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TO: **Minnesota Department of Natural Resources and Minnesota Gas Resources Technical Advisory Committee**

FROM: **Iron Range Exploration, LLC**

RE: **Comments From Iron Range Exploration, LLC to Minnesota Gas Resources Technical Advisory Committee (GTAC) Working Recommendations and Statutory Language for Permitting Gas Resource Development Under a Temporary Framework**

DATE: **December 23, 2024**

Dear GTAC:

Below, please find the comments of Iron Range Exploration, LLC (Iron Range) concerning the Minnesota Gas Resources Technical Advisory Committee's (GTAC) *Working Recommendations and Statutory Language for Permitting Gas Resource Development Under a Temporary Framework*, issued on November 15, 2024. These comments are due on December 23, 2024, and are therefore timely filed. In other jurisdictions, statutes and regulations for gas production[1] have developed over many decades, and Iron Range looks forward to helping GTAC and the State of Minnesota establish balanced and meaningful statutes and regulations that will ensure the protection of Minnesota's abundant natural resources while facilitating economic development.

I. Introduction

Iron Range is a natural hydrogen exploration company dedicated to advancing the discovery and development of hydrogen reserves as a clean and sustainable energy resource. With a mission to identify and harness the potential of natural hydrogen, Iron Range utilizes cutting-edge technology and scientific expertise to support the transition to a low-carbon energy future.

II. Important Differences Between Gas Development and Mining

The development of gas projects differ significantly from mining operations for nonferrous metals and other minerals. Across the United States, gas development operations employ specialized practices that are distinct from those used in mining, even where there may be seeming similarities. Iron Range urges GTAC to recognize these differences to establish effective and practical regulatory frameworks for gas development.

Accordingly, Iron Range urges GTAC to adopt statutes and regulations specifically tailored to address the unique characteristics and operational needs of gas production. 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.

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. By implementing a regulatory structure that reflects the unique aspects of gas production, GTAC can promote responsible development while fostering legal clarity and economic growth in Minnesota.

i. **DNR-1:** In DNR-1, GTAC proposes focusing on gas resource development during the construction of a temporary framework and during the expedited rulemaking.

Iron Range Comment: It is critical to recognize that gas exploration and development is a unique industry that requires specifically tailored statutes and regulations. 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.

ii. **DNR-2:** In DNR-2, GTAC proposes giving MDH authority over the "sealing" of gas wells. GTAC also proposes striking "natural gas" from Minnesota's statutory definitions.

a. **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**.

b. **Iron Range Comment on Abandonment of Gas Wells**: 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. Accordingly, Iron Range recommends that the DNR be the primary agency overseeing the plugging and abandonment of gas wells and that the DNR enter into an inter-agency memorandum of understanding to ensure that all MDH requirements are met as part of the DNR's regulatory oversight role.

III. Refinement of Definitions

Generally, Iron Range recommends that GTAC adopt detailed definitions relevant to the gas industry, which is highly specialized and distinct from mining.

i. **MDG-2:** 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. For convenience, Iron Range provides the following definitions from various state jurisdictions with established gas regulations. Iron Range believes that reviewing these select definitions and the comprehensive schemes for gas regulation in other jurisdictions will provide GTAC valuable insights as it contemplates a gas regulatory framework that meets the needs of Minnesota.

Please see **Appendix I** for a proposed list of definitions applicable to gas.

IV. Fee Structure

DNR-7: In DNR-7, GTAC recommends an application fee of $50,000 for a gas resource development permit and "supplemental fees" to cover the costs of reviewing an application. The DNR also recommends a $75,000 annual permit fee.

Iron Range Comment: 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. 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. Below, Iron Range provides examples of fees in other jurisdictions.

- **i.** **New Mexico Permit Fees**: Range from $500 for Applications for Permits to Drill to $10,000 for gathering facilities.
- **ii.** **Texas Permit Fees**: Range from $500-$750 for Drilling Permits [2]
- **iii.** **Colorado Permit Fees**: Range from $100 for filings to $12,500 for various county siting permits prior to conducting drilling activities.

[2] Texas Railroad Commission Oil and Gas Fees and Surcharges, available at https://www.rrc.texas.gov/oil-and-gas/applications-and-permits/oil-gas-fees-surcharges/.

V. Permitting Requirements and Processes

i. DNR-3: 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 Comment: 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. Such regulations do not need to be developed from "scratch" because numerous and effective examples can be drawn from other jurisdictions and tailored to meet Minnesota's unique circumstances. 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.

a. **New Mexico Statutes Annotated** – Oil and Gas Act (Sections 70-2-1 through 70-2-38)[3]

  i. **New Mexico Administrative Code**: Title 19, Chapter 15 – Oil and Gas.[4]

b. **Texas Natural Resources Code:**[5]

  i. **Texas Administrative Code:** The Texas Railroad Commission has established detailed rules for operators seeking to develop gas wells and has a library of permit applications for the specific operations sought to be undertaken by oil and gas operators.[6]

c. **North Dakota Century Code – Chapter 38-08 Control of Gas and Oil Resources**[7]

  i. **North Dakota Administrative Code** – 43-02-03 through 43-05-01[8]

d. **Colorado ECMC Complete Rules – 100 series through 1300 series and associated appendices**

Energy and Carbon Management Commission (ECMC): Colorado has established detailed rules covering every aspect of the upstream gas industry

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[3] 3 *See* New Mexico Oil and Gas Act, available at https://nmonesource.com/nmos/nmsa/en/item/4440/index.do#!fragment/zoupio-_Toc97293393/BQCwhgziBcwMYgK4DsDWszIQewE4BUBTADwBdoAvbRABwEtsBaAfX2zgE4B2AJg4GZ+AgJQAaZNlKEIARUSFcAT2gByFaIiEwuBHIXK1GrTpABlPKQBCygEoBRADJ2AagEEAcgGE7o0mABG0KTswsJAA

[4] See New Mexico Administrative Code, Title 19, Chapter 15 – Oil and Gas, available at https://www.srca.nm.gov/nmac-home/nmac-titles/title-19-natural-resources-and-wildlife/.

[5] *See* Texas Natural Resources Code, Chapter 52, available at https://statutes.capitol.texas.gov/.

[6] *See* 16 TAC Section 3.80 - Commission Oil and Gas Forms, Applications, and Filing Requirements, available at https://www.rrc.texas.gov/media/klwdfexb/chapter3-all-text-effective-nov21-2022.pdf; See also Texas Railroad Commission – Forms, available at https://www.rrc.texas.gov/forms/.

[7] *See* North Dakota Century Code Chapter 38-08, available at https://ndlegis.gov/cencode/t38c08.pdf.

[8] *See* North Dakota Administrative Code Chapter 43-02-03, available at https://ndlegis.gov/information/acdata/pdf/43-02-03.pdf.

and has extensive guidance and forms required for specific operations sought to be undertaken by gas operators.[9]

ii. **DNR-4:** In DNR-4, GTAC proposes requiring permits for gas resource development projects prior to drilling gas well.

Iron Range Comment: 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.

a. **New Mexico Permit Process**: The New Mexico Administrative code sets forth specific requirements for persons or entities engaged in gas development and production.[10] New Mexico has also developed forms requiring specific information based on the action(s) contemplated for specific gas development operations.

b. **Texas Permit Process**: Texas has developed regulations governing applications for permits to drill, deepen, reenter, or plus wells for gas operators.[11]

c. **North Dakota Permit Process**: The North Dakota Century Code sets forth specific requirements for persons or entities engaged in gas development and production within North Dakota. North Dakota has also developed forms requiring specific information based on the action(s) contemplated for specific gas development operations.[12]

d. **Colorado Permit Process**: The ECMC code sets forth specific requirements for persons or entities engaged in gas development and production within Colorado. Colorado has also developed forms requiring specific information based on the action(s) contemplated for specific gas development operations. Additionally, certain local governments require concurrent permitting for gas in areas such as siting, building and electrical codes, and other requirements. Colorado requires a permit for both the surface location and the well(s).[13]

iii. **DNR-5:** 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. 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

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[9] *See* ECMC Complete Rules, available at https://ecmc.state.co.us/reg.html#/rules.
[10] *See* 19.15.7.1 NMAC – Forms and Reports, available at https://www.srca.nm.gov/parts/title19/19.015.0007.pdf; See also New Mexico Oil Conservation Division Forms, available at https://www.emnrd.nm.gov/ocd/ocd-forms/.
[11] *See* 16 TAC § 3.5 – Application To Drill, Deepen, Reenter, or Plug Back, available at https://www.rrc.texas.gov/media/klwdfexb/chapter3-all-text-effective-nov21-2022.pdf ffective-nov21-2022.pdf; *See also* Texas Railroad Commission – Forms, available at https://www.rrc.texas.gov/oil-and-gas/oil-and-gas-forms/.
[12] *See* NDCC 38-08-05 – Drilling Permit Required, available at https://ndlegis.gov/cencode/t38c08.pdf.
[13] *See* ECMC 300 Series Rules, available at https://ecmc.state.co.us/documents/reg/Rules/LATEST/300%20Series%20-%20Permitting%20Process.pdf.

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.

iv. **DNR-6:** 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. As part of the drilling process, the pipe utilized must be properly cemented and cased through phases of the drilling process to ensure groundwater is protected. Mechanical integrity tests are required to ensure that the wellbore prevents gas from impacting water and other geologically sensitive formations and strata.

a. <u>Temporary Permitting for Exploration</u>: 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.

b. <u>Clarify or Change the definition of "Gas Extraction"</u>: 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."

v. **DNR-8:** 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. The initial permit should also enable the operator to apply for extensions to permitted development plans without incurring additional fees.

vi. **DNR-13:** 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. 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. 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.

a. **Texas Contested Case Hearings**: Texas has established detailed rules and procedures for gas operators to propose and obtain approval for gas operations.[14] These rules provide a clear hearing process for the public and gas operators to furnish to the Texas Railroad Commission evidence for their development plans and operations and allow the RRC to impose requirements for prudent gas development.

b. **New Mexico Contested Case Hearing**: New Mexico has established a cohesive adjudication process that gas operators must follow under the New Mexico Administrative Code.[15] This process enables gas operators to propose various gas production operations and provides the other gas operators public the opportunity to propose alternatives. Importantly, this process also enables the New Mexico Oil Conservation Division to modify proposals to ensure that correlative rights and other natural resources are protected.

vii. **MDH-1:** 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." Further, even 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.

[14] *See* 16 TAC § 1.1 – Practice and Procedure, available at https://www.rrc.texas.gov/media/vbqniigi/chapter1-all-effective-aug21-2017.pdf.

[15] *See* 19.15.4.1 NMAC – Adjudication, available at https://www.srca.nm.gov/wp-content/uploads/attachments/19.015.0004.pdf.

viii. **MDH-3:** 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. Iron Range proposes establishing clear criteria for the "plugging and abandonment of a well" that meets established requirements.

i. **New Mexico Plugging and Abandonment Regulations**: 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."[16]

ii. **Texas Plugging Regulations**: 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."[17]

ix. **MDH-4:** 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.

a. **New Mexico**: New Mexico specifically authorized its Energy, Minerals, and Natural Resources Department (EMNRD) to enter into inter-agency agreements ensuring that EMNRD's Oil Conservation Division requires gas operators to meet specific requirement when conducting gas operations as approved by the New Mexico Environment Department (NMED), e.g., air quality requirements and water quality

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[16] *See* 19.15.25.1 NMAC – Plugging and Abandonment of Wells, available at https://www.srca.nm.gov/wp-content/uploads/attachments/19.015.0025.pdf.
[17] *See* 16 TAC § 3.14 – Plugging, available at https://texreg.sos.state.tx.us/public/readtac$ext.TacPage?sl=R&app=9&p_dir=&p_rloc=&p_tloc=&p_ploc=&pg=1&p_tac=&ti=16&pt=1&ch=3&rl=14.

standards, or the New Mexico Office of the State Engineer (OSE), e.g., groundwater aquifer protection.

b. **Texas**: Coordination between the Texas Railroad Commission and The Texas Commission on Environmental Quality is established by regulation and memorialized through a memorandum of understanding between the two agencies.[18]

x. **MDH-5:** 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). However, as stated in its comment to MDH-4, establishing a single authority with the requisite training and expertise to ensure that gas development in Minnesota meets the established statutory and regulatory requirements, facilitates greater efficiency. Accordingly, 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.

a. **Texas**: Texas gas rules authorize the Railroad Commission to access any lease or property operated or controlled by an gas operator.[19]

b. **New Mexico**: New Mexico's gas regulations are clear that New Mexico State land Office personnel or Oil Conservation Division personnel may, from time to time, review and inspect oil-field operations and recommend actions necessary to comply with reasonable use of the surface and prudent operator standards.[20]

c. **Colorado**: ECMC regulations grant the agency director and staff the right at all reasonable times to go upon and inspect any gas location, disposal facility, or similar, for the purpose of ascertaining compliance or special field rules.[21]

d. **North Dakota**: North Dakota's gas regulations allow the commission, director, and representatives to have access to all sites and records, wherever located for inspection.[22]

xi. **MDH-6:** 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

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[18] *See* 16 TAC § 3.8(1)(D)(3)(i) – Water Protection, available at https://www.rrc.texas.gov/media/klwdfexb/chapter3-all-text-effective-nov21-2022.pdf; *See also* 16 TAC § 3.30 - Memorandum of Understanding between the Railroad Commission of Texas (RRC) and the Texas Commission on Environmental Quality (TCEQ).
[19] *See* 16 TAC § 3.12 – Commission Access to Properties.
[20] *See* 19.2.100.66(D)(1)-(2) NMAC –Review and Inspection.
[21] *See* ECMC Rules – 200 Series, available at https://ecmc.state.co.us/documents/reg/Rules/LATEST/200%20Series%20-%20General%20Provisions.pdf.
[22] *See* N.D.A.C. 43-02-03-14, available at https://ndlegis.gov/information/acdata/pdf/43-02-03.pdf.

industry practices for addressing particular and known events requiring immediate action by gas operators, e.g., dealing with blowouts, leaks, spills, etc. Other jurisdictions have established such mechanism and Iron Range provides the following examples:

i. **New Mexico Release Regulations:** New Mexico's regulations concerning releases of gas classify releases based on size, e.g., "major" and "minor" and establish processes and procedures for notifying state authorities, reporting the nature of a release, containing the release, releases and remediating any impacts from releases, and closing the release site per state approval once a release has been addressed.[23]

ii. **Texas Release Regulations**: Texas requires operators to provide the Texas Railroad Commission with immediate notice of any fires, leaks, or spills by telephone followed with a letter giving the full description of the event and the volume of gas product lost.[24]

iii. **Colorado Regulations**: Colorado's regulations concerning environmental releases and incidents via form 19. Any spill or release which may impact waters of the State must be reported as soon as practicable; any spill over 20 bbls must be reported within 24 hours and all spills over five bbls must be reported within ten days.[25]

iv. **North Dakota Regulations**: North Dakota's regulations use a whole-of-government approach for developing long-term strategies for managing energy development in an environmentally responsible manner. The state's Unified Spill/Tier II reporting system is a tool for and effective state response and a mitigation strategy for unanticipated spill events.[26] Notification requirements prescribed by North Dakota do not apply to any leak or spill involving only freshwater or to any leak, spill, or release of crude oil, produced water, or natural gas liquid that is less than one barrel total volume and remains onsite of a site.

xii. **MDH-7:** 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.

a. **Texas Injection Regulations**: Texas requires gas operators to file an application that may be protested during its hearing process with the Texas Railroad Commission for approval to inject fluids into productive reservoirs.[27]

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[23] *See* 19.15.29.1 NMAC – Releases, available at https://www.srca.nm.gov/parts/title19/19.015.0029.pdf.
[24] *See* 19.15.29.1 NMAC – Notification of Fire, Breaks, Leaks, or Blow-outs, available at https://www.rrc.texas.gov/media/klwdfexb/chapter3-all-text-effective-nov21-2022.pdf.
[25] *See* ECMC Rule 912b Reporting Spills or Releases of E&P Wastes, Gas, or Produced Fluids, available at https://drive.google.com/file/d/1-dP8bpCsvAfhNipobgFpU79WbMgxJxDu/view.
[26] *See* N.D.A.C. 43-02-03-30; *see also https://www.dmr.nd.gov/dmr/oilgas/spills.*
[27] *See* 16 TAC § 3.46 – Fluid Injection into Productive Reservoirs, available at https://www.rrc.texas.gov/media/klwdfexb/chapter3-all-text-effective-nov21-2022.pdf.

b. **Texas Waste Management Regulations**: Texas has established standards for waste management for activities associated with gas production, which are consistent with the requirements of the United States Environmental Protection Agency.[28]

c. **New Mexico Injection Regulations**: New Mexico has established a robust regulatory scheme to ensure that gas operators conduct all injection activities in compliance with the federal Safe Drinking Water Act and obtain a permit to conduct such activities.[29]

d. **Colorado Waste Management Regulations**: Colorado allows gas waste to be injected into Class II underground injection wells with a permit and prior approval by the Director, who ensures that all injection activities are in compliance with the federal Safe Drinking Water Act.[30]

e. **North Dakota Waste Management Regulations**: North Dakota has established standards for waste management for activities associated with gas production.[31]

xiii. **MDH-8:** 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.

xiv. **MDH-9:** 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.

a. **New Mexico Waste Disposal Regulations**: New Mexico regulates liquid oil field waste and other wastes under particular sections of the New Mexico Administrative Code. Liquid waste is typically in the form of produced water on the surface or subsurface, and encourages the reuse or recycling of such liquid waste.[32] New Mexico

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[28] *See* 16 TAC § 3.98 – Standards for Management of Hazardous Oil and Gas Waste, available at https://www.rrc.texas.gov/media/klwdfexb/chapter3-all-text-effective-nov21-2022.pdf.
[29] *See* 19.15.26.1 NMAC – Injection, available at https://www.srca.nm.gov/wp-content/uploads/attachments/19.015.0026.pdf.
[30] *See* ECMC 800 Series Rules – Underground Injection for Disposal and Enhanced Recovery Projects - Rule 801, available at https://ecmc.state.co.us/documents/reg/Rules/LATEST/800%20Series%20-%20Underground%20Injection%20for%20Disposal%20and%20Enhanced%20Recovery%20Projects.pdf.
[31] *See* N.D.A.C. 43-02-03-19.2D; https://ndlegis.gov/information/acdata/pdf/43-02-03.pdf.
[32] *See* 19.15.34.1 NMAC – Produced Water, Drilling Fluids and Liquid Oil Field Waste, available at https://www.srca.nm.gov/parts/title19/19.015.0034.pdf.

also requires certain oi field waste to be disposed at approved solid waste facilities in accordance with United States Environmental Protection Agency requirements.[33]

b. **Texas Waste Disposal Regulations**: Texas has robust regulations for solid and liquid waste disposal that it enforces in accordance with Texas Commission on Environmental Quality requirements.[34] Texas's waste disposal regulations are designed specifically to ensure water resource protections.[35]

c. **North Dakota Waste Regulations**: North Dakota waste regulations require all waste material associated with exploration or production of gas be properly disposed of in an authorized facility in accordance with all applicable local, state, and federal laws and regulations.[36]

d. **Colorado Waste Regulations**: Colorado's waste regulations obligate operators to ensure that gas waste is properly stored, handled, transported, treated, recycled, or disposed to prevent threatened or actual adverse environmental impacts to air, water, soil, or biological resources, or to the extent necessary to ensure compliance. Operators are required to prepare a comprehensive waste management plan detailing how the Operator will treat, characterize, manage, store, dispose, and transport all types of waste generated.

xv. **MDH-10:** 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.

1. A list of some of the common additives consistently required when drilling gas wells are:
    1. Viscosifiers – create carrying capacity (lifting the cuttings out of the way of the bit and out of the wellbore). They come in many forms (clay, starch, liquid, etc.) and selection is based on offset information and the anticipated formations that will be drilled through.
    2. Weighing agents – helps with wellbore stability and managing downhole pressures. Barite is very commonly used and is inert and doesn't chemically react with other mud additives.

[33] *See* 19.15.35.1 NMAC – Waste Disposal, available at https://www.srca.nm.gov/wp-content/uploads/attachments/19.015.0035.pdf.
[34] *See* Gas Facilities: Waste Compliance Information, Texas Commission on Environmental Quality, available at https://www.tceq.texas.gov/assistance/industry/oil-and-gas/oilgas_waste.html.
[35] *See* 16 TAC § 3.8 – Water Protection, available at https://texreg.sos.state.tx.us/public/readtac%24ext.TacPage?sl=R&app=9&p_dir=&p_rloc=&p_tloc=&p_ploc=&pg=1&p_tac=&ti=16&pt=1&ch=3&rl=8.
[36] *See* N.D.A.C. 43-02-03-19.2 Disposal of waste materials, available at https://ndlegis.gov/information/acdata/pdf/43-02-03.pdf.

3. Surfactants (soaps) – these help prevent formations from sticking to the bit, they add lubricity the wellbore and reduce torque and drag while drilling. Surfactants are also used to inhibit problematic swelling shales.
4. Thickeners – create viscosity, aid in wellbore stability and carrying capacity of cuttings.

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.

VI. Financial Assurance Requirements

DNR-14: 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.

a. **Texas Financial Assurance Requirements**: Texas allows gas operators to provide financial securities, such as individual performance bonds, blanket performance bonds, letters of credit, or cash deposits filed with the Texas Railroad Commission.[37] The amounts associated with each bond depends on the number of wells a particular operator owns and operates and ranges from $25,00 (10 wells and less) to $250,000 (100 wells or more).

b. **New Mexico Financial Assurance Requirements**: New Mexico has established financial assurance requirements and corresponding forms that must be filed and

[37] *See* 16 TAC § 3.78 – Fees and Financial Security Requirements, available at https://www.rrc.texas.gov/media/klwdfexb/chapter3-all-text-effective-nov21-2022.pdf.

approved by the New Mexico Oil Conservation Division.[38] The financial assurance can be in the form of an irrevocable letter of credit, plugging insurance policy or cash or surety bond running to the state of New Mexico. The amount of financial assurance is scaled based on the number of wells an gas operator operates, e.g., $50,000 (1-10 wells) and $250,000 (more than 100 wells). Inactive wells require higher financial assurance amounts, e.g., $150,000 (1-5 wells) and $1,000,000 (more than 25 wells).

c. **Colorado Financial Assurance Requirements**: Colorado has established financial assurance requirements and corresponding forms that must be filed and approved by the Energy and Carbon Management Commission. The preferred forms of financial assurance can be in the form of cash bond, surety bond, or another alterative as requested by the operator and approved by the Commission. The amount of financial assurance is scaled based on the number of wells an gas operator operates, e.g., $12,000 per well (1-50 wells) and $10,000 (50 to 150 wells), $5,000 per well (150-1,500 wells), $3,000 per well (1,500-4,000 wells) and $1,500 per well (more than 4,000 wells). Operators file a financial assurance plan annually with the ECMC.[39]

d. **North Dakota Financial Assurance Requirements**: North Dakota requires any person who proposes to drill a well for oil, gas, injection, or source well for use in enhanced recovery operations, to submit to the director and obtain the approval of the director, a surety bond or cash bond prior to commencing construction of a site or appurtenance or road access. An alternative form of security may be approved by the commission after notice and hearing. The operator shall be the principal on the bond covering the well. Each surety bond shall be executed by a responsible surety company authorized to transact business in North Dakota.[40]

VII. Setback Requirements

DNR-9: 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. 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.

a. **Texas and New Mexico Setback Requirements**: Presently, neither Texas or New Mexico have setbacks for gas development.[41] In New Mexico, for gas wells, setbacks

[38] *See* 19.15.8.1 NMAC – Financial Assurance, available at https://www.srca.nm.gov/wp-content/uploads/attachments/19.015.0008.pdf.
[39] ECMC Financial Assurance Rules – 700 series, available at https://ecmc.state.co.us/documents/reg/Rules/LATEST/700%20Series%20-%20Financial%20Assurance.pdf.
[40] *See* N.D.A.C. 43-02-03-15 Bond and Transfer of Wells, available at https://ndlegis.gov/information/acdata/pdf/43-02-03.pdf.
[41] *See* New Mexico Legislative Finance Report on Setbacks, June 11, 2024, available at https://www.nmlegis.gov/Handouts/ALFC%20061124%20Item%203%20Hearing%20Brief%20-%20Oil%20and%20Gas%20Setbacks.pdf.

are typically required to be 300' feet from lease lines, unless otherwise established by Oil Conservation Division orders. Setbacks are also established by city and county authorities, which typically prescribe certain distances from potentially sensitive establishments such as schools, hospitals, and municipal water systems. Texas's setback requirements are established by Statewide spacing Rule 37.[42]

b. **Colorado Setback Requirements**: The ECMC has extensive setback requirements. Generally, wells cannot be located less than 200 feet from buildings, public roads, railroads, etc. Additionally, no working pad surface may be located within 2,000 feet or less from a school or childcare facility or less than 500 feet from 1 or more residential building units. ECMC regulations apply highly advanced screening (wildlife, population, environmental justice) tools to place conditions on locations and setbacks.[43]

c. **North Dakota Requirements**: North Dakota requires notice to the owner of any permanently occupied dwelling located within one thousand three hundred twenty feet of the proposed oil or gas well. Unless waived by the owner or if the commission determines that the well location is reasonably necessary to prevent waste or to protect correlative rights, a drilling permit for an oil or gas well will not be issued if located within five hundred feet of an occupied dwelling.[44]

VIII. Reporting Requirements

DNR-10: 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.

a. **Texas Reporting Requirements**: Texas requires monthly gas production reports to be filed with the Texas Railroad Commission by the twenty-fifth day of each calendar month for the immediately preceding month.[45] Texas also requires annual well tests and well status reports.[46]

b. **New Mexico Reporting Requirements**: New Mexico has many reporting requirements for gas operations. For example, New Mexico requires gas-oil ratio tests,

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[42] *See* 16 TAC § 3.37 – Statewide Spacing Rule, available at https://texreg.sos.state.tx.us/public/readtac$ext.TacPage?sl=T&app=9&p_dir=N&p_rloc=117866&p_tloc=9930&p_ploc=1&pg=2&p_tac=&ti=16&pt=1&ch=3&rl=36.
[43] *See* ECMC 600 Series Rules – 604 Setbacks and Siting, available at https://ecmc.state.co.us/documents/reg/Rules/LATEST/600%20Series%20-%20Safety%20and%20Facility%20Operations%20Regulations.pdf.
[44] *See* N.D.C.C. 38-08-05 Setbacks, available at https://ndlegis.gov/cencode/t38c08.pdf.
[45] *See* 16 TAC § 3.54 – Gas Reports Required, available at https://www.rrc.texas.gov/media/klwdfexb/chapter3-all-text-effective-nov21-2022.pdf.
[46] *See* 16 TAC § 3.53 – Annual Wells Tests and Well Status Reports, available at https://www.rrc.texas.gov/media/klwdfexb/chapter3-all-text-effective-nov21-2022.pdf.

annual productivity tests, bottom hole pressure rests, monthly produced water reports, and gas transfer reports, each of which must be reported on forms established by the New Mexico Oil Conservation Division.[47]

DNR-11: 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.

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. 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.

IX. Pooling and Spacing Recommendations

DNR-18: 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,

[47] *See* 19.15.18.1 NMAC – Production Operating Practices, available at https://www.srca.nm.gov/parts/title19/19.015.0018.pdf; See also New Mexico Oil Conservation Division Forms, available at https://www.emnrd.nm.gov/ocd/ocd-forms/.

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.

DNR-19, DNR-20, and DNR-23: 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. 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. 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. 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. Finally, Iron Range encourages GTAC to establish formal timing requirements and process procedures so that operators can schedule their development plans.

a. **New Mexico Pooling and Spacing Regulations**: New Mexico has sophisticated pooling and spacing requirements classify wells and establish well location and well acreage requirements and procedures for multiple operators within a spacing unit, obtaining approval of unorthodox well locations and for pooling or communitizing small acreage oil lots.[48] Different geologic formations in different parts of the state have differing spacing requirements based on their unique features and based on tests that are required to be applied to each well. Operators can also apply to the New Mexico Oil Conservation Division for non-standard spacing units, which has the authority to grant exceptions to established rules.

b. **Texas Spacing Regulations**: Gas well spacing regulations are established by Statewide Rule 37.[49]

c. **Colorado Spacing Regulations**: Colorado requires an operator to apply for a drilling and spacing unit for Commission review. In determining whether to recommend that the Commission approve or deny a proposed Drilling and Spacing Unit, the Director

[48] *See* 19.15.15.1 NMAC – Well Spacing and Location, available at https://www.srca.nm.gov/wp-content/uploads/attachments/19.015.0015.pdf.
[49] *See* 16 TAC § 3.37 – Statewide Spacing Rule, available at https://texreg.sos.state.tx.us/public/readtac$ext.TacPage?sl=T&app=9&p_dir=N&p_rloc=117866&p_tloc=9930&p_ploc=1&pg=2&p_tac=&ti=16&pt=1&ch=3&rl=36.

will consider whether the proposed Drilling and Spacing Unit protects and minimizes adverse impacts to public health, safety, welfare, the environment, and wildlife resources; Prevents waste of gas resources; Avoids the drilling of unnecessary Wells; and Protects correlative rights.[50]

d. **North Dakota Spacing Regulations**: Spacing units are set by the North Dakota Industrial Commission. The commission usually sets spacing units when necessary to prevent waste, to avoid the drilling of unnecessary wells, or to protect correlative rights. The may also commission establishes spacing units for a pool and may modify spacing units as necessary.[51]

DNR-21: 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. 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.

a. **New Mexico Compulsory Pooling**: New Mexico allows for the Oil Conservation Division or Oil Conservation Commission to pool interest in gas spacing units.[52] This authority allows for working interest owners or unleased mineral interest to be pooled by administrative order, and not by voluntary agreement. Generally, this allows operators to conduct gas operations and recover the costs associated with those operations before the working interest or unleased mineral interests are entitled to payment for their proportionate share of the proceeds from production. Working interest or unleased mineral interests are allowed to elect to participate in the operation and can also propose their own gas development plan.

b. **Texas Pooling Regulations**: Texas does not have compulsory pooling regulations and instead encourages small property owners to voluntarily pool their interest to effectuate efficient oil and production, prevent waste, and protect correlative rights.[53] Private interests in Texas can be force pooled only if the specific statutory requirements are followed and met.

c. **Colorado Involuntary Pooling Regulations**: The ECMC requires applications for involuntary (forced) pooling orders to be established only after notice to mineral owners of the tracts to be pooled. An application for involuntary pooling may be filed at any time by an Owner who owns, or has secured the consent of the Owners of, more than 45% of the mineral interests to be pooled within a Drilling and Spacing Unit

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[50] *See* ECMC – 300 Series Rules – Drilling and Spacing Unit, available at https://ecmc.state.co.us/documents/reg/Rules/LATEST/300%20Series%20-%20Permitting%20Process.pdf.
[51] *See* N.D.C.C. 38-08-07 – Commission Shall Set Spacing Units, available at https://ndlegis.gov/cencode/t38c08.pdf.
[52] *See* 19.15.13.1 NMAC – Compulsory Pooling, available at https://www.srca.nm.gov/wp-content/uploads/attachments/19.015.0013.pdf.
[53] *See* Tex. Nat. Res. Code § 102, Mineral Interest Pooling Act.

established by Commission order, prior to or after drilling of a Well, but no later than 90 days in advance of the date the matter is to be heard by the Commission. An application for involuntary pooling may be filed concurrently with the sending of a good faith, reasonable offer to lease or participate.[54]

d. **North Dakota Pooling Regulations**: North Dakota pooling regulations allow pooling when two or more separately 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 the owners and royalty owners thereof may pool their interests for the development and operation of the spacing unit. In the absence of voluntary pooling, the commission upon the application of any interested person shall enter an order pooling all interests in the spacing unit for the development and operations thereof.[55]

DNR-22: 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.

Iron Range Comment: Generally, Iron Range supports this proposal. However, the associated fees 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.

DNR-24: In DNR-24, GTAC proposes that a gas well should not be drilled before a pooling order issued.

Iron Range Comment: 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.

DNR-25: 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. Other jurisdictions have robust statutory and regulatory regimes to address myriad issues that arise during gas production. 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.

a. **Colorado Non-Consenting Mineral Owner Regulations**: Colorado allows a non-consenting mineral owner of a tract in a drilling unit that is not subject to any lease or other contract for gas development to have a landowner's proportionate royalty of

[54] *See* ECMC – 500 Series Rules – 506 Involuntary Pooling Applications, available at https://ecmc.state.co.us/documents/reg/Rules/LATEST/500%20Series%20-%20Rules%20of%20Practice%20and%20Procedure%20(EF%204-30-22).pdf; *see also* C.R.S. § 34-64-116.
[55] *See* N.D.C.C. 38-08-08 – Integration of Fractional Tracts, available at https://ndlegis.gov/cencode/t38c08.pdf.

thirteen percent for gas wells and sixteen percent for oil wells until the consenting owners recover, only out of the nonconsenting owner's proportionate eighty-seven-percent share of production or eight-four-percent share of production and eligible costs.[56]

b. **North Dakota Non-Consenting Mineral Owner Regulations**: North Dakota entitles unleased mineral owners to a cost-free royalty interest equal to the acreage weighted average royalty interest of the leased tracts within the spacing unit or, at the operator's election, a cost-free royalty interest of sixteen percent. The remainder of the unleased interest are treated as a lessee or cost-bearing interest.[57]

DNR-26: 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.

DNR-27: 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.

DNR-28: 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

[56] *See* C.R.S. § 34-60-116 – Drilling Units – Pooling Interests, available at https://law.justia.com/codes/colorado/title-34/oil-and-natural-gas/conservation-and-regulation/article-60/section-34-60-116/.

[57] N.D.C.C. 38-08-08 – Integration of Fractional Tracts, available at https://ndlegis.gov/cencode/t38c08.pdf.

implicate or affect federal or tribals lands, must submit all materials submitted to the regulatory to the affected federal or tribal entity.

X. Forfeited Severed Mineral Interests

DNR-29: 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.

XI. Taxation – Minnesota Department of Revenue

DOR-1: 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.

a. **Texas Gas Tax Regulations**: Under the Texas Tax Code, gas operators can obtain a reduction in severance tax for natural gas produced that is considered "high-cost natural gas."[58] Texas also allows gas operators to obtain a fifty-percent (50%) severance tax reduction for up to five years on the incremental oil and casinghead gas production from qualifying leases.[59]

XII. Environmental Reviews and Impacts

DNR-12: 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. 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

[58] *See* 16 TAC § 3.101 – Certification for Severance Tax Exemption or Reduction for Gas Produced From High-Cost Gas Wells, available at https://www.rrc.texas.gov/media/klwdfexb/chapter3-all-text-effective-nov21-2022.pdf.
[59] *See* 16 TAC § 3.102 – Tax Reduction for Incremental Production, available at https://www.rrc.texas.gov/media/klwdfexb/chapter3-all-text-effective-nov21-2022.pdf.

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.

EQB-1: In EQB-1, GTAC proposes requiring a mandatory EAW for any gas resource development project with the DNR serving as the Responsible Government Unit (RGU).

Iron Range Comments: Iron Range supports gas operators completing an EAW. However, Iron Range would appreciate the opportunity to review the proposed EAW prior to its finalization to help GTAC ensure that necessary and applicable information is listed for inclusion in EAWs completed and submitted to DNR by operators. Iron Range also appreciates the efficiency expressed through this proposal by requiring EAWs from the EQB to be reviewed by DNR and encourages similar delegation of EQB-approved requirements to DNR to serve as the RGU.

XIII. Conclusion

Iron Range Resources appreciates the opportunity to provide comments on GTAC's working recommendations and statutory language. 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.

Iron Range stands ready to collaborate with GTAC and other stakeholders to support the development of meaningful statutes and regulations that will lay a solid foundation for gas resource development in Minnesota.

Thank you for your consideration.

Statistical Language

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

ACCOUNT TO INVEST FINANCIAL ASSURANCE MONEY FROM PERMITS TO MINE AND GAS RESOURCE DEVELOPMENT PERMITS. (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)

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 or gas resource development permit 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 93.518 and rules adopted thereunder and as authorized under any trust fund agreements or other conditions established under a permit to mine or gas resource development permit.

(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 93.518 and rules adopted thereunder and as authorized under any trust fund agreements or other conditions established under the permit to mine or gas resource development permit 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. 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 3. 93.5122 DEFINITIONS (As set forth in its comments, Iron Range recommends the development of a robust set of definitions that adequately captures the unique and specific operations inherent in gas development)

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

Subd. 2. **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. To assist in this effort, Iron Range has provided examples of these established practices in its comments.)** 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 4. Section 93.513 is amended to read: (Please see Iron Range's comments in Section V, above)

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 5. 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 for the production of gas and oil; and

Section 6. 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 7. 93.5152 DEFINITIONS. (Please see Iron Range's example definitions for gas operations in Appendix I of its comments)

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 hearing and no more than 180 days prior to a hearing. The notice shall contain information as the commissioner of natural resources may direct.

Section 8. 93.5152 SPACING UNIT (Iron Range recommends reviewing its comments in Section IX, above)

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) Protects and minimizes adverse impacts to public health, safety, welfare, the environment, and wildlife resources;

(ii) Prevents waste of gas resources;

(iii) Avoids the drilling of unnecessary wells; and

(iv) 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. **(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).**

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. Any spacing regulation made by the commissioner shall apply to each individual pool separately and not to all units on a statewide basis.

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

Section 9. 93.5153 POOLING (Please see Iron Range's comments on pooling in Section IX, above)

Subd. 1. Voluntary pooling. When two or more separately owned tracts, including 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 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 **(Iron Range recommends public hearings/meetings be held in a set location with virtual attendance options available)** where the pooling area is located and must be upon terms and conditions that are just and reasonable 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 **reasonable** share. The pooling order must protect each owner's correlative rights.

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 an 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 has obtained 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. 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.

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. **(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)**

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) Operations incident to the drilling of a well upon any portion of a unit covered by a pooling order shall be deemed for all purposes to be the conduct of operations upon each separately owned tract in the unit by the several owners of each separately owned tract. That portion of the production allocated or applicable to each tract included in a unit covered by a pooling order shall, when produced, be deemed for all purposes to have been produced from the tract by a well drilled on it.~~**(a) Operations conducted in connection with the drilling of a well on any portion of a unit subject to a pooling order shall, for all purposes, be considered as operations conducted on each separately owned tract within the unit by the respective owners of those tracts. The portion of production allocated to each tract within the unit, as specified in the pooling order, shall be regarded as having been produced directly from that tract by a well drilled on it.**

(b) Each pooling order must:

(i) make provision for the drilling of one or more wells on the drilling unit, if not already drilled, for the operation of the wells, and for the payment of the reasonable actual cost of the wells, including a reasonable charge for supervision and storage. Except as provided in subdivision 9 of this section, as to each nonconsenting owner who refuses to agree to bear a proportionate share of the costs and risks of drilling and operating the wells, the order must provide for reimbursement to the consenting owners who pay the costs of the nonconsenting owner's proportionate share of the costs and risks out of, and only out of, production from the unit representing the owner's interest, excluding royalty or other interest not obligated to pay any part of the cost thereof, 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 8(c) of this section. In the event of any dispute as to the costs, the commissioner shall determine the proper costs as specified in subdivision 8(c) of this section;

(ii) determine the interest of each owner in the unit and provide that each consenting owner is entitled to receive, subject to royalty or similar obligations, the share of the production from the wells applicable to the owner's interest in the wells and, unless the owner has agreed otherwise, a proportionate part of the nonconsenting owner's share of the production until costs are recovered and that each nonconsenting owner is entitled to own and to receive the share of the production applicable to the owner's interest in the unit after the consenting owners have recovered the nonconsenting owner's share of the costs out of production;

(iii) specify that a 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; and

(iv) prohibit the operator from using the surface owned by a nonconsenting owner without permission from the nonconsenting owner. **(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.)**

(c) Upon the determination of the commissioner, proper costs recovered by the consenting owners of a spacing unit from the nonconsenting owner's share of production from such a unit shall be as follows:

(i) **(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)** , 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. It is the intent that the 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 **(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.)**.

(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. A nonconsenting owner of a tract in a drilling unit that is not subject to any lease or other contract for gas development shall be deemed to have a landowner's proportionate royalty of twelve and **one-half** percent **(gas 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%)** until the consenting owners recover the costs specified in subdivision (8)(c) of this section. For purposes of calculating cost recovery, **the 18.75% royalty shall be** this subtracted from the nonconsenting owner's proportionate share of production**, with the remaining share allocated toward reimbursing consenting owners for the nonconsenting owner's share of costs** as described in subdivision 8(b)(i).

After recovery of the costs, the nonconsenting owner then owns **(owners always own their proportionate share, they are just not entitled to receiving them until development costs are ~~paid~~ recovered by the operator)** his or her full proportionate share of the wells, surface facilities, and production and then is ~~liable~~ **responsible** for further costs as if the nonconsenting owner had originally agreed to drilling of the wells.

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 **(Iron Range suggests calling this an "authorization for expenditure")** 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. Commissioner retains jurisdiction over pooling unit. During the period of cost recovery provided under this section, the commissioner retains jurisdiction to determine the reasonableness of costs of operation of the wells attributable to the interest of the nonconsenting owner. A nonconsenting owner can file an application with the commissioner for the review of the reasonableness of costs. Cost orders issued by the commissioner may be appealed pursuant to section 93.50.

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 8 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 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.

Section 11. 93.51711 DEFINITIONS (Iron Range recommends establishing a robust definitions section with terms recognized within the gas industry. Please see Appendix I, above)

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. **(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)**

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 E&P 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 12. 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 13. 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 **("general welfare" should be defined but is also a broad/vague term)** or prudent operator standards.

Section 14. 93.5174 GAS RESOURCE DEVELOPMENT PERMIT. (Iron Range recommends reviewing its comments in Sections IV and V, above)

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:

(1) an application fee of **$5,000**.

(2) 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;

(3) 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, as identified in subd. 8.

(4) 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

(5) 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;

(6) 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;

(7) 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;

(8) characterization of any exploration and production waste to be stored temporarily or permanently at a gas resource development location;

(9) plans for financial assurance instrument(s) addressing cost to close all gas resource development facilities and reclaim all gas resource development locations;

(10) 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 **("restoration" should be defined)** 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. (**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)**

(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) **(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)** for an application for a gas resource development permit. If the commissioner determines that the proposed amendment constitutes a substantial change **("substantial change" should be defined)** 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:

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

(2) 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 **(“public interests” is vague and should be defined, or alternatively, should be changed, e.g., “public health, safety, and welfare”).**

(3) 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 the event ~~**case**~~ of any **material** 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, **subject to extension**, in which to take corrective action and giving the permittee an opportunity to be heard thereon.

(4) 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 15. **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.
(2) A gas resource development location must not be located within 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;§

(c) state wilderness areas, with restrictions specified in Minnesota Statutes, section 86A.05, subdivision 6;

(d) Agassiz and Tamarac National Wilderness areas, and Pipestone and Grand Portage National monuments;

(e) state scientific and natural areas;

(f) within state peatland scientific and natural areas where such activities would 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;

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

(h) a state park, except if the park has been established as a result of its association with mining.

(3) A gas resource development location must not be allowed within or on the following, but activities that do not disturb the surface are allowed:

(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 disturbance 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.

(4) 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:

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

(a) 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;

(b) 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

(b) 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 thecommercial 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~~ **previous calendar 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. **(Much of the aforementioned information may be deemed proprietary and**

should be submitted confidentially or at least subject to a protective order)

Section 16. 93.5175 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.

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.

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. **(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.)**

(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. **(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.)**

(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. **(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?)**

Section 17. 93.5176 CONTESTED CASE. (Iron Range refers GTAC to its comments in Section V, above, for examples establishing a contested case hearing process and procedures)

Subdivision 1. **Petition for contested case hearing.** Any person owning property that will be affected by **(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.)** 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. **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.**

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 (**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.)**

(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. **(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.)**

(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; **(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.)**

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

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

(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. **(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.)**

(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: **(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.)**

(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 18. 93.5177 ENVIRONMENTAL REVIEW FEES. (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)

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 19. 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.

Subd. 2. **Criteria for financial assurance.** Financial assurance for reclamation and for corrective action must meet the following criteria:

(1) assurance of funds sufficient to cover the costs estimated under Subd. 3;

(2) assurance that the ~~**funds**~~ **financial instrument** will be available and made payable to the commissioner when **required for reclamation or corrective action** ~~**needed**~~;

(3) assurance that the financial instrument ~~**funds**~~ will be fully valid, binding, and enforceable under state and federal law;

(4) assurance that the financial instrument ~~**funds**~~ will not be dischargeable through bankruptcy;

(5) financial assurance shall 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 1 through 4 and 5 of this subdivision and in no case shall a corporate guarantee be approved as a stand-alone financial assurance ; and

(6)(5) all terms and conditions of the financial assurance must be approved by the commissioner.

Section 20. **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:

(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 **(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.)** or both, of any oil and gas locations upon which the person proposes to conduct oil and gas operations. The procedures for completing this cost estimate and its required elements shall be determined by the commissioner.

(6) ~~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.~~**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.**

(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. **(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).

(8) Financial assurance in the amount equal to the contingency reclamation cost **("contingency reclamation cost" must be defined)** 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.

(9) 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.

(10) 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** 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.

(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 **(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.

(12) 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**, in writing,** from the requirements of this part.

(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. **(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.)**

(14) The commissioner may deny, suspend, revoke or modify a gas resource development permit or assess civil penalties **(A schedule of fees for violations should be established)** if the permittee fails to comply with any portion of this part.

Section 21. 93.5179. APPEAL.

Any person aggrieved by any final order, ruling, or decision of the commissioner may obtain judicial **(A particular court should be identified)** review of such order, ruling, or decision under sections 14.63 to 14.69.

Section 22. 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 **(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.)**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.

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 resource**s** ~~**of**~~ **and** groundwater in an orderly, healthful, and reasonable manner.103I.005 **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.**

103I.005 DEFINITIONS. (Iron Range recommends developing a specific section containing a comprehensive list of definitions instead of presenting definitions throughout the broader statutory framework)

Subd. 9. **Exploratory boring. (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.~~

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.706 GAS WELLS.

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

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. **(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.)**

(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. **(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.)**

(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. **(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.)**

(d) If a licensee or certified representative under items (a) and (b) fails to submit all information required for renewal in 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 $76,000. **(It is unclear why this fee in this amount is necessary)**

(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. **(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)**

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. **(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).**

(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, 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, 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. **(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)**

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

(2) A certified representative must file an application and fee, under section 103I.706, subdivision 2, 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 **(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 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. **Gas well notification required.** (a) A gas well contractor must file the gas well notification, and fee, with the commissioner.

(b) 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. The person must submit a notification to the commissioner of health to construct a gas well after receiving permit approval from the commissioner of natural resources and prior to drilling or constructing a gas well.

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. **(See Iron Range's commend to MDH-3 and MDH-4, above)**

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. **Gas well 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 **(Iron Range recommends utilizing guidance documents applicable to gas development utilizing petroleum engineering and petroleum geology standard practices)**

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, 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.

(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.

(e) A person must not convert a gas well to any other type of well or boring and a person must not convert a well or boring of another type to a gas well.

(f) An exploratory boring is exempt from item (e) and may be converted to a gas well if constructed before enactment of section 103I.707 and constructed in compliance with section 103I.707.

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 of approved drilling fluids as provided in Subd. 7 for drilling and development of a gas well or a Class 2 injection well permit, authorized by the Environmental Protection Agency.

Subd. 5. **Hydraulic fracturing treatment.** ~~**Hydraulic fracturing treatment is prohibited in a gas well.**~~ **(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.)**

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. Markings must be rolled, stamped, or stenciled by the manufacturer.

(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 48 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 48 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 inner casing of a 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.

(m) The casing of a gas well must be covered with 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

<u>published in the State Register.</u>

<u>**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.</u>

<u>**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. **(Iron Range recommends the development of a statutory framework that contemplates oil and gas development)**</u>

<u>**EFFECTIVE DATE.** This section is effective the day following final enactment.</u>

116D.04 ENVIRONMENTAL IMPACT STATEMENTS (Iron Range recommends titling this section "Environmental Assessment Worksheets" instead of "Environmental Impact Statements," which are a particular form of environmental assessment)

<u>Subd. 16a. **Gas resource development projects.** Until a final rule is adopted, an environmental assessment worksheet must be prepared for any gas resource development project for which a permit is required by Minn. Statute 93.513 Subd 1. The Department of Natural Resources is the responsible governmental unit.</u>

Section __. Minnesota <u>Statutes</u> 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 <u>298.015</u> is exempt:

(1) deposits of ores, metals, ~~and~~ minerals<u>, gas, and oil in this state,</u> 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<u>, gas, or oil,</u> 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 <u>298.015</u> uses the property for mining, quarrying, producing, or refining ores, metals, ~~or~~ minerals<u>, gas, or oil</u>.

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

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, **Ranges** ~~bridges~~ of ~~bridge~~ **Range** companies, and all rights and privileges belonging or appertaining to the land, and all mines, iron ore, ~~and~~ taconite minerals<u>, other ores, minerals, metals, gas, or oil,</u> 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.j(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.i(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.e

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

Section __. Minnesota Statutes 2024, section 273.01, 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, metals, gas, and oil 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.

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

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. **(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.)**

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

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 paragraph (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, thebasis 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.e

(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).t

(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, 4humidity, 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, metal, gas, or oil, 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.c(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 or production of stone or peat, or the extraction or production of minerals, ores, metal, gas, or oil, when such substances are extracted from beneath the surface of the earth in Minnesota. Gas and oil shall have the meaning given to those terms in section 298.001, subdivisions 14 and 15.

(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 read:

Subd. 3a. **Producer**. "Producer" means a person engaged in the business of mining or producing iron ore, taconite concentrate, ~~or~~ direct reduced ore ~~in this state,~~ other ore, minerals, metals, gas, or oil in Minnesota, when such substances are extracted from beneath the surface of the earth in Minnesota.

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 drilling, extracting, separating, or beneficiating:

(1) gas or oil products subject to tax under section 298.015; and

(2) carried out by the entity, or affiliated entity, that drilled, extracted, separated, or beneficiated the gas or oil subject to tax under section 298.015.

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 that 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 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, minerals, gas, or oil, when such substances 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 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, produced ~~and~~or processed 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 processed 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.

(e)

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 or producing both iron ores, taconite concentrates, or direct reduced ore, and other ores, minerals, metals, gas or oil from the same mine, well, 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 paragraph (b), a~~A~~ person engaged in the business of mining, extracting, producing, or refining in Minnesota 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 as defined in section 298.016. The tax applies to all ores, metals, ~~and~~ minerals, gas, or oil mined, extracted, produced, or refined within the state of Minnesota, when such substances 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 helium products;

(ii) % of the gross proceeds for ______ products; and

(iii) % of the gross proceeds for ______ 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.

EFFECTIVEDATE. 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, and such product is produced from substances extracted, in their natural state, beneath the surface of the earth in

Minnesota, 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 paragraph (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~~paragraph (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 fair 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. s(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 accountfor 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.

EFFECTIVEDATE. 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, or 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, or 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, or 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, or 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 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, or 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 paragraph (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) Of 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 and production 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 and production 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.

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

Appendix I
Example Definitions

<u>Example New Mexico Definitions</u>

"Abate" means to investigate, contain, remove or mitigate water pollution. **17.15.2.7(A)(1) NMAC**
"Abatement" means the investigation, containment, removal or other mitigation of water pollution. **17.15.2.7(A)(2) NMAC**
Abatement Plan" means a description of operational, monitoring, contingency and closure requirements and conditions for water pollution's prevention, investigation and abatement. **17.15.2.7(A)(3) NMAC**
"AFE" means authorization for expenditure. **17.15.2.7(A)(7) NMAC**
"Allocated pool" means a pool in which the total oil or gas production is restricted and is allocated to various wells in the pool in accordance with proration schedules. **17.15.2.7(A)(9) NMAC**
"Allowable production" means that number of barrels of oil or cubic feet of gas the division authorizes to be produced from an allocated pool. **17.15.2.7(A)(10) NMAC**
"APD" means application for permit to drill. **17.15.2.7(A)(11) NMAC**
"Aquifer" means a geological formation, group of formations or a part of a formation that can yield a significant amount of water to a well or spring. **17.15.2.7(A)(14) NMAC**
"Bottom hole pressure" means the gauge pressure in psi under conditions existing at or near the producing horizon. **17.15.2.7(B)(9) NMAC**
"Bradenhead gas well" means a well producing gas through wellhead connections from a gas reservoir that has been successfully cased off from an underlying oil or gas reservoir. **17.15.2.7(B)(10) NMAC**
"Carbon dioxide gas" means noncombustible gas composed chiefly of carbon dioxide occurring naturally in underground rocks. **17.15.2.7(C)(1) NMAC**
"Casinghead gas" means a gas or vapor or both gas and vapor indigenous to and produced from a pool the division classifies as an oil pool. This also includes gas-cap gas produced from such an oil pool**. 17.15.2.7(C)(2) NMAC**
"Certified mail" or "certified mail, return receipt requested" means United States Postal Service Certified Mail or equivalent service that provides tracking and signature receipt, including Federal Express, United Parcel Service, or similar courier services. **17.15.2.7(C)(3) NMAC**
"Condensate" means the liquid recovered at the surface that results from condensation due to reduced pressure or temperature of petroleum hydrocarbons existing in a gaseous phase in the reservoir**. 17.15.2.7(C)(12) NMAC**
"Correlative rights" means the opportunity afforded, as far as it is practicable to do so, to the owner of each property in a pool to produce without waste the owner's just and equitable share of the oil or gas in the pool, being an amount, so far as can be practically determined, and so far as can be practicably obtained without waste, substantially in the proportion that the quantity of recoverable oil or gas under the property bears to the total recoverable oil or gas in the pool, and for the purpose to use the owner's just and equitable share of the reservoir energy. **17.15.2.7(C)(16) NMAC**
"Cubic feet of gas or cubic foot of gas" means that volume of gas contained in one cubic foot of space and computed at a base pressure of 10 ounces per square inch above the average barometric pressure of 14.4 psi (15.025 psi absolute), at a standard base temperature of 60 degrees fahrenheit. **17.15.2.7(C)(17) NMAC**
"Exempted aquifer" means an aquifer that does not currently serve as a source of drinking water,

and that cannot now and will not in the foreseeable future serve as a source of drinking water because: (a) it is hydrocarbon producing; (b) it is situated at a depth or location that makes the recovery of water for drinking water purposes economically or technologically impractical; or (c) it is so contaminated that it would be economically or technologically impractical to render that water fit for human consumption. **17.15.2.7(E)(5) NMAC**

"Facility" means a structure, installation, operation, storage tank, transmission line, access road, motor vehicle, rolling stock or activity of any kind, whether stationary or mobile. **17.15.2.7(F)(1) NMAC**

"Field" means the general area that at least one pool underlies or appears to underlie; and also includes the underground reservoir or reservoirs containing oil or gas. The words field and pool mean the same thing when only one underground reservoir is involved; however, field unlike pool may relate to two or more pools. **17.15.2.7(F)(2) NMAC**

"Fresh water" to be protected includes the water in lakes and playas (regardless of quality, unless the water exceeds 10,000 mg/l TDS and it can be shown that degradation of the particular water body will not adversely affect hydrologically connected fresh ground water), the surface waters of streams regardless of the water quality within a given reach, and underground waters containing 10,000 mg/l or less of TDS except for which, after notice and hearing, it is found there is no present or reasonably foreseeable beneficial use that contamination of such waters would impair. **17.15.2.7(F)(3) NMAC**

"Gas", also known as natural gas, means a combustible vapor composed chiefly of hydrocarbons occurring naturally in a pool the division has classified as a gas pool**. 17.15.2.7(G)(1) NMAC**

"Gas transportation facility" means a pipeline in operation serving gas wells for the transportation of gas, or some other device or equipment in like operation where the gas produced from gas wells connected with the pipeline or other device or equipment can be transported or used for consumption. **17.15.2.7(G)(5) NMAC**

"Gas well" means a well producing gas from a gas pool, or a well with a gas-oil ratio exceeding 100,000 cubic feet of gas per barrel of oil producing from an oil pool. **17.15.2.7(G)(6) NMAC**

"Ground water" means interstitial water that occurs in saturated earth material and can enter a well in sufficient amounts to be used as a water supply. **17.15.2.7(G)(10) NMAC**

"H2S" means hydrogen sulfide. **17.15.2.7(H)(6) NMAC**

"Inactive well" means a well that is not being used for beneficial purposes such as production, injection or monitoring and that is not being drilled, completed, repaired or worked over. **17.15.2.7(I)(4) NMAC**

"Injection well" means a well used for the injection of air, gas, water or other fluids into an underground stratum. **17.15.2.7(I)(4) NMAC**

"Log" means a systematic detailed and correct record of formations encountered in drilling a well. **17.15.2.7(L)(5) NMAC**

"Mineral estate" is the most complete ownership of oil and gas recognized in law and includes the mineral interests and the royalty interests. 17.15.2.7(M)(9) NMAC

"Mineral interest owner" means a working interest owner, or an owner of a right to explore for and develop oil and gas that is not subject to an existing oil and gas lease. **17.15.2.7(M)(10) NMAC**

"Minimum allowable" means the minimum amount of production from an oil or gas well that may be advisable from time to time to the end that production will repay reasonable lifting cost and thus prevent premature abandonment and resulting waste. **17.15.2.7(M)(11) NMAC**

"Official gas-oil ratio test" means the periodic gas-oil ratio test the operator performs pursuant to division order by the method and in the manner the division prescribes. **17.15.2.7(O)(1) NMAC**

"Operator" means a person who, duly authorized, manages a lease's development or a producing property's operation, or who manages a facility's operation. **17.15.2.7(O)(5) NMAC**

"Owner" means the person who has the right to drill into and to produce from a pool, and to appropriate the production either for the person or for the person and another. **17.15.2.7(O)(7) NMAC**

"Person" means an individual or entity including partnerships, corporations, associations, responsible business or association agents or officers, the state or a political subdivision of the state or an agency, department or instrumentality of the United States and of its officers, agents or employees. **17.15.2.7(O)(2) NMAC**

"Pool" means an underground reservoir containing a common accumulation of oil or gas. **17.15.2.7(O)(5) NMAC**

"Pressure maintenance" means the injection of gas or other fluid into a reservoir, either to maintain the reservoir's existing pressure or to retard the reservoir pressure's natural decline. **17.15.2.7(P)(9) NMAC**

"Produced water" means a fluid that is an incidental byproduct from drilling for or the production of oil and gas**. 17.15.2.7(P)(10) NMAC**

"Producer" means the owner of a well or wells capable of producing oil or gas or both in paying quantities. **17.15.2.7(P)(11) NMAC**

"Proration schedule" means the division orders authorizing the production, purchase and transportation of oil, casinghead gas and gas from the various units of oil or of gas in allocated pools. **17.15.2.7(P)(16) NMAC**

"Proration unit" means the area in a pool that can be effectively and efficiently drained by one well as well as the area assigned to an individual well for the purposes of allocating allowable production pursuant to a prorationing order for the pool. **17.15.2.7(P)(17) NMAC**

"Prospective spacing unit" means a hypothetical spacing unit that does not yet have a producing well. **17.15.2.7(P)(18) NMAC**

"Recomplete" means the subsequent completion of a well in a different pool from the pool in which it was originally completed. **17.15.2.7(R)(2) NMAC**

"Release" means breaks, leaks, spills, releases, fires or blowouts involving oil, produced water, condensate, drilling fluids, completion fluids or other chemical or contaminant or mixture thereof, including oil field wastes and gases to the environment. **17.15.2.7(R)(4) NMAC**

"Remediation plan" means a written description of a program to address unauthorized releases. The plan may include appropriate information, including assessment data, health risk demonstrations and corrective action or actions. The plan may also include an alternative proposing no action beyond the spill report's submittal. 17.15.2.7(R)(5) NMAC

"Responsible person" means the owner or operator who shall complete a division approved corrective action for pollution from releases. **17.15.2.7(R)(6) NMAC**

"Royalty interest owner" means the owner of an interest in oil and gas that does not presently entitle the owner to explore, drill or otherwise develop those minerals, including lessors, royalty interest owners and overriding royalty interest owners. Royalty interests are non-cost bearing. **17.15.2.7(R)(8) NMAC**

"Shut-in" means the status of a production well or an injection well that is temporarily closed, whether by closing a valve or disconnection or other physical means. **17.15.2.7(S)(5) NMAC**

"Spacing unit" means the area allocated to a well under a well spacing order or rule. **17.15.2.7(S)(9) NMAC**

"Temporary abandonment" or "temporarily abandoned status" means the status of a well that is inactive. **17.15.2.7(T)(3) NMAC**

"Top proration unit allowable for gas" means the maximum number of cubic feet of gas, for the proration period, the division allocates to a gas producing unit in an allocated gas pool. **17.15.2.7(T)(4) NMAC**

"Top proration unit allowable for oil" means the maximum number of barrels for oil daily for each calendar month the division allocates on a proration unit basis in a pool to non-marginal units. The division shall determine the top proration unit allowable for a pool by multiplying the applicable depth bracket allowable by the market demand percentage factor in effect. **17.15.2.7(T)(5) NMAC**

"TPH" means total petroleum hydrocarbons. **17.15.2.7(T)(6) NMAC**

"Tribal lands" means those lands for which the United States government has a trust responsibility to a native American tribe or a member of a native American tribe. This includes reservations, pueblo land grants, tribal trust lands and individual trust allotments. **17.15.2.7(T)(8) NMAC**

"Tribal leases" means those leases of minerals or interests in or rights to minerals for which the United States government has a trust responsibility to a native American tribe or a member of a native American tribe. **17.15.2.7(T)(9) NMAC**

"True vertical depth" means the difference in elevation between the ground level at the surface location of the well and the deepest point in the well bore. 17.15.2.7(T)(11) NMAC

"Underground source of drinking water" means an aquifer that supplies water for human consumption or that contains ground water having a TDS concentration of 10,000 mg/l or less and that is not an exempted aquifer. **17.15.2.7(U)(1) NMAC**

"Underproduction" means the amount of oil or the amount of gas during a proration period by which a given proration unit failed to produce an amount equal to that the division authorizes in the proration schedule. **17.15.2.7(U)(2) NMAC**

"Unit of proration for gas" consists of such multiples of 40 acres as may be prescribed by division-issued special pool orders**. 17.15.2.7(U)(3) NMAC**

"Unit of proration for oil" consists of one 40-acre tract or such multiples of 40-acre tracts as may be prescribed by division-issued special pool orders. **17.15.2.7(U)(4) NMAC**

"Unorthodox well location" means a location that does not conform to the spacing requirements division rules establish. **17.15.2.7(U)(5) NMAC**

"Well blowout" means a loss of control over and subsequent eruption of a drilling or workover well or the rupture of the casing, casinghead or wellhead of an oil or gas well or injection or disposal well, whether active or inactive, accompanied by the sudden emission of fluids, gaseous or liquid, from the well. **17.15.2.7(W)(6) NMAC**

"Well bore" means the interior surface of a cased or open hole through which drilling, production or injection operations are conducted. **17.15.2.7(W)(7) NMAC**

"Working interest owner" means the owner of an operating interest under an oil and gas lease who has the exclusive right to exploit the oil and gas minerals. Working interests are cost bearing. **17.15.2.7(W)(10) NMAC**

December 23, 2024

Commissioner Sarah Strommen
Minnesota Department of Natural Resources
500 Lafayette Road
Saint Paul, MN 55155

Commissioner Strommen:

Thank you for the opportunity to comment on the draft recommendations and statutory language developed by the Minnesota Gas Resources Technical Advisory Committee (GTAC) to create a temporary framework to regulate development of gas resources in our state.

MiningMinnesota is committed to promoting sustainable and environmentally responsible mineral production, including gas production, in our state. Our organization works with local citizens, businesses, and other organizations to grow Minnesota's economy and support domestic manufacturing and the supply chain through the responsible development of natural resources.

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.

There are three key items within the proposed regulatory framework that warrant further evaluation and discussion: 1) Conflation of exploration and production, 2) fee structures, and 3) requirements for project proposers to pay for environmental review.

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.

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.

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.

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.

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[1] that relies on helium, and we have celebrated the announcement of the Heartland Hydrogen Hub[2] 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.

Thank you for the opportunity to provide input on Minnesota's resource future.

Respectfully,

Julie C. Lucas

Julie Lucas
Executive Director, MiningMinnesota

[1] https://www.mnmedtech.co/
[2] https://mn.gov/governor/newsroom/press-releases/?id=1055-596141

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December 23, 2024

Minnesota Department of Natural Resources
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By electronic mail:
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Re: Input on Gas Resources Technical Advisory Committee Recommendations

Dear Gas Resources Technical Advisory Committee:

Pulsar Helium Inc. ("Pulsar") is a leading primary helium exploration and development company. We are excited to begin our fourth year of operations in Minnesota through our wholly owned Minnesotan subsidiary, Keewaydin Resources Inc., at its flagship Topaz Project in northeastern Minnesota. We have made tremendous progress with our appraisal well activity near Babbitt that we are doing under existing Minnesota regulations. 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.

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.

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.

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. Our comments incorporate comments we requested from Short Elliott Hendrickson Inc., our consulting firm, that has provided valuable assistance to us as we have planned and executed our activity in Minnesota and that also has tremendous experience with mining and other large project in Minnesota. We look forward to continued discussions with the GTAC agency, legislators, and others in coming months.

Existing Regulation – A Solid Foundation for Gas Regulatory Framework

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. Pulsar is proud that Keewaydin is already implementing a successful exploratory boring activity for potential non-hydrocarbon gas resources in Minnesota using existing local, state, and federal regulations and reviews.

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.

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. 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.

As is common industry exploration practice in Minnesota, we worked to minimize impacts to the greatest extent possible. As a result, we have done our exploration work to date with minimal impacts to the environment and received timely and productive reviews from the regulatory agencies. For example, during the planning stages for exploratory boring activity we identified a site layout and developed an installation plan to minimize environmental impacts. Our work to satisfy regulatory requirements for our work to date on both Jetstream#1 and Jetstream #2 included addressing these issues:

- Obtained from MDH an explorer's license[1] and identified the name of the responsible individual to supervise or oversee the location, construction, and sealing of exploratory borings on behalf of the explorer.
- Submitted application to MDH and passed the required MDH exam to obtain certification of the responsible individual. [2]
- Exploratory boring notification to MDH.[3]
- Compliance with MDH exploratory boring requirements.
- Wetland delineation work and No Loss Determination under the Minnesota Wetland Conservation Act.
- Clean Water Act (CWA) Section 404 Nationwide General Permit verification from the U.S. Army Corps of Engineers with CWA Section 401 Water Quality Certification from the Minnesota Pollution Control Agency (MPCA).
- Compliance with the existing Construction Stormwater Permit from the MPCA.
- U.S. Forest Service Special Use Permit for access across Forest Service land for access to mineral rights on private land.
- Lake County clearing and grading permit.

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.

Gas Exploration – Gas Exploration and Appraisal Rules Can Be Based on Minnesota's Well-Established Rules for Metallic Minerals Exploration

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

[1] MN Rules 4727.0250 EXPLORER RESPONSIBILITIES.

> An explorer is responsible for the construction, maintenance, and sealing of all exploratory borings completed under the explorer's license. The explorer may transfer the responsibility for maintenance and sealing to another explorer. The transfer of responsibility must be described in a written agreement, signed by both parties, that identifies which party is responsible for filing notification, maintaining the boring, and sealing the boring. A copy of the agreement must be submitted to the commissioner.

[2] MN Rule 4727.0500

[3] MN Rule 4727.0910

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.[4]

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.[5]

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. 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.

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.

Using our project as an example, the discovery of helium in 2011 by a drill crew searching for nonferrous minerals is the equivalent to discovery of a metallic mineral "mineral prospect." That well was drilled under MDH exploratory boring regulations and other state regulations that exist today. Hundreds of exploratory copper-nickel borings have been drilled throughout the region pursuant to applicable regulations, many at the same depth as the helium discovery, and Pulsar's site is the only place where a gas discovery was reported.

The next activity for a gas project is similar to "investigative drilling" for a nonferrous project. Again, hundreds of such exploratory borings have been drilled under existing regulations. Pulsar has conducted similar investigative drilling at the site with our Jetstream #1 well. Paraphrasing a public statement by DNR staff, that exploratory and appraisal work is necessary to go from knowing the gas is there to knowing how much gas is there. It must be completed to acquire the data needed to finalize a preliminary economic assessment, complete an economic feasibility

[4] Minn. Stat. 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;

[5] https://www.health.state.mn.us/communities/environment/water/wells/explore.html

[6] https://www.dnr.state.mn.us/lands_minerals/metallic_nf/development.html

study and, hopefully, begin the process to design a project for production. With that initial plan in hand, a gas project proposer and agencies will have the information needed to begin environmental review under state law and rules and begin a gas production facility permitting process.

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. 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.

As the temporary regulatory framework is moving from recommendations to final statutory language, all involved are learning more about gas wells. 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.

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. 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.

Gas Production: DNR, MPCA and EQB Temporary Framework Recommendations

Pulsar has committed significant resources to helium gas exploration in Minnesota. That work continues with promising results. We appreciate the excitement generated by the discovery of helium in Minnesota and our ongoing exploration work. 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.

The legislature tasked the DNR, MPCA and EQB with adopting rules related to gas production[7] and defined gas production in law: "'production' includes extraction and beneficiation from consolidated or unconsolidated formations in the state."[8] DNR is designated as the primary regulator of gas production activity, from taking responsibility for environmental review of proposed gas production projects to final reclamation. 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. 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.

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

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[7] Minn. Stat. 93.514 GAS AND OIL PRODUCTION RULEMAKING.

> (a) The following agencies may adopt rules governing gas and oil exploration or production, as applicable:
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> (1) the commissioner of the Pollution Control Agency may adopt or amend rules regulating air emissions; water discharges, including stormwater management; and storage tanks *as they pertain to gas and oil production*;
>
> * * *
>
> (3) the Environmental Quality Board may adopt or amend rules to establish mandatory categories for environmental review *as they pertain to gas and oil production*;
>
> (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 for the production of gas and oil;*
>
> (emphasis added).

[8] Minn. Stat. 93514 (c)

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.

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. 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.

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. 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.

Pooling, Spacing and Unitization

Pulsar understands the urgency to establish a proper temporary framework for gas development in Minnesota. 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. 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.

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.

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. Once the science has provided an idea of the anticipated drainage for one (1) vertical well and more information as to the size of the reservoir, field rules would be established with prescriptive setbacks through a formal public hearing with due notice. A Field Rule would define a reservoir over a considerable extent of land, the anticipated dominant gas and reasonable setbacks to protect offset mineral interests. 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.

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.

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.

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.

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. 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.

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.

<u>Fees on Gas Activity</u>

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.

We appreciate the opportunity to submit these comments and look forward to continued discussion in coming months.

Best regards,

Thomas Abraham-James
President and Chief Executive Officer
Pulsar Helium Inc.

Range Association of Municipalities and Schools
5525 Emerald Drive
Mt. Iron, MN 55768
rams@ramsmn.org • 218.748.7651

December 23, 2024

GTAC
500 Lafayette Road N, Box 45
St. Paul, MN 55155-4045

RE: GTAC Comments – Range Association of Municipalities and Schools

Commissioner Strommen:

On Behalf of the RAMS, the Range Association of Municipalities and Schools, representing 69 local unites of government including 27 cities, 27 townships, and 15 school districts in the Taconite Assistance Area of northeastern Minnesota, commonly known as the Iron Range, 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.

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.

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.

Sincerely,

Paul Peltier
Executive Director

Range Association of Municipalities and Schools (RAMS) *The organization represents more than 155,000 residents and 69 public sector units of government, including 27 cities, 15 public school districts, and 27 townships in the 13,000 square mile Taconite Assistance Area (TAA) of northeast Minnesota. As an organization, RAMS has represented the interests of the Iron Range region for 85 years.*

ONE RANGE ONE VOICE

RGGS Land & Minerals, LTD., L.P.

100 Waugh Drive – Suite 400 **Houston, Texas 77007**

December 23, 2024

By Email: GTAC@state.mn.us

Re: Regulatory Framework for Developing
Gas Resources in Minnesota

Ladies & Gentleman,

RGGS Land & Minerals, Ltd., L.P. ("RGGS") is a land and mineral owner in the state of Minnesota. As such, we have a vested interest in the regulations that will govern the development of gas discoveries in the state. 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. We have read the recommended rules and regulations and have the following comments.

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. 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. 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. 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. 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. 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.

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

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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.

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. 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.

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.

Sincerely,

Brianne Gravatt

Sr. Minerals Manager

(713)-951-0100 FAX: (713)-951-0191

USDA United States Department of Agriculture | Forest Service | Superior National Forest Supervisor's Office | 8901 Grand Avenue Place
Duluth, MN 55808
218-626-4300

File Code: 1500
Date: December 20, 2024

Minnesota Department of Natural Resources
ATTN: GTAC
500 Lafayette Road North
Box 45
St. Paul, MN 55155-4045

Thank you for the opportunity to comment on the Minnesota DNR's "*draft recommendations for a temporary framework to regulate gas resource development*". The Superior National Forest is pleased to offer comments in response to your invitation on December 2, 2024.

Specialists on the Superior National Forest have read and carefully considered the draft recommendations and have determined that the proposed rules represent a measured and common-sense approach to managing the state's mineral resources. We would like to offer some comments that may position the state to more effectively manage the leasing and permitting process:

GTAC Proposal	Superior National Forest Comment
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.
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.
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.

GTAC Proposal	**Superior National Forest Comment**
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.
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.
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
DNR-22, 23, 24, 25, 26, 27	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.
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.
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.
MPCA-1	At a minimum, permittees should adhere to MSHA and EPA standards regarding above ground storage tanks.

Again, thank you for the opportunity to comment. I appreciate you taking the time to consider the suggestions and views of the Superior National Forest and we appreciate your collaboration on minerals management.

If you have any questions regarding these comments on GTAC's proposed temporary regulatory framework, please contact our Forest Geologist Brian Longstreth via email (brian.longstreth@usda.gov) or by phone (218) 626-5347

Sincerely,

Thomas Hall
Forest Supervisor

cc: Shawn Olson, Eric Wirz, Brian Longstreth

Vema Hydrogen, Inc.
251 Little Falls Dr
Wilmington, DE 19808

December 16, 2024

Minnesota Department of Natural Resources
Gas Resource Technical Advisory Committee (GTAC)
GTAC@state.mn.us

Subject: Vema Hydrogen Feedback to GTAC's Working Recommendations and Statutory Language published November 15th, 2024

To Whom It May Concern,

Vema Hydrogen is a US company that is developing technology to produce low-carbon, stimulated geologic hydrogen. Vema is launching the first stimulated geologic hydrogen projects in the United States and is a world leader in this technology. Vema uses catalysts and subsurface stimulation to enhance and control natural hydrogen generating reactions from iron-rich geologic deposits. The process produces clean hydrogen gas for less than $1.00 per kg H2 levelized cost.

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.

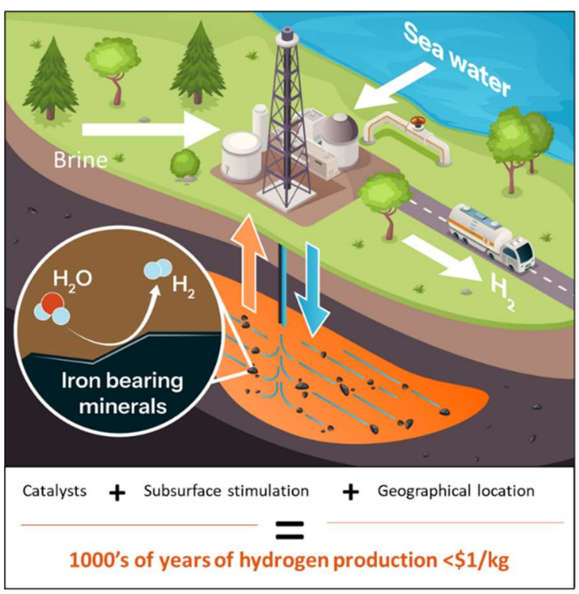

Figure 1; Schematics of Vema's technology. Water is injected into the target reactive formation. The hydrogen-producing reaction occurs, and hydrogen flows back to the surface through the same well.

Vema leadership’s combined experience includes expertise in geochemistry and catalytic hydrogen production, geologic hydrogen exploration, and exploration and development of gas resources in many states.

CEO

Pierre Levin

Mining engineer and geologist, serial entrepreneur, over 10 years in advanced subsurface technologies, former CEO of Hethos, a pioneer in Geologic hydrogen

CSO

Florian Osselin

Inventor of stimulated hydrogen. 1 patent, 18 peer-reviewed articles, including seminal paper on Stimulated H_2 in Nature (2022)

US Business Development

Colin McCulley

Engineer and operations leader with 17 years of experience in traditional energy sector, with experience developing upstream and midstream projects across the US.

This report includes feedback on the Working Recommendations and Statutory Language published on November 15th, 2024. Our feedback is specific to Vema’s stimulated geologic hydrogen process.

Thank you again for this opportunity to provide information. We look forward to supporting the GTAC’s work to adopt a gas resource development regulatory framework that protects natural resources and human health while also encouraging resource development that can provide reliable, clean energy for our collective future. Should you have any questions, please feel free to contact Colin McCulley at colin.mcculley@vema.earth or +1 713-702-2234.

Kind regards,

Pierre Levin

Pierre Levin, CEO

Feedback on Department of Natural Resources (DNR) recommendations

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

- This recommendation includes revising the Exploratory Boring definition to exclude its application to gas.

  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.

- 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 offices", 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-documents-review-uic-primacy-applications-and-program-revisions

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

- 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.

Recommendation DNR-7: The application fee and annual development fee for gas resource development projects should mirror comparable fees for nonferrous mine projects

- 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.

Feedback on Department of Health (MDH) recommendations:

Recommendation MDH-7: A person must not use a gas well to inject or dispose surface water, groundwater, or any other liquid, gas, or chemical.

- 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".

Recommendation MDH-8: A person is prohibited from hydraulic fracturing a gas well.

- 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 propagate fractures 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.

Feedback on Environmental Quality Board (EQB) recommendations:

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.

Feedback on Department of Revenue (DOR) recommendations:

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 different gases, minerals, and oils.

- Vema recommends that the Gross Proceeds Tax rate for Stimulated Geologic Hydrogen wells is distinct and different than the rate for Helium wells, and that the tax rate accounts for the commodity price for Hydrogen (~$1 per kg).

WATERLEGACY
Paula Goodman Maccabee, Executive Director and Counsel
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December 23, 2024

Sent electronically to GTAC@state.mn.us
Gas Resources Technical Advisory Committee

Minnesota Department of Natural Resources
Minnesota Department of Health
Environmental Quality Board
Minnesota Pollution Control Agency
Minnesota Department of Revenue

RE: Working Recommendations and Statutory Language for Permitting Gas Resources Development Under a Temporary Regulatory Framework

Dear Commissioners and Executive Staff,

The following comments are submitted on behalf of WaterLegacy, an organization formed to protect Minnesota water resources and communities. They are summarized below.

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.

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. Gas Resources Technical Advisory Committee (GTAC) agencies referenced the lack of knowledge regarding gas resources in Minnesota, other than the fact that helium was discovered in an exploratory boring in northeast Minnesota in 2024. The assessment would provide the basis for rulemaking.

3) The Legislature should adopt several Minnesota Department of Health (MDH) recommendations as a statutory framework prior to rulemaking. They set minimum standards and do not imply immediate permit issuance.

4) Gas resources regulation must provide environmental review, public accountability of agency decisions, and standards to protect health, safety, natural resources and reduce taxpayer financial risk as well as addressing ownership interests before permitting gas extraction or production.

Further, WaterLegacy believes that an additional public comment period should be allowed through January 2025. Public participation has so far been limited by the brief duration of the comment period and its timing in the midst of the holiday season.

1. The Legislature Should Refer Gas Resource Exploration and Production Regulation and Permitting for Rulemaking.

The Minnesota Department of Natural Resources (DNR) repeatedly cites nonferrous mining as an exemplar for its temporary gas extraction permitting process.[1] This is a false and misleading analogy.

A. Nonferrous Mining Has Required Analysis, Rulemaking, and Public Process.

The nonferrous mining analogy would require scientific assessment of the resource and rulemaking study and proceedings to address potential harms, benefits, and design requirements specific to various types of gas exploration and extraction prior to any permitting.

The Court of Appeals restated the history of nonferrous mining rule development in *Minn. Ctr. for Env'tl Advocacy v. Minn. Dep't of Nat. Res.* (*MCEA v. DNR*), A18-1956, 2019 WL 3545839 (Minn. Ct. App. Aug. 5, 2019). Nonferrous mining rules, Ch., 6132, were promulgated "pursuant to the legislature's direction in the mine land reclamation act," *id*. at *1, which was adopted in 1969 and authorized rulemaking. In 1973, the Legislature adopted Minn. Stat. § 93.481, which prohibited mining of metallic minerals without a permit. The DNR promulgated rules for ferrous mining in 1980 (codified in Minn. R. ch. 6130).

As explained in *MCEA v. DNR*, 2019 WL 3545839 at *2, in 1983 the Legislature precluded the DNR from issuing permits to mine nonferrous metallic minerals until it adopted rules for such mines (citing 1983 Minn. Laws ch. 270, § 5, at 1163, codified at Minn. Stat. § 93.481, subd. 6). "Over the next decade, the DNR engaged in study and rulemaking proceedings, and in March 1993, the DNR noticed adoption of final rules governing nonferrous metallic mineral mining." *Id*. (codified in Minn. R. ch. 6132). The court detailed the process of adopting appropriate rules for nonferrous mining:

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[1] *See* DNR recommendations DNR-3, DNR-7, DNR-9, DNR-10, DNR-13, DNR-14.

> Before noticing the final rules, the DNR conducted formal rule proceedings. That process included preparing a statement of need and reasonableness (SONAR); publishing notice of intent to adopt rules; accepting public comments; holding a hearing before an administrative-law judge (ALJ), who issued a report recommending adoption of the rules; and publishing notice of the final rules in the Minnesota State Register.

Id. It is misleading, if not irresponsible, to claim that proposed gas resource development without resource assessment, evidence, rules, or a public process corresponds to nonferrous mining rulemaking or practice.

B. <u>DNR Recommendations Fail to Protect the Environment or Tribal Rights</u>.

Second, DNR's recommendations for the structure of gas resources permitting would fail to protect Minnesota's environment or tribal authority and treaty-reserved rights.

<u>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</u>. (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.

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. <u>However, no permit, public process, or environmental review would be required when and if a proposer seeks mass commercial production of a gas resource</u>. (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).

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 (CO_2), with resultant climate issues if the CO_2 is vented to the atmosphere and acidity impacts if the CO_2 mixes with groundwater. If hydrogen is found in a gas deposit, it is highly explosive and could be radioactive.

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. <u>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</u>.

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.

C. <u>Proposed Recommendations Do Not Benefit or Protect Taxpayers</u>.

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]

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.

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.

2. The Legislature Should Require a Study of Minnesota Gas Resources.

In addition to rulemaking, the nonferrous mining precedent repeatedly cited in the GTAC recommendations entailed a legislatively-directed study of environmental risks and the development potential of nonferrous mining before permitting was even contemplated. It is clear in the GTAC discussion that Minnesota agencies and lawmakers know very little about the type, extent, or location of Minnesota's potential gas resources other than that one company reported an elevated helium sample in 2024.

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. 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

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[2] *See e.g.*, Headwaters Economics, *Oil and Natural Gas Fiscal Best Practices: Lessons for State and Local Governments*, Nov. 2012; available at https://headwaterseconomics.org/wp-content/uploads/Energy_Fiscal_Best_Practices.pdf.

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.

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.

Where there is a great deal at stake not only for revenue from a nascent industry, but for Minnesota's water quality, safety, and contributions to climate change, the Legislature should direct State agencies to initiate a rigorous and independent study before permitting gas exploration and extraction. Minnesota would be better off if we look before we leap.

3. The Legislature Should Adopt Basic Recommendations of the Minnesota Department of Health to Protect Health and Natural Resources.

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.

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.

4. Gas Resources Regulation and Permitting Must Protect Health, Safety, Natural Resources, and Climate Sustainability.

Gas resources regulation must provide environmental review, public accountability of agency decisions, and standards to protect health, safety, natural resources and reduce taxpayer financial risk, as well as addressing ownership interests before permitting gas extraction or production. The following important concepts should be reflected in any rulemaking or proposed gas resources permitting regime:

- 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.

- 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.[3]

[3] GTAC recommendations also support these requirements; DNR-12, EQB-1.

- 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.

- 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.

- 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).

- 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.

- 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.

- 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; policies related to state ownership of gas resources; and guidance to protect correlative interests of tribes on their reservations and tribal interests in exercise of treaty-reserved rights in ceded territories.

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.

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.

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).

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.

WaterLegacy appreciates the opportunity to comment in this matter, even with the time constraints that precluded a more detailed analysis. 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.

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.

Sincerely yours,

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