjacent lease is inconsistent with the protection of correlative interests and believes that the recommend process for establishing spacing units and issuing pooling orders addresses the issue. Concerns that prohibiting gas well drilling within a spacing unit while a pooling order application is considered were considered and are partially addressed by revisions made by MDH on the use of exploratory borings for gas exploration. In addition, DNR notes that this proposed provision mirrors pooling statutes in other states.
Pooling Orders & Spacing Unit	Legal challenge process	The contested case hearing process that is proposed for pooling orders follows established procedures in the state of Minnesota, that would protect the rights of the parties. The proposed process includes certain exclusions from involuntary pooling orders, which effectively shields mineral interests controlled by Tribes from involuntary pooling but focus on the ownership of mineral interests, not land ownership. Tribes have the opportunity to voluntarily pool their mineral interests if they choose to do so.

Theme	Subtheme	Consideration
		Regarding the timing of challenges to pooling and spacing orders: for pooling orders, certain parties can request a contested case hearing to challenge a draft pooling order. For spacing orders, DNR is not proposing a contested case process because spacing orders have less financial impact on mineral owners than pooling orders. DNR is proposing that spacing orders are directly appealable to the court of appeals, and the proposed language allows both operators and interested parties to apply to modify a spacing unit. Even if no appeal provisions were included in the statutory language, pooling and spacing orders issued by DNR would likely be appealable pursuant to Minnesota Statutes chapter 606.
Spacing Units	Application process	The input on spacing unit application procedures was considered.
Spacing Units	Size and shape	State-wide rules that automatically set a spacing unit with a fixed size and shape (e.g., square-shaped and 160 acres) are used by some oil and gas producing states, particularly in unproven areas. That method works best for “traditional” pancake-shaped oil and gas reservoirs within porous and permeable rock formations. In contrast, DNR understands that the only currently known gas resource in the state is thought to be fracture controlled. It is far more likely that gas resources within networks of fractures will have an irregular shape and size (i.e., more pencil than pancake). Square-shaped spacing units with fixed acreage would not protect the correlative interests of landowners in this situation…far better to have an operator propose a reservoir-specific spacing unit whose size and shape reflects the size and shape of the resource, based on available data, and for the DNR to make a final decision based on its own evaluation of the data presented by the applicant. Finally, a recent technical evaluation of the Pulsar Helium project estimates the resource drainage area to range from 80 to 640 acre in size, with a “best” value of 223 acres (AIM Admission Document (October 2024), page 89). Since this is likely the only project to apply for a spacing unit under the temporary regulatory framework, it would be inappropriate for DNR to recommend a method of establishing spacing units that does not take this data into consideration.
Spacing Units	Who proposes spacing units	As for who should propose spacing units, the options amongst the various oil and gas states appear to either be the operator, the state, or both. Minnesota is at the start of a gas resource development industry. There are significant questions as to the size and shape of developable gas resources, or whether these resources are concentrated in fracture zones or porous rock formations. The state lacks the capacity to answer those questions on its own, which limits its ability to propose spacing units independent of an applicant. As a result, a process where an applicant proposes a spacing unit, and provides within their application the data needed for the state to independently assess their proposal, appears to be the best way to protect the correlative interests of Minnesota’s landowners.

Theme	Subtheme	Consideration
Spacing Units	Property line setbacks	Suggestions that DNR establish property line setbacks that would keep gas wells a certain distance from an adjacent landowner/mineral interests owner were offered both in conjunction with state-wide fixed spacing units, but also as an alternative to using spacing units and pool orders to protect correlative interests. Property line setbacks were an early attempt to counter the rule of capture…the idea being that if the well on your property is a certain distance away from your neighbor’s land, then it would be unlikely (or, at least, less likely) that your well would extract oil or gas resources under your neighbor’s property. DNR believes that property line setbacks are not needed when pooling and spacing rules are available to protect correlative interests. Also, property line setbacks cannot protect correlative interests when a gas well’s extraction area extends beyond the property boundaries of the parcel on which it is drilled. As an example, Pulsar Helium’s Jetstream #1 was drilled on a forty-acre parcel of private mineral interests bordered on three sides by 40-acre parcels of state-managed mineral rights. With a minimum reservoir size currently estimated to be 80 acres, no amount of setback within the 40-acre parcel could avoid negatively impacting the correlative interests of the State of Minnesota.
Spacing Units	General	DNR’s recommendations distinguish between the surface footprint of gas resource development locations and spacing units that reflect a subsurface extraction area. DNR considered suggestion that pump-test data only be required before production, and not required for dry or marginal wells. DNR will need to evaluate the well data used by a spacing unit applicant to support their proposed spacing unit; if a gas well is not going to be put into production within that spacing unit, there’s no need to review data from that well. The MDH revised recommendation for gas exploratory borings would also shield at least some of the exploratory boring data from review (Exploratory boring data used to help determine the size and shape of a gas resource could be relevant for establishing a spacing unit).
Tax Distribution	Different tax rates	Revenue considered the comments on the need for distinct and different tax rates. Because tax rates are a policy decision, Revenue did not insert any specific tax rates. However, Revenue intends to provide policymakers information on the financial implications of proposed tax rates once they are proposed.
Tax Distribution	General	Revenue recognizes that the distribution of tax proceeds is an important policy decision. As such, these decisions should be made through the legislative process. Revenue will provide policymakers with information regarding existing distribution models in MN and other states to aid in establishing a distribution model for gas and oil proceeds in Minnesota.
Tax Distribution	Tax proceeds to Tribes	Revenue recognizes that the distribution of tax proceeds is an important policy decision. As such, these decisions should be made through the legislative process. Revenue will provide policymakers with information

Theme	Subtheme	Consideration
		regarding existing distribution models in MN and other states to aid in establishing a distribution model for gas and oil proceeds in Minnesota.
Revenue Generation	Tax exemptions	Revenue considered the comments on the need for economic analysis and agrees that economic analysis is an important component of this work. Given the short turnaround time for this report, Revenue focused first on tax structure analysis and will continue to analyze the economic impact of numerous factors including tax rates and exemptions.
Revenue Generation	Tax rates	Revenue considered the comments on the need for specific tax rates. Because the tax rate is a policy decision, Revenue did not insert a specific tax rate. However, Revenue intends to provide policymakers information on the financial implications of proposed tax rates once they are proposed.
Revenue Generation	Need for economic analysis	Revenue considered the comments on the need for economic analysis and agrees that economic analysis is an important component of this work. Given the short turnaround time for this report, Revenue focused first on tax structure analysis and will continue to analyze the economic impact of numerous factors including tax rates and exemptions.
Gas Production Permitting	Permit fees duplicated to Tribes	DNR has considered the recommendation offered by some Tribes that when a gas resource development project is located on ceded territory that the permit applicant should pay the same application fee and annual permit fee paid to DNR to the tribes that ceded that territory. DNR has statutory authority to collect fees to cover the costs of legislatively mandated permitting and reclamation programs for metallic mine projects and is requesting that same for gas production permits. The DNR lacks authority to require a permit applicant to pay equivalent amounts to a Tribe.
Gas Production Permitting	Permit fees too high	The DNR agrees that its recommended application fee and annual permit fees, if adopted by law, would be higher than other states (the Best Regulatory Practices Report in Appendix A agrees as well). As noted in the recommendation's rationale, there is currently no gas production in the state, and no revenue to be generated for regulatory and permitting program support if alternatives such as severance taxes were employed. Application and supplemental application fees are actually advanced payments applied towards the actual costs for DNR to review permit applications and prepare permits. DNR acknowledges that gas development projects have much smaller footprints than open-pit mines, and anticipates that financial assurance requirements and reclamation costs will be lower for gas development projects will similarly track. Input that high permit fees should not be imposed upon explorers who lack control of a known resource or near-term prospects for production revenue was at least partially addressed by MDH's revised recommendation that explorers be allowed to drill gas exploratory borings without a development permit.

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		The suggestion that natural hydrogen projects should have lower permit fees than helium projects because their revenue potential is much lower is consistent with our observation that permit fees for other types of natural resource development at least partially reflect revenue potential (e.g., peat mines). DNR anticipates opportunities to revisit permit fees and alternative revenue streams once there is actual gas production in the state, and more is known about the scope, scale, and profitability of natural hydrogen projects.
Gas Production Permitting	Permit fee transparency	DNR recommends application fees and supplemental application fees that provide applicants complete transparency with respect to what those fees pay for and how they are spent. As noted in the draft legislative language, the DNR must provide an applicant the estimated costs for agency staff to review the permit application and process the permit, and there must be a signed agreement reflective of those costs before permit review begins.
Gas Production Permitting	Reclamation fees	DNR has considered the input provided on reclamation fees for gas development projects. The section of draft legislative language titled "RECLAMATION FEES" (93.5175) actually covers supplemental application fees and the annual permit fee (that are addressed in the consideration for the "Permit fees too high" subtheme). There was input that was related to reclamation costs estimates to satisfy financial assurance requirements. A "wait and see" approach that waits to the end of a project to determine reclamation costs runs the risk of an operator abandoning the project or declaring bankruptcy before the reclamation phase begins, leaving taxpayers to pay cleanup costs.
Gas Production Permitting	Temporary permits	Several submissions argued that "temporary permits" issued under a temporary regulatory framework should expire once rulemaking is completed and a permanent regulatory framework is established. DNR acknowledged this interpretation of the somewhat ambiguous statutory language as one option before the legislature, as well as the option offered in one comment that temporary permits should expire after a relatively short term. DNR appreciates the offered reasoning, but stands behind recommendation that permits issued during rulemaking have terms that do not expire when rules are promulgated. DNR's rationale, alongside the comments provided on this topic that are archived in this report's appendices, will provide a sound basis for the state legislature to consider the matter.
Gas Production Permitting	Need for all required permits	DNR agrees that a gas resource development project needs to obtain all required permits before proceeding with development operations, the same as metallic mining projects.
Health and Environmental Quality	Need for solid waste permit	Currently as understood, no solid waste permits would be required as this is not an industrial activity that treats, transfers, stores, processes, or disposes of solid waste. Solid wastes must be managed as required in Minn. R. 7035.2535, subp. 5 through Industrial Solid Waste Management Plans (ISWMPs). Further, environmental review provides an opportunity to broadly look at radioactive wastes for proposed gas projects

Theme	Subtheme	Consideration
		during the temporary framework and thereafter. Lastly, please see the consideration text in response to the "Radioactive materials" subtheme, in this document.
Gas Production Permitting	Permit length	DNR recommends that a permit issued by the commissioner be granted for the term determined necessary to complete the gas development project, including reclamation or restoration. That determination would be largely based on the applicant's operations plan and anticipated production. An open-ended term valid for as long as the project's wells produce in paying quantities is not an option in Minnesota. If a project is still in production as the end of the permit term draws near, the operator has the option of applying for a permit amendment to extend the permit term. That said, the DNR may extend the term with or without the permittee's consent if it is deemed necessary to ensure compliance with reclamation requirements.
Gas Production Permitting	General	DNR has considered this input. The permit amendment fee is 10% of the gas resourced development permit application fee (subdivision 1, clause (1), rather than clause (3). The term "public interests" is used in correlative statutory language for metallic mine permits. Action: Correct reference in draft legislative language.
Gas Production Permitting	When is a permit needed	DNR has reviewed the diverse input tagged with this subtheme. Guidance on what happens when an explorer inadvertently encounters gas is addressed by MDH revisions to their recommendations.
Gas Production Permitting	Storage, transfer and delivery	GTAC understands the opportunities for subsurface hydrogen storage and the challenges posed by hydrogen for storage, transfer and delivery. The later would be subject to environmental review, and reclamation/contingency planning under permitting and financial assurance. We would expect a project proposal to utilize industry best practices developed for "gray" hydrogen production, storage, and transport.
Gas Production Permitting	Induced hydrogen	Input considered and appreciated. GTAC members are following the active research on this topic in Minnesota. "Induced" hydrogen would also potentially be considered in conjunction with carbon sequestration should the legislature wish to consider the opportunity and seek primacy for Class VI well permitting.
Gas Production Permitting	Mine permitting not best model for gas permitting	Recommendation DNR-3 (*Use existing statutes and rules for permitting mine projects in Minnesota as a model for establishing comparable permitting requirements and policies for gas resource development projects*) was addressed in several submissions. Most noted that there are significant differences between gas development and metal mining, and suggested that it would be inappropriate for a temporary regulatory framework and permitting for gas development to be based on statutes, rules and policies for regulating mine projects. GTAC agrees that gas resources have different properties than metallic mineral resources, and was not suggesting that both could be regulated and permitted under a common set of statutes and rules. As stated in

Theme	Subtheme	Consideration
		rationale for recommendation DNR-3, "DNR believes that new statutes and rules for permitting gas resource development in Minnesota should closely follow comparable regulations for evaluating and permitting mining projects, with modifications as needed to reflect the differences between gas resource development and the mining of solid minerals." (emphasis added). As an example, DNR suggested in a different recommendation that, "*Financial assurance requirements for a gas resources development projects should as a guide, follow similar financial assurance processes for nonferrous metallic mining projects* (DNR-14). This does not mean that the amount of financial assurance required for a gas resource development project would be the same as what would be required for an open-pit metal mine (it would almost certainly require far less). But the methods used to determine how much financial assurance would be needed, and how that financial assurance requirement could be met using different financial instruments might be the same (or almost so). Action: DNR notes that the disclaimer language provided in the rationale section of DNR-3 was not included in the recommendation. For clarity and in response to received input, the recommendation will be revised to clearly indicate that in using metal mining regulations as a model that there will be modifications made that reflect the differences between gases and solids, and gas development and mining.
Sharing public data	Pre-production report should go to Tribes	A pre-production report submitted by a permittee prior to production would be a public document that would be posted on-line by the DNR and available for download on the same day that it is received, similar to how permit applications and related documents are made public for non-ferrous metallic mine projects.
Sharing public data	Company proprietary data	DNR reviewed and appreciates this input. Expedited rulemaking for gas project annual reports will address this topic and will work with each permittee to ensure there is clear understanding of annual report requirements before such a report needs to be completed. DNR will apply its experience managing submitted confidential data for other permits to gas resource development permits and pooling and spacing unit applications.
Correlative rights	General	There was general agreement amongst those who provided input on the topic that the state has a compelling interest in protecting the correlative rights or interests of Minnesota's landowners. This input came from within both the Tribal community and industry stakeholders. Considering the specific input received on this topic: DNR appreciates the recommendation that the state take a conservative approach regarding authorizations to access shared resources. A deliberate and careful approach towards the review of spacing unit and pooling order applications is central to the protection of correlative interests. One commenter suggested that the protection of correlative rights is important enough to address both surface ownership and the ownership of mineral interests as part of the permitting process. DNR sees a

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		distinction between a permitting process (that defines how a gas resource is developed) and the protection of correlative interests (which defines who benefits from permitted resource development). This distinction is reflected in how other states separate the review of production permit applications from the review of pooling order applications. That said, these processes will likely take place in parallel within the same timeframe, and it is reasonable to assume that a gas resource development permit would not be issued until a related spacing unit is established and any need for a pooling order resolved. Another comment stressed that pooling and spacing statutes needed to accommodate the exploration process and not unintentionally restrict the ability of operators to efficiently develop gas resources. DNR notes that MDH has revised its recommendations to now allow for exploratory borings. Exploratory borings would not require a permit or an established spacing unit prior to drilling, and this change would allow for the exploration process. As for the efficiency of establishing spacing units and issuing pooling orders where they are needed, DNR agrees that timely reviews and decision-making is a good thing, so long as the policies and procedures used to conduct those reviews and make those decisions respects both the correlative interests of mineral interest owners within a spacing unit and their due process rights, as guaranteed by the state's constitution.
Gas wells	Well setbacks	GTAC received a comment agreeing with the requirement that a person must meet gas well isolation distances and recommended specific distances from a residential building, water supply well, and school facility or childcare facility. MDH reviewed isolations distances in other state's gas well regulations and based current physical separation distance recommendations on that review.
Gas wells	Well construction	MDH reviewed and considered input on this topic: Gas well construction notification. GTAC currently recommends that a gas well project go through environmental review and permitting before a construction notification is submitted to MDH. Connections and relationships between multiple gas wells will be identified through the environmental review and permitting process. Construction standards. MDH acknowledges commenters' recommendations for more specific standards and will consider additional details during rule making for authorized drilling fluids, gas well construction requirements, gas well sealing requirements, and drilling waste disposal. Well and boring definitions and use. MDH has reviewed and considered input regarding well and boring definitions and corresponding uses. MDH modified initial recommendation prohibiting gas exploration with exploratory borings to allow for gas exploration with exploratory borings prior to the gas resource development permit process with DNR.

Theme	Subtheme	Consideration
		Well and boring oversight by DNR. GTAC has considered comments suggesting oversight of wells and borings for gas development projects. MDH maintains the recommendation requesting new authority for the development of gas well rules. MDH's existing authority oversees the construction and sealing of wells and borings in the State. Rig registration requirements. One commenter recommended clarity on gas well rig registration renewal. MDH considered this recommendation and made changes to clarify the time period a rig registration is valid.
Gas wells	Well inspection	MDH maintains the recommendation to ensure gas well construction and sealing compliance by requiring access to a site for inspection. This recommendation is consistent with existing authority.
Gas wells	Regulatory oversight	GTAC received input agreeing with MDH's oversight for well and boring construction and sealing activities. One commenter recommended consideration for use of exploratory boring for gas exploration. MDH modified initial recommendation prohibiting gas exploration with exploratory borings to allow for gas exploration with exploratory borings prior to the gas resource development permit process with DNR.
Gas wells	Notifications	GTAC received input concerned about emergency notification and sealing notification requirements. MDH requires emergency notification of significant adverse public health or environmental effects to the Minnesota Duty Officer. The Minnesota Duty Officer then facilitates a centralized distribution of notification to applicable entities. The fees for construction and sealing notifications will financially support the processing of the received notification and inspection of gas wells.
Gas wells	Contractor licensing	One commenter provided options for alternative licensing and registration recommendations. MDH recommendation for licensing and registration is consistent with existing authority to oversee persons constructing, repairing, and sealing other types of wells and borings. The Health Enforcement Consolidation Act (HECA), Minnesota Statutes, section 144.99, authorizes MDH to conduct enforcement on licensed and registered persons. Certified representative qualification requirements are provided in MDH's recommendations. The process for applying to become a certified representative will be addressed during rulemaking.
Gas wells	Exploratory borings	GTAC received recommendations to create a mechanism for exploration of gas before a gas resource development permit, and environmental review, and consider approaches for determination of bedrock formations. MDH considered these recommendations and modified the initial recommendation prohibiting gas exploration with exploratory borings to allow for gas exploration with exploratory borings prior to the gas resource

Theme	Subtheme	Consideration
		development permit process with DNR. An exploratory boring would be authorized under these recommendations to explore for a gas resource but not production. One commenter recommended modification to existing exploratory boring regulation to allow for geologic materials identification. The commenter mentioned a need for drilling to determine bedrock formations and sampling for Hydrogen resource projects. Environmental wells, as authorized in Minnesota Rules, chapter 4725, provides a path for drilling to obtain samples of geologic materials for testing or classification.