Directive 056

Release date: February 7, 2025

Effective date: February 7, 2025

Replaces previous edition issued February 8, 2024

Energy Development Applications and Schedules

Contents

Abbreviations

AAAQOs	Alberta ambient air quality objectives
ABSA	Alberta Boilers Safety Association
AEPA	Alberta Environment and Protected Areas
AER	Alberta Energy Regulator
AOA	area operating agreement
AOF	absolute open flow
AUC	Alberta Utilities Commission
BA	business associate
BMR	*Brine-Hosted Mineral Resource Development Rules*
CAPP	Canadian Association of Petroleum Producers
CBM	coalbed methane
CO_2	carbon dioxide
DSU	drilling spacing unit
EPEA	*Environmental Protection and Enhancement Act*
EPZ	emergency planning zone
ERP	emergency response plan
GRDR	*Geothermal Resource Development Rules*
H_2S	hydrogen sulphide
HVP	high vapour pressure
MOP	maximum operating pressure
NIA	noise impact assessment
NO_2	nitrogen dioxide
NO_x	nitrogen oxides
OGCR	*Oil and Gas Conservation Rules*

PFD	process flow diagram
REDA	*Responsible Energy Development Act*
SO_2	sulphur dioxide

1 Introduction

1.1 Purpose of This Directive

This directive contains the requirements for licence applications to construct and operate facilities, pipelines, or wells as part of an oil and gas, geothermal, or brine-hosted mineral resource development. The term "energy development" in this directive refers to any development under the *Oil and Gas Conservation Rules* (*OGCR*), the *Geothermal Resource Development Rules* (*GRDR*), and the *Brine-Hosted Mineral Resource Development Rules* (*BMR*). This directive is incorporated by reference into the *OGCR, GRDR*, *BMR*, and the *Pipeline Rules*. If a unique situation arises for an energy development proposal not covered in this directive, contact the AER for further direction.

Licensing requirements for geothermal development and brine-hosted mineral resource development are set out in their respective directives: *Directive 089: Geothermal Resource Development* and *Directive 090: Brine-Hosted Mineral Resource Development*. *Directive 056* requirements only apply when specified in *Directive 089* or *Directive 090*.

When an applicant files a licence application, it makes a commitment that it understands and will follow the appropriate participant involvement, audit, and technical requirements for energy developments as described throughout *Directive 056*, *Directive 089*, and *Directive 090*.

Directive 056 encompasses the legal requirements of licensees under the *OGCR*, *GRDR*, the *BMR*, the *Pipeline Rules*, and other regulations stipulated by the AER; however, approvals or licences from other government agencies may be required outside the *Directive 056* licensing process.

1.2 AER Requirements

Requirements and recommended practices are numbered sequentially within each section. "Must" indicates a requirement, and "recommends" and "expects" indicate a recommended practice.

- Requirements are those rules that industry has an obligation to meet.
- Expectations represent recommended best practices or guidelines.

1.3 What's New in This Edition

The directive has been revised to reflect use of category B091 for geothermal facilities regardless of the hydrogen sulphide (H_2S) and sulphur levels of the inlet gas stream (see section 5.3) and for conducting appropriate public consultation and notification. The classifications in table 7 have been revised to include geothermal wells (see "XPL" and "OTH").

As part of the continued implementation of the *Liability Management Framework* policy, references and requirements for the liability management rating (LMR) and licensee liability rating (LLR) programs have been removed. Section 5.6.2, about liability management, was updated.

1.4 How to Use This Directive

- Section 2, "Licence Applications," describes requirements and expectations that apply to all licence application types.
- Section 3, "Participant Involvement," describes two tiers of personal consultation and notification—required and expected. In addition, this section lists the information an applicant must include as part of its public information package and describes the AER's suggested process for dealing with outstanding public or industry concerns and objections.
- Section 4, "Application Audit Process," gives an overview of the audit process and the audit requirements that apply to all applicants.
- Section 5, "Facility Licence Applications," describes the application procedures specific to applying for a facility licence.
- Section 6, "Pipeline Licence Applications," describes application procedures specific to applying for a pipeline or pipeline installation licence.
- Section 7, "Well Licence Applications," describes application procedures specific to applying for a well licence.
- Section 8, "Additional Application Requirements (Special Circumstances)," describes additional application requirements specific to certain areas or circumstances.
- Appendix 1 contains definitions used in the directive.

1.5 Continuous Improvement

The AER gathers information on the efficiency and effectiveness of *Directive 056* and the licence application process through application auditing and data retention activities, as well as by soliciting stakeholder feedback.

As part of this commitment to continuous improvement, the AER anticipates the evolution of the requirements described in *Directive 056* in order to meet and exceed the needs of all stakeholders.

1.6 *Directive 056* Help

Links to frequently asked questions (FAQs), online schedules, and other information about ongoing *Directive 056* initiatives are available on the AER website at aer.ca.

If you have a question not covered in this directive or an FAQ, contact us at 403-297-8311.

2 Licence Applications

2.1 Overview

All applicants have the responsibility to understand and comply with legislative and regulatory requirements. The AER continues to work with applicants new to the licensing process or experiencing difficulties.

2.2 Before Filing a Licence Application

There are many factors to consider before filing an energy development licence application. Have all mineral rights been secured? Are there outstanding concerns or objections to the licence application? Are licences or approvals required from other agencies?

1) Before filing an energy development licence application with the AER, the applicant must

   a) obtain an AER BA code from Petrinex and licensee eligibility from the AER (see *Directive 067: Eligibility Requirements for Acquiring and Holding Energy Licences and Approvals*; all applicants and consultants must have a BA code);

   b) retain documentation to support the applicant's participant involvement program, including documentation of contact with or approval from other parties (see section 3 and tables 1–4); and

   c) retain copies of all design work and other supporting documentation for the application.

2.2.1 Business Associate Codes

BA codes, referred to as AER identification or operator codes in section 21(1) of the *Oil and Gas Conservation Act* (*OGCA*), are obtained from Petrinex. The AER cannot consider a licence application unless the applicant and all consultants have a valid BA code and the applicant has obtained licensee eligibility from the AER (see *Directive 067*).

2.2.2 Prelicensing Approvals and Variances

An applicant may seek a prelicensing ruling from the AER for the following components of a well licence application:

- hydrogen sulphide (H_2S) release rate assessment (section 7.7.15)
- critical well drilling plan variances *Directive 036: Drilling Blowout Prevention Requirements and Procedures* and *IRP Volume 1: Critical Sour Drilling*
- surface casing variance (section 7.7.11; *Directive 008*)
- drill-cutting samples (section 7.7.9)

Other types of variances for facility, pipeline, and well requirements (e.g., equipment spacing, measurement) are captured through the licence application process.

2) When filing an application that has a prelicensing approval or variance for surface casing, the applicant must identify so in its application.

If the applicant cannot meet a technical requirement, chooses to apply for a regulatory relaxation, cannot meet all participant involvements, outstanding concerns or objections exist, or proposes to implement new technology, the applicant must disclose the situation in its application. If there are outstanding concerns or objections to an exempt activity, the activity is no longer exempt from licensing, and an application disclosing the situation must be submitted.

2.3 Applicant Responsibilities

An applicant is responsible for all aspects of application development, including planning the energy development, planning and conducting participant involvement, retaining supporting documents, and submitting the application. Once a licence application is approved by the AER, the company becomes a licensee and bears responsibility for the construction, installation, and safe operation of the facility, pipeline, or well. The licensee is also responsible for decommissioning, dismantling, abandonment, and reclamation.

3) An applicant must obtain the appropriate AER licences before starting any site preparation, construction, or operation.

   Part 6, sections 11 and 12, of the *OGCA*; Part 4, section 6, of the *Pipeline Act*; and Part 2, section 9 of the *Mineral Resource Development Act* prohibit any preparatory or incidental operations on private or public lands before the applicant receives a well, facility, or pipeline licence or approval. This includes work such as access road construction; pipe stringing, bending, and welding; and facility equipment installation. Applicants must limit prelease activities to surveying and obtaining soil samples through shovel digs or auger samples no more than 5 to 8 centimetres (cm) in diameter.

4) An applicant or licensee is responsible for outcomes of actions conducted on its behalf by contracted personnel.

2.4 Submission Procedures

5) Facility, pipeline, and well audit submissions must be submitted electronically to the AER.

2.5 Incomplete Licence Applications

The AER cannot process an incomplete licence application. If an application has minor deficiencies, the AER may notify the applicant and request that corrections be submitted.

In the case of significant deficiencies, the AER will notify the applicant that the application is being closed and returned and why. The applicant may reapply by submitting a new, complete, and accurate energy development licence application.

6) Before reapplying, the applicant must assess the need to update its participant involvement program if a delay in filing or potential changes to the scope of the energy development require participant updates.

If the applicant designates a consultant to prepare and file an application on its behalf, the AER may communicate with the consultant during the processing of the application.

2.6 Checking the Status of a Licence Application

An applicant may review the status of its licence application through the AER website.

2.7 AER Licence Application Process

A licence issued under *Directive 056* is a licence to construct and operate a surface facility, pipeline, or well.

Numerous electronic checks are performed to determine the application's acceptability and the path for processing. This may include a preliminary technical screening that helps to identify issues that require further assessment.

Some applications may be set down for a hearing. For information on the AER's hearing process, see *Manual 003: Participant Guide to the Hearing Process*.

2.8 Application Disposition

The disposition of an application may occur through the application licensing process because of an AER hearing or because of the applicant's decision not to proceed with the energy development. Application disposition includes

- issuance of a licence by the AER,
- denial of a licence by the AER,
- closure of an application by the AER, and
- withdrawal of an application by the applicant.

3 Participant Involvement

3.1 Overview

"Participant involvement" is an umbrella term encompassing all aspects of public, industry, and regulator interactions and communications. While the three main participant groups in energy development are industry, the public, and the AER, it is recognized that other groups also have a stake in energy development.

While the outcomes of most participant involvement programs are successful, *Directive 056* provides the energy industry with requirements and expectations to assist industry in its participant involvement efforts. Applicants must consider requirements and expectations both in advance of submitting an application for energy development and throughout the life of that development.

Most land in Alberta carries two titles and two sets of rights. The surface title gives the landowner control of the land's surface and the right to work it. The mineral title gives the company or the person who owns the minerals under the surface the right to explore, work, or recover oil, gas, geothermal energy, or brine-hosted mineral resources.

Industry is required to develop an effective participant involvement program that includes parties who may be directly and adversely affected by the nature and extent of a proposed application. The development and implementation of this program must occur before filing an application and include distributing the applicant's information package and the required AER publications; responding to questions and concerns; discussing options, alternatives, and mitigating measures; and seeking confirmation of nonobjection through cooperative efforts. Industry is also expected to be sensitive to the timing constraints on the public (e.g., trapping, planting, harvesting, and calving seasons and statutory holidays).

The public is strongly encouraged to participate in ongoing issue identification, problem solving, and planning with respect to local energy developments. Early involvement in informal discussions with industry may lead to greater influence on project planning and mitigation of impacts. The public is also expected to be sensitive to the timing constraints on the applicant.

Participant involvement does not end with the issuance of a licence; it must continue throughout the life of a project. The development and creation of synergy groups at an early stage of the participant involvement program, especially in highly developed areas, will assist in fostering a collective and amenable approach to energy developments in the area.

All requirements and expectations detailed in this section apply to personal consultation and notification with all potentially directly and adversely affected persons, including First Nations and Métis. These requirements and expectations apply to the licensing of all new energy developments and all modifications to existing energy developments.

The Alberta Government issued *The Government of Alberta's First Nations Consultation Policy on Land Management and Resource Development* on May 16, 2005. Then in November 2007, to address how consultation with First Nations should occur in relation to certain land management and resource development activities, the government issued *The Government of Alberta's Guidelines on Consultation with First Nations on Land Management and Resource Development*. The consultation required by the guidelines is a process that is separate from the AER consultation requirements, and completion of the consultation guidelines should not be considered as a substitute for, or as completion of, the AER's consultation requirements.

3.2 Planning a Participant Involvement Program

Tables 1–4 set out the category type and the consultation and notification radii for planning a participant involvement program. The radii are the minimum. It is industry's responsibility to assess the area beyond a specified radius to determine if the radius should be expanded. The radius may need to be expanded to include public interest groups or others who have expressed an interest in development in the area.

Local authorities and the AER play an important part in the plan for orderly land use and should be involved at an early stage in planning an energy development and participant involvement program. Additionally, local authorities, AER staff, and the applicant's previous knowledge of the area may help identify needs in the community. Local AER staff are also available to assist in the proactive engagement of stakeholders and resolution of public issues. Project-specific participant involvement requirements are given in sections 3.6 through 3.9.

3.2.1 Who to Include

1) The applicant must develop and complete its participant involvement program before filing an energy development application.

2) The applicant must ensure that its participant involvement program includes those parties within the radii given in tables 1–4.

3) The applicant must include all parties with a direct interest in land, such as landowners, residents, occupants, other affected industry players, local authorities, municipalities, and other parties who have a right to conduct an activity on the land, such as Crown disposition holders.

4) The applicant must also include in the participant involvement program persons it is aware of who have concerns, regardless of whether they are inside or outside the radius of personal consultation and notification indicated in tables 1–4.

5) The applicant must allow participants a minimum of 14 calendar days to receive, consider, and respond to notification of the proposed development. The applicant may file an application before the 14-calendar-day period has ended if certain conditions have been met. Refer to section 3.3.2.

6) The applicant is expected to communicate with local residents and other operators and to develop an effective participant involvement program engaging parties at an early stage of planning. The applicant is also encouraged to contact synergy groups.

7) The applicant is expected to consult with or notify other parties that express an interest in the proposed development, whether located inside or outside the radius outlined in tables 1–4 and allow them the opportunity to obtain information specific to the proposed energy development and to understand its possible impacts.

8) The applicant is expected to document commitments made and have a process in place to monitor and follow up on commitments.

9) The applicant is expected to consider the timing constraints on the public (e.g., planting, harvesting, and calving seasons and statutory holidays).

10) The applicant is expected to minimize the cumulative impacts of energy development and show that they have applied good planning practices concerning the public and the environment.

11) If the proposed development is part of a larger project, the applicant is expected to discuss the entire project and explain how it complements other energy development in the area.

12) During the planning of its participant involvement program, the applicant will have assessed its need to reach the broader public and may determine that an information session or public open-house meeting is required. When holding public meetings or open houses, the applicant must disclose the same project-specific information as it would to those involved in personal consultation and notification. However, information sessions or public open houses may not be a substitute for meeting consultation requirements. Contact the AER for advice on how best to proceed.

In situations where it is intended to test a proposed well by flaring or incinerating gas, the applicant should consider expanding the resident notification to the distances specified in *Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting* for well test flaring:

- 1.5 kilometres (km) for oil wells
- 1.5 km for gas wells containing less than 10 moles per kilomole (mol/kmol) of H_2S
- 3.0 km for gas wells where the gas contains greater than or equal to 10 mol/kmol H_2S

3.2.2 What Information to Disclose

13) Information packages must be developed and distributed to all parties included in the participant involvement program. Information packages do not need to be sent to the AER for consultation or notification unless requested.

14) The applicant must provide information packages to those persons within the radii given in tables 1–4 and be prepared to discuss the project, if requested, with any person to whom an information package was sent.

15) If an area development plan has been developed, it must be distributed to those persons within the radii given in tables 1–4, and the information must be made available upon request from other interested parties.

16) The applicant's project-specific information package must provide the specific details of the proposed energy development.

17) The applicant must use appropriate language and terminology in the written materials so that the participants can clearly understand the details of the proposed development and the impact it may have upon them.

18) The following details must be included in the applicant's project-specific information package:

    a) applicant name and contact numbers for further information

    b) emergency contact number of the applicant or operator

    c) location of proposed energy development

    d) a description (category type) of the proposed energy development (e.g., well with no H_2S, coalbed methane [CBM] well, oil satellite with less than one tonne per day [t/d] sulphur inlet)

    e) need for the proposed development and explanation of how it fits with existing and future plans

    f) type of substances that will be processed, transported, or drilled for

    g) discussion of the presence of H_2S and associated setbacks as detailed in table 5, table 6, and table 10

h) discussion of the potential restrictions regarding developing lands adjacent to the proposed development, such as setbacks (section 2.110 of the *OGCR* and the *Subdivision and Development Regulation*; e.g., future surface improvements within 100 m of the wellhead may be subject to county/municipal development restrictions)

i) description of proposed on-site equipment

j) a description that meets the information requirements in *Directive 060* for any continuous flaring, incinerating, or venting

k) potential sources of emissions and odours during normal operating conditions (including trucking operations) and measures to control or eliminate them

l) proposed project schedule for construction and start-up

m) anticipated noise level and description of proposed mitigative measures, if required

n) traffic impacts, including types of vehicular traffic to be expected, duration, frequency, and dust control measures

o) the emergency planning zone (EPZ) (see *Directive 071: Emergency Preparedness and Response*)

p) derrick height (only when notifying private unregistered and unlighted airstrips)

q) the list of available AER public information documents and their availability from the applicant:

  i) the brochure *Understanding Oil and Gas Development in Alberta* and

  ii) all current AER EnerFAQs publications as set out on the AER website aer.ca

19) If any of the above-listed project details are not applicable to the proposed energy development, the applicant's project-specific information letter must explain why the detail is not applicable.

20) The applicant is expected to include any other information that would assist the participant in understanding the proposed development (e.g., soil information, water well testing, maps).

3.2.3 Personal Information

Applicants are reminded of their obligations under the *Personal Information Protection Act* (*PIPA*). That includes disclosing the need and purpose for collecting any personal information, the circumstances under which this information will be disclosed, and details regarding the security, retention, and ultimately the destruction of this information. The name of the person to be contacted regarding personal information collection and the company's privacy policy should also be provided, and all of these details should be consistent with the applicant's established privacy policy.

3.3 Implementing the Participant Involvement Program

21) The development and implementation of the participant involvement program must occur before filing an application with the AER. This includes

    a) distributing project-specific information packages and the AER public information documents;

    b) responding to questions and concerns;

    c) discussing options, alternatives, and mitigating measures; and

    d) seeking confirmation of nonobjection through cooperative efforts.

22) The applicant must always close the participant involvement loop, even if the application is withdrawn. This means that all parties included in the participant involvement program must continue to be included in all correspondence and information updates during the development, implementation, and outcome of the proposed project.

    a) If the scope of the project changes, such as a change to the surface location, the applicant must notify all parties included in the initial consultation program of the proposed change.

       If the project change results in the inclusion of new participants, the applicant must meet all participant involvement requirements in regard to the new participants as well.

    b) The applicant must notify all parties (public and industry) if it has decided not to proceed with the proposed project after having initiated a participant involvement program.

    c) The applicant must notify all participants (public, industry, and regulatory) when a change in circumstances does not allow previous commitments to be met.

23) If the applicant is unable to fulfil all *Directive 056* participant involvement requirements, it must indicate so in its application and demonstrate the efforts made to engage the participants.

3.3.1 Personal Consultation and Confirmation of Nonobjection

24) Personal consultation is intended to inform parties of the nature and extent of the proposed application. Questions raised during the discussion of the proposed energy development should alert the applicant to potential concerns and objections. Through discussions, the applicant may be able to confirm nonobjection. If not, the applicant must identify this in its application. The applicant must fulfil the personal consultation and confirmation of

nonobjection requirements for the radii in tables 1–4. It is the applicant's responsibility to determine if the recommended radii need to be expanded for the proposed development.

25) The applicant must conduct face-to-face visits or telephone conversations with all identified parties.

26) A company representative with full knowledge of the overall plans and direction of future development options must be available to answer questions either in person or by telephone.

27) The applicant must use appropriate language and terminology both in conversations and written materials so that the participants can clearly understand the details of the proposed development and the impacts it may have upon them.

28) The applicant must provide information packages to those persons within the radii given in tables 1–4 and be prepared to discuss the project as necessary.

29) The applicant must provide the following information when personal consultation is required:

 a) the applicant's project-specific information package

 b) the letter from the Chairman of the AER

 c) the AER brochure *Understanding Oil and Gas Development in Alberta*

 d) the AER publication *EnerFAQs: Proposed Oil and Gas Development; A Landowner's Guide*

 e) the AER publication *EnerFAQs: Expressing Your Concerns – How to File a Statement of Concern About an Energy Resource Project*

 f) any other information that would assist a participant in understanding the proposed development (e.g., soil information, water well testing, maps)

30) The applicant must offer the participants copies of other AER EnerFAQs publications that relate to the proposed energy development and document its distribution for audit purposes.

31) The required information packages may be distributed during the personal consultation meeting or forwarded later as follow-up. Packages may be forwarded by courier, mail, fax, email, or other means as agreed on by the parties.

32) If the participant does not want a copy of the required information packages, the applicant must document the refusal for audit purposes.

33) When confirmation of nonobjection is required, the applicant must ensure that there are no unresolved concerns or objections by obtaining written or verbal confirmation from the participant that they have no objection to the AER issuing a licence for the proposed energy development.

34) The applicant must keep a log of the dates that personal consultation and confirmation of nonobjection occurred, when materials were distributed and received, and by whom.

35) The applicant is accountable for the outcomes of personal consultation completed on its behalf by contracted personnel. Therefore, the applicant must ensure that individuals conducting personal consultation on its behalf

    a) possess a sound understanding of regulatory requirements and expectations for participant involvement and

    b) use appropriate language and terminology in the written materials so that the participants can clearly understand the details of the proposed development and the impact it may have upon them.

3.3.2 Notification

Notification differs from personal consultation in that the initial communication may take place through written correspondence rather than through face-to-face or telephone conversations.

Ensuring that participants have received information packages will reduce the possibility of late (post-approval) concerns or objections and requests for regulatory appeal under section 38 of the *Responsible Energy Development Act* (*REDA*). Applicants may choose to use registered mail or courier to ensure that the participants receive the information packages or to document attempts made to involve the participants.

36) The applicant must fulfil the notification requirements for the radii in tables 1–4. It is the applicant's responsibility to determine if the recommended radius of notification needs to be expanded for the proposed development.

    Notifying Crown disposition holders within the proposed facility site, well site, access road, or pipeline right-of-way is also required. The applicant may exclude Crown disposition holders such as oil and gas industry participants if they are not impacted by setback requirements.

37) If the notified party indicates it would prefer personal consultation, a company representative with full knowledge of the overall plans and direction of future development options must be available to answer questions either in person or by telephone.

38) The applicant must use appropriate language and terminology in conversations and written materials so that the participants can clearly understand the details of the proposed development and the impact it may have upon them.

39) The applicant must provide a copy of its project-specific information package and the letter from the Chairman of the AER and offer the participants copies of

a) the AER brochure *Understanding Oil and Gas Development in Alberta*,

b) the AER publication *EnerFAQs: Proposed Oil and Gas Development; A Landowner's Guide*,

c) the AER publication *EnerFAQs: Expressing Your Concerns – How to File a Statement of Concern About an Energy Resource Project*, and

d) all current AER EnerFAQs publications as set out on the AER website.

40) The applicant must allow a minimum of 14 calendar days for the participants to receive, consider, and respond to the notification and be prepared to discuss the project as necessary before submitting an application. This also applies to any project updates that may have been forwarded since the original package was distributed.

a) If the applicant has fulfilled the personal consultation and confirmation of nonobjection requirements in lieu of the notification requirements, the applicant may file the energy development application once it has completed personal consultation and acquired confirmation of nonobjection.

b) If the applicant is aware that an information package was not received by a required party, the applicant must demonstrate its efforts to contact the party.

41) The applicant is accountable for the outcome of notification completed on its behalf by contracted personnel. Therefore, the applicant must ensure that individuals conducting notification on its behalf

a) possess a sound understanding of regulatory requirements and expectations for participant involvement and

b) use appropriate language and terminology in the written materials so that the participants can clearly understand the details of the proposed development and the impact it may have upon them.

3.3.3 Extended Absences

In some instances, landowners and residents may be away for extended periods, such as on vacation, or they may reside out of the province.

42) When the applicant must personally consult with participants and is unable to do so, the applicant is expected to use courier or registered mail to send letters and information packages.

3.3.4 Addressing Concerns/Objections and Alternative Dispute Resolution

Directive 056 recommends that all applicants address and attempt to resolve concerns and objections before filing the application with the AER.

43) At any time during the planning, construction, and operation of a project, the applicant must attempt to address unresolved concerns and objections raised by potentially affected or interested parties, reconcile differences where possible, and obtain confirmation of nonobjection.

44) The applicant must attempt to address all questions, concerns, and objections regarding the proposed development before filing and during the review of the energy development application, regardless of whether the party involved is inside or outside the radii given in tables 1–4.

    To address unresolved concerns and objections, the applicant may choose to

    - meet with objectors and attempt to resolve issues through informal "kitchen table" discussions,
    - engage the AER's alternative dispute resolution program,
    - pursue resolution through a more formalized third-party mediation process, or
    - request an AER disposition, such as a public hearing; the applicant may request an AER hearing in parallel with the alternative dispute resolution process.

    If concerns and objections cannot be resolved and the applicant intends to proceed with the project, the applicant must disclose so in its application.

45) The applicant must include a written summary of any unresolved concerns and objections, including a discussion of how the applicant intends to mitigate the concerns and objections raised.

46) The applicant and the objector are expected to consider using the AER's alternative dispute resolution program to mitigate unresolved concerns and objections.

3.3.4.1 Compensation

This section does not apply to geothermal energy development because geothermal development is not covered by the *Surface Rights Act*. Matters of compensation are not within the AER's jurisdiction. If a surface rights agreement is unobtainable from the landowner solely due to compensation issues, the applicant may request that the AER issue the licence to allow the applicant to apply to the Land and Property Rights Tribunal for a right-of-entry order.

47) The applicant may proceed with its licence application if the landowner confirms in writing that compensation is the only issue and there are no concerns/objections to the AER issuing a licence so that the parties may proceed to the Land and Property Rights Tribunal.

48) If landowner confirmation as described above cannot be obtained or if there are unresolved compensation issues identified by participants other than the surface landowner, the applicant must disclose that in its application.

3.4 Documenting the Participant Involvement Program

It is in the applicant's best interest to understand the audit requirements for participant involvement. The applicant should develop an audit documentation package early and build it throughout the process.

49) The applicant must retain communication logs, records of confirmation of nonobjection letters, and registered mail and courier tracking for audit purposes.

50) The applicant must retain personal consultation and notification documents for audit purposes.

51) The applicant must retain documentation of resolution of concerns and objections that occurred before filing an application.

52) The applicant must supply all documentation to the AER upon request.

3.5 Expiry of the Personal Consultation and Notification Program

All facility, pipeline, and well licences issued under this directive typically expire one year from date of issue if not acted on (i.e., if clearing or construction has not begun). If a licence expires, any associated personal consultation and notification also expires.

53) If a licence expires and the licensee intends to proceed with the project, the licensee must consult again on the proposed project or be able to demonstrate that personal consultation and notification updates have been conducted.

54) A personal consultation and notification program is only valid for one energy development. Therefore, the applicant must initiate a new or updated personal consultation and notification program for additional applications and licence amendment applications.

In some instances, the complexity of a project may have required that personal consultation and notification be initiated well in advance of the licence application being filed.

55) The participant involvement program must be current when the application is filed, regardless of when the program was initiated.

56) If the personal consultation and notification program is initiated well in advance of the application submission date, the applicant is required to continue personal consultation and notification throughout the application process by providing participants with status updates on the proposed development. Project status updates must be provided if one year has elapsed since the initial consultation.

If the AER determines that the initial communication was incomplete or that the consultation is no longer current, the applicant may be directed to fulfil participant involvement requirements.

57) In cases where concerns or objections have been expressed, the applicant is expected to close the participant involvement loop by explaining the outcome of the application to those parties included in the participant involvement program. This should include what will be done next and an explanation of how the applicant will meet any commitments made during the participant involvement process, with an emphasis on ongoing information sharing.

58) The applicant must attempt to address concerns and objections and answer questions raised by members of the public, industry, government representatives, First Nations, Métis, and other interested parties throughout the life of a project.

3.6 Additional Participant Involvement Requirements for Facilities

3.6.1 Consultation and Notification Requirements by Facility

The consultation and notification requirements for each facility are listed in table 1. The category type of facility is dependent on the H_2S and sulphur content of the inlet gas stream.

59) The applicant must identify the correct type for the proposed facility project and perform all associated consultations and notifications.

60) For all licence amendments listed in section 5.4 of *Manual 012*, full participant involvement requirements must be met, or the application must be filed as nonroutine. This includes those amendments described as being not mandatory.

Table 1. Consultation and notification requirements by facility type

Category	Name	Type	Description	Personal consultation and confirmation of nonobjection	Notification
B	Facilities <0.01 mol/kmol H_2S in inlet stream	001	Single-well facility and brine-hosted mineral battery—single well	• Landowner and occupants • Residents within 0.3 km	• Local authority • Crown disposition holders
	Facilities <0.01 mol/kmol H_2S in inlet stream	010 011 020 030 031 040	Gas processing plant Gas fractionation plant Gas battery—multiwell Oil/mineral battery—multiwell Bitumen battery—multiwell Compressor station	• Landowner and occupants • Residents within 0.5 km	• Crown disposition holders • Local authority • Landowners, occupants, and urban authorities within 1.5 km
		070 071	Oil satellite—multiwell Bitumen satellite—multiwell	• Landowner and occupants	• Crown disposition holders
		080	Custom treating facility	• Landowner and occupants • Residents within 0.5 km	• Crown disposition holders • Local authority • Landowners, occupants, and urban authorities within 1.5 km
		090 091	Injection/disposal facility—water Injection/disposal—enhanced oil recovery or geothermal facility	• Landowner and occupants • Residents within 0.5 km	• Crown disposition holders • Local authority • Landowners, occupants, and urban authorities within 1.5 km When H_2S ≥0.1 mol/kmol: • Residents in the EPZ
		200	Straddle plant	• Landowner and occupants • Residents within 0.5 km	Crown disposition holders • Local authority • Landowners, occupants, and urban authorities within 1.5 km
C	Facilities <1 t/d sulphur inlet	300 301 302 310 311 320 321 330 331	Gas processing plant Gas fractionation plant Straddle plant Gas battery—single well Gas battery—multiwell Oil/mineral battery—single well Oil/mineral battery—multiwell Bitumen battery—single well Bitumen battery—multiwell	• Landowner and occupants • Residents within 1.5 km	• Crown disposition holders • Local authorities • Landowners, occupants, and urban authorities within 2.0 km When H_2S ≥0.1 mol/kmol: • Residents in the EPZ

Category	Name	Type	Description	Personal consultation and confirmation of nonobjection	Notification
		340	Compressor station		
		350 351	Oil satellite—single or multiwell Bitumen satellite—single or multiwell	• Landowner and occupants	• Crown disposition holders When H_2S ≥0.1 mol/kmol: • Residents in the EPZ
D	Facilities >1 t/d sulphur inlet	400 401 410 411 420 421 430 431 440	Gas processing plant Gas fractionation plant Gas battery—single well Gas battery—multiwell Oil/mineral battery—single well Oil/mineral battery—multiwell Bitumen battery—single well Bitumen battery—multiwell Compressor station	• Landowner and occupants • Residents within 1.5 km	• Crown disposition holders • Local authority • Landowners, occupants, and urban authorities within 3.0 km When H_2S ≥0.1 mol/kmol: • Residents in the EPZ
		450 451	Oil satellite—single or multiwell Bitumen satellite—single or multiwell	• Landowner and occupants	• Crown disposition holders When H_2S ≥0.1 mol/kmol: • Residents in the EPZ
E	Sulphur recovery facilities	600	Gas processing plant	• Landowner and occupants • Residents within 1.5 km	• Crown disposition holders • Local authority • Landowners, occupants, and urban authorities within 5.0 km When H_2S ≥0.1 mol/kmol: • Residents in the EPZ

3.6.2 Exempt Activities and Facilities

61) Although no application is required under this directive for certain exempt activities and facilities (see sections 5.4.1 and 5.4.3), the company must provide a project-specific information package to landowners, occupants, and residents who may be directly and adversely affected by the activity.

Oil Sands Processing Plants

Stakeholder notification that has been completed as part of a *Directive 023* application for a new in situ oil sands project or an amendment to an existing project satisfies the participant involvement requirements for any related *Directive 056* application for facilities within the AER-approved in situ oil sands project area.

3.7 Other Participant Involvement Requirements for Facilities

62) The applicant must ensure that participant involvement requirements are met for the radii set out in table 1.

63) The applicant must meet the information requirements as part of personal consultation and notification for all facility licence applications.

64) For category C, D, and E facilities, the applicant must identify and notify all mineral reserve owners and licensees of existing similar facilities within the recommended radius (see table 2).

    The applicant must provide all mineral reserve owners and licensees with a written overview of the proposed facility—including location, type, and design capacities—and the anticipated timing for application submission. The onus is then on these parties to raise any concerns or objections to the proposal with the applicant and the AER.

65) For facilities not listed in table 2, the AER does not prescribe a radius for industry notification. Applicants are expected to determine what is a reasonable geographic area for industry notification.

66) The AER does not prescribe the area the applicant must investigate. However, the applicant is expected to consider investigation parameters similar to those in table 2 and discuss the proposal with licensees of similar facilities.

67) When the applicant notifies other licensees, it must continue to include these licensees in updates during the licensing process (i.e., close the participant involvement loop; see section 3.3).

Table 2. Facility industry notification requirements

Proposed facility	Mineral reserve owners	Facility licensees
New gas processing plant (categories C and D)	5 km	15 km
Gas processing plant (category E)	5 km	15 km
Oil and bitumen production facilities (category D)	N/A	2 km

3.7.1 Setback Requirements

68) The applicant must address the issue of the setback restrictions in table 5 during its participant involvement process.

3.7.2 Noise Requirements

69) Applicants must discuss noise matters with area residents during the design, construction, and operating phases of the facility.

3.7.3 Licence Expiry

70) Licensees must conduct full participant involvement work in order to apply to extend the expiry date of a facility licence or a temporary facility licence.

71) Before initiating new construction, when a licence is nearing expiry, the licensee must conduct a new search for residents and landowners and determine if any new issues have arisen since granting the licence.

3.7.4 Licence Extensions

72) To get an extended expiry date for an applied-for licence, the applicant must update its participant involvement program before it acts on the licence.

73) To get an extended expiry date for an existing licence, the licensee must update its participant involvement program before it acts on the licence.

3.8 Additional Participant Involvement Requirements for Pipelines

3.8.1 Consultation and Notification Requirements for Pipelines

The consultation and notification requirements for pipelines are listed in table 3. The category and type for a pipeline depends on the pipeline's licensed substance, H_2S content of the substance, H_2S partial pressure, pipe diameter, and the table 6 level designation.

74) The applicant must identify the correct type for the proposed pipeline and perform all associated consultations and notifications noted in table 3.

75) The applicant must meet the information requirements as part of personal consultation and notification for all pipeline licence applications.

76) The AER does not prescribe the geographic area the applicant must investigate for industry notification. However, the applicant is expected to discuss the proposal with licensees of similar pipelines.

The applicant is expected to provide interested oil and gas reserve owners and licensees with a written overview of the proposed pipeline. The onus is then on these parties to raise any concerns or objections to the proposal with the applicant and the AER. The AER expects this contact to precede public consultation and notification.

The licensee does not require AER approval before conducting a pipeline abandonment, discontinuance, removal, or line split. Some of these activities require the licensee to conduct participant involvement before starting the activity. If there are no outstanding concerns about the proposed activity raised during the participant involvement period, the licensee may proceed. Upon completion, the licensee applies to amend the licence.

77) The licensee must submit an application disclosing any outstanding concerns raised about the proposed activity during the participant involvement period and obtain approval under *Directive 056* before starting the proposed activity.

The participant involvement requirements for pipeline activities that require a licence amendment are listed in section 3.8.2.

Stakeholder notification that has been completed as part of a *Directive 023* application for a new in situ oil sands project or an amendment to an existing project satisfies the participant involvement requirements for any related *Directive 056* application for the associated pipelines within the AER-approved in situ oil sands project area.

Table 3. Consultation and notification requirements by pipeline type

Category	Name	Type	Description	Personal consultation and confirmation of nonobjection	Notification
B	Pipelines, gas (non-sour service[1])	100	Natural gas ≤323.9 mm OD	• Landowners and occupants of the right-of-way	• Crown disposition holders • Local authorities along the right-of-way • Urban authorities within 1.5 km • For category type B101, B111, and B121, landowners and occupants within 0.2 km When H_2S ≥0.1 mol/kmol: • Residents in the EPZ
		101	Natural gas >323.9 mm OD		
	Pipelines, oil effluent (non-sour service[1] and ≤10 mol/kmol H_2S)	110	Oil effluent ≤323.9 mm OD		
		111	Oil effluent >323.9 mm OD		
	Pipelines, other	120	Other ≤323.9 mm OD		
		121	Other >323.9 mm OD		
	Pipeline downstream facilities	130	Pipeline tank farm	• Landowner and occupants	• Crown disposition holders • Local authorities
		131	Pipeline oil loading or unloading terminal		

Category	Name	Type	Description	Personal consultation and confirmation of nonobjection	Notification
		132 133	Compressor station Pump station	• Residents within 0.5 km	• Landowners, occupants, and urban authorities within 1.5 km When H_2S ≥0.1 mol/kmol: • Residents in the EPZ
C	Pipelines, gas (sour service[1] but ≤10 mol/kmol H_2S)	380 381	Sour service natural gas ≤323.9 mm OD Sour service natural gas >323.9 mm OD	• Landowners and occupants of the right-of-way	• Crown disposition holders • Local authorities along the right-of-way • Urban authorities within 1.5 km • For category type C381 and C383, landowners and occupants within 0.2 km When H_2S ≥ 0.1 mol/kmol: • Residents in the EPZ
	Pipelines, oil effluent (sour service[1] but ≤10 mol/kmol H_2S)	382 383	Sour service oil effluent ≤323.9 mm OD Sour service oil effluent >323.9 mm OD		
	Pipeline upstream facilities	384	Pipeline line heater	• Landowner and occupants	• Crown disposition holders When H_2S ≥ 0.1 mol/kmol: • Residents in the EPZ
D	Pipelines, sour natural gas or oil effluent >10 mol/kmol H_2S[2]	452 453	Level 1 sour natural gas ≤323.9 mm OD Level 1 oil effluent ≤323.9 mm OD Level 1 sour natural gas >323.9 mm OD Level 1 oil effluent >323.9 mm OD	• Landowners and occupants of the right-of-way	• Crown disposition holders • Local authorities along the right-of-way • Landowners, occupants, and residents within 0.5 km • Urban authorities within 1.5 km When H_2S ≥0.1 mol/kmol: • Residents in the EPZ
		454 455	Level 2 sour natural gas ≤323.9 mm OD Level 2 oil effluent ≤323.9 mm OD Level 2 sour natural gas >323.9 mm OD Level 2 oil effluent >323.9 mm OD	• Landowners and occupants of the right-of-way and within 0.1 km setback	• Crown disposition holders • Local authorities along the right-of-way • Landowners, occupants, and residents within 0.5 km • Urban authorities within 2.0 km When H_2S ≥ 0.1 mol/kmol: • Residents in the EPZ
		461 462	Level 3 sour natural gas ≤323.9 mm OD Level 3 oil effluent ≤323.9 mm OD Level 3 sour natural gas >323.9 mm OD	• Landowners and occupants of the right-of-way and within 0.1 km setback	• Crown disposition holders • Local authorities along the right-of-way

Category	Name	Type	Description	Personal consultation and confirmation of nonobjection	Notification
			Level 3 oil effluent >323.9 mm OD		• Landowners, occupants, and residents within 1.5 km • Urban authorities within 3.0 km When H_2S ≥ 0.1 mol/kmol: • Residents in the EPZ
		463	Level 4 sour natural gas ≤323.9 mm OD Level 4 oil effluent ≤323.9 mm OD	• Landowners and occupants of the right-of-way and within 0.1 km setback	• Same as Level 3 unless otherwise specified by the AER
		464	Level 4 sour natural gas >323.9 mm OD Level 4 oil effluent >323.9 mm OD		
	High-vapour-pressure pipelines	530	HVP pipelines	• Landowners and occupants of the right-of-way	• Crown disposition holders • Local authorities along the right-of-way • Landowners, occupants, and residents within 0.2 km • Urban authorities within 1.5 km
	Pipeline upstream facilities	531	Pipeline line heater	• Landowners and occupants	• Crown disposition holders When H_2S ≥0.1 mol/kmol: • Residents in the EPZ

[1] See clause 16 of *CSA Z662* for the definition of sour service.

[2] An H_2S release volume must be calculated for all sour natural gas or oil effluent pipelines containing greater than 10 mol/kmol H2S. See section 6.5.2 and table 6 for more information.

3.8.2 Participant Involvement Requirements for Pipeline Licence Amendments

3.8.2.1 Not Constructed Pipeline

78) If the licensee does not intent to construct a pipeline for which a permit has been issued, the licensee must complete the following actions before filing its application:

a) Provide notification to landowners and occupants along the entire pipeline right-of-way and within associated setbacks.

b) Provide notification to residents within the distances specified in table 3 if a category D pipeline.

3.8.2.2 Substance or H_2S Change

79) If the substance conveyed changes or its H_2S content change results in a setback increase or the pipeline changes to category D, the licensee must complete the following actions before filing its application:

   a) Conduct personal consultation with confirmation of nonobjection with landowners and occupants along the entire pipeline right-of-way and within associated setbacks.

   b) Provide notification to residents within the distances specified in table 3 if a category D pipeline.

80) If the substance conveyed changes or its H_2S content change results in a setback decrease or elimination, the licensee must notify all landowners and occupants along the entire pipeline right-of-way and within associated setbacks before submitting its application.

81) If the substance conveyed changes or its H_2S content change results in a sour gas EPZ change, the licensee must notify the residents within the existing and new EPZs before applying for a licence amendment.

3.8.2.3 Maximum Operating Pressure Change

82) If the MOP change results in a setback increase, the licensee must complete the following actions before filing its application:

   a) Conduct personal consultation with confirmation of nonobjection with landowners and occupants along the entire pipeline right-of-way and within associated setbacks.

   b) Provide notification to residents within the distances specified in table 3 if a category D pipeline.

83) If the MOP change results in a setback decrease or elimination, the licensee must notify all landowners and occupants along the entire pipeline right-of-way and within associated setbacks before submitting its application.

84) If the MOP change results in a sour gas EPZ change, the licensee must notify the residents within the existing and new EPZs before applying for a licence amendment.

3.8.2.4 Flow Reversal

85) If the flow reversal results in a setback increase, the licensee must complete the following actions before filing its application:

   a) Conduct personal consultation with confirmation of nonobjection with landowners and occupants along the entire pipeline right-of-way and within associated setbacks.

b) Provide notification to residents within the distances specified in table 3 if a category D pipeline.

86) If the flow reversal results in a setback decrease or elimination, the licensee must notify all landowners and occupants along the entire pipeline right-of-way and within associated setbacks before submitting its application.

87) If the flow reversal results in a sour gas EPZ change, the licensee must notify the residents within the existing and new EPZs before applying for a licence amendment.

3.8.2.5 Internal Protection

Participant involvement is not required when installing or removing a liner or applying a thin-film internal coating to an in situ pipeline.

3.8.2.6 Pipeline Discontinuance

Participant involvement is not required when discontinuing a pipeline.

3.8.2.7 Pipeline Abandonment

88) Before undertaking any activity to abandon a pipeline, the licensee must notify

a) the landowners and occupants along the entire pipeline right-of-way and within associated setbacks and

b) residents within the distances specified in table 3 if a category D pipeline.

3.8.2.8 Pipeline Removal

89) Before undertaking any activity to remove a pipeline, the licensee must notify

a) the landowners and occupants along the entire pipeline right-of-way and within associated setbacks and

b) residents within the distances specified in table 3 if a category D pipeline.

3.8.2.9 Pipeline Line Split

90) If the line split results in a setback increase, the licensee must complete the following actions before undertaking any line split activity:

a) Conduct personal consultation with confirmation of nonobjection with landowners and occupants along the entire pipeline right-of-way and within associated setbacks.

b) Provide notification to residents within the distances specified in table 3 if a category D pipeline.

91) If the line split results in a setback decrease or elimination, the licensee must notify all landowners and occupants along the entire pipeline right-of-way and within associated setbacks before undertaking any line split activity.

92) If the line split results in a sour gas EPZ change, the licensee must notify the residents within the existing and new EPZs before undertaking any line split activity.

3.8.2.10 Pipeline Resumption

93) If the resumption of a discontinued pipeline results in a setback increase, the licensee must complete the following actions before filing its application:

   a) Conduct personal consultation with confirmation of nonobjection with landowners and occupants along the entire pipeline right-of-way and within associated setbacks.

   b) Provide notification to residents within the distances specified in table 3 if a category D pipeline.

94) If the licensee is resuming an abandoned pipeline, it must complete the following actions before filing its application:

   a) Conduct personal consultation with confirmation of nonobjection with landowners and occupants along the entire pipeline right-of-way and within associated setbacks.

   b) Provide notification to residents within the distances specified in table 3 if a category D pipeline.

95) If the resumption of a pipeline results in a sour gas EPZ change, the licensee must notify the residents within the existing and new EPZs before applying for a licence amendment.

3.8.2.11 Pipeline Installation

96) The licensee must conduct all consultation and notification specified in table 3 and provide confirmation of nonobjection before submitting its application to amend its pipeline installation licence.

97) The licensee must consult area residents about noise during the design, construction, and operating phases of the pipeline installation.

3.8.3 Licence Expiry

98) Before initiating new construction, when a pipeline licence is nearing expiry, the licensee must conduct a new search for residents and landowners and determine if any new issues have arisen since granting the licence.

3.8.4 Licence Extension

99) To extend a pipeline licence expiry date, a licensee must update its participant involvement program before acting on the licence.

3.9 Additional Participant Involvement Requirements for Wells

3.9.1 Consultation and Notification Requirements for Wells

The consultation and notification requirements for wells by type are listed in table 4. The category type of a well is determined by the H_2S content, H_2S release rate, and proximity to the public.

100) The applicant must identify the correct category type for the proposed well project and perform all associated consultations and notifications.

101) For wells containing H_2S, the applicant must base the category type on the maximum wellhead, cumulative drilling, producing, or completion H_2S release rate. Applicants must review available production data and consider future production operations that may result in a reservoir originally not containing H_2S gas evolving to gas containing H_2S.

Stakeholder notification that has been completed as part of a *Directive 023* application for a new in situ oil sands project or an amendment to an existing project satisfies the participant involvement requirements for any related *Directive 056* application for the associated wells within the AER-approved in situ oil sands project area.

Table 4. Consultation and notification requirements by well type

Category	Name	Type	Description	Personal consultation and confirmation of nonobjection	Notification
B	Wells 0.00 mol/kmol H_2S	140 141 150	Single well Commercial or source water well Multiwell pad	• Landowners and occupants with regard to well-site location • Landowners and occupants with regard to well-site access • Residents within 0.2 km • Residents within 0.3 km, if single oil wells with 0.0 mol/kmol H_2S and continuous flaring	• Crown disposition holders • Local authorities • Freehold coal rights owner or coal rights lessee • Landowners within 0.1 km • Urban authorities within 1.5 km • Unlighted airports within 1.6 km • Lighted airports within 5 km
C	Wells >0.00 mol/kmol H_2S <0.01 m^3/s H_2S release rate Wells $\geq$0.01 m^3/s but	280 290 360	Single well Multiwell pad Single well	• Landowners and occupants with regard to well-site location • Landowners and occupants with regard to well-site access	• Crown disposition holders • Local authorities • Freehold coal rights owner or coal rights lessee • Urban authorities within 1.5 km

Category	Name	Type	Description	Personal consultation and confirmation of nonobjection	Notification
	<0.3 m^3/s H_2S release rate	370	Multiwell pad	• Landowners within 0.1 km with regard to setbacks • Residents within 0.2 km or the EPZ radius, whichever is greater	• Unlighted airports within 1.6 km • Lighted airports within 5 km
D	Wells ≥0.3 m^3/s but <2.0 m^3/s H_2S release rate	570	Single well	• Landowners and occupants with regard to well-site location • Landowners and occupants with regard to well-site access • Landowners within 0.5 km with regard to setbacks • Residents within 0.2 km or the EPZ radius, whichever is greater	• Crown disposition holders • Local authorities • Freehold coal rights owner or coal rights lessee • Urban authorities within 1.5 km • Unlighted airports within 1.6 km • Lighted airports within 5 km
E	Wells ≥2.0 m^3/s H_2S release rate	610	Single well	• Landowners and occupants with regard to well-site location • Landowners and occupants with regard to well-site access • Landowners within 1.5 km with regard to setbacks • Residents, local authorities, and urban authorities within the EPZ	• Crown disposition holders • Freehold coal rights owner or coal rights lessee • Unlighted airports within 1.6 km • Lighted airports within 5 km
	Wells ≥0.01 but <0.1 m^3/s release rate and within 0.5 km of urban centre	620	Proximity critical well	• Landowners and occupants with regard to well-site location • Landowners and occupants with regard to well-site access • Landowners within 0.1 km with regard to setbacks • Residents and local authorities within 0.2 km or the EPZ radius, whichever is greater • Urban authorities within 1.5 km	• Crown disposition holders • Freehold coal rights owner or coal rights lessee • Unlighted airports within 1.6 km • Lighted airports within 5 km

Category	Name	Type	Description	Personal consultation and confirmation of nonobjection	Notification
	Wells ≥0.1 but <0.3 m^3/s release rate and within 1.5 km of urban centre	621	Proximity critical well	• Landowners and occupants with regard to well-site location • Landowners and occupants with regard to well-site access • Landowners within 0.1 km with regard to setbacks • Residents and local authorities within 0.2 km or the EPZ radius, whichever is greater • Urban authorities within 1.5 km	• Crown disposition holders • Freehold coal rights owner or coal rights lessee • Unlighted airports within 1.6 km • Lighted airports within 5 km
	Wells ≥0.3 but <2.0 m^3/s release rate and well is within 5.0 km of urban centre	622	Proximity critical well	• Landowners and occupants with regard to well-site location • Landowners and occupants with regard to well-site access • Landowners within 0.5 km with regard to setbacks • Residents and local authorities within 0.2 km or the EPZ radius, whichever is greater • Urban authorities within 5.0 km	• Crown disposition holders • Freehold coal rights owner or coal rights lessee • Unlighted airports within 1.6 km • Lighted airports within 5 km

3.9.2 Licence Amendments

102) The applicant must be able to demonstrate there are no outstanding concerns or objections to file an application to amend a well licence or disclose that there are outstanding concerns or objections in its application.

3.9.3 Other Participant Involvement Requirements for Wells

103) The applicant must ensure that the participant involvement requirements are met for the radii given in table 4.

a) In cases where the completion or producing H_2S release rate is greater than the drilling release rate, the applicant must fulfil the personal consultation and notification requirements applicable to the highest rate.

b) The level designation of a well (table 10) must be based on the suspended/producing H_2S release rate. The applicant may choose to fulfil the participant involvement requirements with regard to setbacks using the setback radius for the suspended/producing release rate.

104) The applicant must meet the information requirements as part of personal consultation and notification for all well licence applications.

3.9.3.1 Airports

105) If the applicant proposes to drill a well within

a) 5 km of a lighted (registered or unregistered) airstrip or aerodrome or

b) 1.6 km of an unlighted (registered) airstrip or aerodrome,

before filing the well licence application, the applicant must advise Transport Canada using the appropriate Transport Canada drilling rig clearance form.

106) If the applicant proposes to drill a well within a 1.6 km radius of a private, unregistered, and unlighted airstrip or aerodrome, the applicant must notify the owner or operator before submitting the well licence application to the AER.

3.9.3.2 Coal Mines

107) If the applicant intends to drill through a bed or seam of coal, the applicant must notify in writing all Freehold coal rights owners and the lessees of Freehold or Crown coal rights (unless the applicant is also the holder of the coal rights). This notification must precede the filing of a well application with the AER.

The applicant is not required to notify the Crown regarding coal rights, whether or not the coal rights have been leased.

3.9.3.3 H_2S Release Rate Assessments

108) The applicant must conduct an H_2S release rate assessment for each category C, D, or E well to ensure public safety when developing projects containing H_2S gas. The H_2S release rate assessment determines the minimum EPZ for the proposed project and dictates the minimum radius for the applicant’s personal consultation and notification program.

109) If the producing or completion H_2S release rate is greater than the drilling release rate, the applicant must fulfil the personal consultation and notification requirements applicable to the higher rate.

3.9.4 Licence Expiry

110) Before initiating new construction, when a well licence is nearing expiry, the licensee must conduct a new search for residents and landowners and determine if any new issues have arisen since granting the licence.

3.9.5 Licence Extensions

The AER typically issues well licences with a one-year term.

111) To request a two-year term in its initial well licence, the applicant must update their public involvement notifications and review survey plan information prior to construction activities. If it is necessary to perform updates to its survey and participant involvement program, they must do so before starting construction.

112) To get an extended expiry date for an existing licence, the licensee must update its survey and participant involvement program before construction.

4 Application Audit Process

4.1 Overview

The AER provides the energy industry with requirements and expectations to assist the applicant or licensee both before submitting an application for energy development and throughout the life of a project. Applicants must meet the requirements outlined in *Directive 056*. Compliance with these requirements will be judged based on the representations that an applicant makes throughout the application process. The purpose of the audit process is to ensure industry's compliance and to identify areas for improvement.

The AER conducts audits both before a licence is issued and after the licence is issued. An audit may occur before issuing a licence

- if there are outstanding concerns or objections with an application;
- if there are existing environmental, safety, or compliance risks; or
- if there are issues concerning activities licensed under the *Geothermal Resource Development Act* or *Mineral Resource Development Act* that need to be evaluated.

Audits occurring after a licence is issued would determine whether and how the licensee is meeting the regulatory requirements.

Application audits are used to

- identify regulatory noncompliances,
- provide industry with feedback regarding compliant applications and areas for future improvement,
- measure the effectiveness of the application process and provide benchmarks for future improvements, and
- aid regulatory reform and the determination of requirements.

When conducting an audit, the AER relies upon the representations made and documents submitted by the applicant or licensee. The AER does not verify legal or beneficial title. The issuance of a licence or conducting of an AER audit is not to be relied upon by the licensee or third parties as a legal determination or confirmation of entitlement. Audits are conducted for AER internal purposes only.

4.2 Audit Selection

All applications are potential audit candidates. An application may be randomly selected by computer or judgementally selected by the AER based on factors such as category type, public risk, location, and recent applicant compliance history.

4.3 Audit Types

4.3.1 Full or Partial Audit Review

The AER may select an application for a postlicensing audit review and may undertake a full or partial audit of the supporting material.

1) When subject to a full audit, the licensee must submit all supporting documentation associated with the application. The licensee must provide additional information to support the audit upon request.

2) When subject to a partial audit, the licensee must submit any materials requested by the AER to demonstrate compliance with the portion of the application under review.

4.3.2 Immediate Audit

The AER normally allows 14 calendar days for a licensee to submit the requested audit documentation. However, in certain instances the AER may require an immediate audit (e.g., if participant involvement, mineral rights, or wellbore rights are in question).

3) If an immediate audit is conducted, the applicant or licensee must submit the requested audit material within the time set by the AER. This is usually within the same day, but the AER may require the information within hours.

4.3.3 Prelicensing Audit Reviews

4) The applicant must submit audit materials when requested.

5) If an application may proceed to a hearing, the AER may require that the applicant submit the entire audit package for review.

4.3.4 Link to AER Field Surveillance Inspections

Based on the findings of an application audit review, the AER may conduct a field inspection to confirm that the materials, operations, and commitments match those indicated in the application.

4.4 Audit Documentation

6) An applicant must retain copies of all applications and supporting data in the event of an audit. Refer to sections 4.7, 4.8, and 4.9 for a list of required audit documentation for facilities, pipelines, and wells.

7) The applicant must retain on file all records and audit documentation relating to an application for one year from the date of issue of the corresponding licence.

   The AER recommends that all records and audit documentation be kept on file for the life of the project, since exceptional circumstances may require that a review be conducted later in the life of the project.

8) The documentation must demonstrate that the supporting materials were developed and compiled during the project planning stage before filing the licence application.

9) The applicant must submit the required documentation to the AER within 14 calendar days of a request or as directed by the AER.

10) The AER must be able to determine from the audit documents that the applicant fulfilled all requirements to ensure regulatory compliance before filing the application.

4.5 Acquisitions

In cases of corporate property acquisitions or mergers, it is in the company's best interest to obtain all relevant application documentation when it acquires ownership of a facility, pipeline, or well.

11) A new owner is expected to assess all newly acquired properties to ensure that the property is operating with the correct *Directive 056* licence.

4.6 Compliance Records

Audit results are managed by the AER. A company wishing information on its compliance record pertaining to *Directive 056* applications must contact the AER.

4.7 Additional Audit Documentation Requirements for Facilities

The following sets out audit documentation requirements for facilities, additional documentation may be required. For licence amendment applications, the licensee may submit only that audit documentation applicable to the amendment activity.

4.7.1 Participant Involvement Requirements

4.7.1.1 Participant Involvement Map Requirements

12) The licensee must submit maps that illustrate

   a) the location of the facility,

   b) the location of all parties included in the participant involvement program (e.g., residents, similar facilities),

   c) the area of investigation used in the personal consultation and notification program,

d) the location of the nearest surface development,

e) the EPZ and location of residents within the calculated EPZ (if applicable), and

f) the area of investigation used in the industry notification program (if applicable).

4.7.1.2 Industry Notification Requirements

13) The licensee must submit a record of contact with other industry parties that includes

a) name, address, and telephone number of all parties contacted;

b) copies of all related correspondence received;

c) disclosure meeting minutes, including

i) date of meeting,

ii) meeting notice or invitation,

iii) invitation list, and

iv) names, addresses, and telephone numbers of all meeting participants; and

d) project information presented at meetings or otherwise distributed.

4.7.1.3 Personal Consultation and Notification Requirements

14) The applicant must submit a record of the personal consultation and notification program that was conducted.

15) The summary must include

a) name of each party (e.g., landowner, occupant, resident) included in the personal consultation and notification program,

b) legal land description for each party,

c) a description of each party's interest in the land (e.g., Crown disposition holder, landowner, resident, facility licensee),

d) date and type of contact conducted with each party (e.g., telephone conversation, registered mail, personal meeting),

e) date the required AER materials were distributed,

f) date the applicant's project-specific information package was distributed,

g) date the supplementary EnerFAQs were provided, and

h) date confirmation of nonobjection was obtained.

4.7.1.4 Confirmation of Nonobjection

16) The AER does not require that confirmation of nonobjection be in writing. Confirmation of nonobjection may consist of one of the following documents, depending on the nature of the proposed development:

   a) Freehold lease agreement (Freehold also includes federal lands and provincial Special Areas Board lands)

      The licensee must submit a copy of the agreement that confirms the parties involved, the date of agreement, and the location of land involved.

   b) Crown disposition (i.e., signed mineral surface lease, miscellaneous lease, or pipeline installation lease; executed area operating agreement (AOA) or temporary field authorization)

      In the case of an AOA, the licensee must submit copies of the following AOA documents:

      - the title page (including the details of the expiry date, company name, and area of operation)
      - the sign-off page (including when the agreement was executed)
      - geographical map and locations list

      For all other Crown dispositions, the licensee must submit a copy of the signed agreement that confirms the parties involved, the date of the agreement, and the location of the land involved.

   c) Signed document that identifies the details of the proposal (e.g., signatory page from the applicant's information package)

17) If confirmation of nonobjection is verbal, the licensee must document the name of the party providing verbal nonobjection and the date on which it was obtained.

4.7.1.5 Information Packages

18) The licensee must submit a copy of the project-specific information package that was distributed to the parties included in the participant involvement process.

It is not necessary to include a copy of the AER's documents in the audit submission. However, details of its distribution must be included.

4.7.1.6 Resolved Concerns and Objections

19) If concerns and objections were received and resolved during the course of the participant involvement program, the licensee must submit

    a) a record and explanation of any concerns and objections received and

    b) documentation confirming the resolution of any concerns and objections.

4.7.1.7 Sour Gas Planning and Proliferation

20) For cases where there are residents located within the EPZ of the facility, the applicant must submit

    a) the assessment of existing infrastructure required by section 8.3.2 and

    b) the updated expanded project-specific information package as described in section 8.3.2.

4.7.2 Emergency Response Planning

21) The licensee must keep a copy of the corporate emergency response plan (ERP) or, where required, an AER-approved ERP on file. It is not required for inclusion in the audit submission.

    The licensee must include in the audit submission a statement confirming that it has a corporate ERP or that an AER-approved ERP will be in place before starting operations.

For more information, see *Directive 071*.

4.7.3 Application Category

22) For category B facilities, the licensee must submit a gas analysis representative of the inlet stream. See table 1 for facility categories.

4.7.4 Design Criteria

23) For all facilities, the licensee must submit a written description of the proposed process scheme and a process flow diagram (PFD).

24) For custom treating facilities, the licensee must submit an inlet analysis to determine the percentage of oil, water, and solids.

25) For facilities with sources of nitrogen oxides (NO_x) and carbon dioxide (CO_2) emissions, the licensee must submit

    a) a breakdown and total of NO_x and CO_2 emissions for all sources in tonnes per day and kilograms per hour (kg/hr),

    b) manufacturer specifications to confirm NO_x and CO_2 emissions, and

c) if the total NO_x emissions are less than 16 kg/hr, diagrams to demonstrate that exhaust stack height requirements are met.

26) For facilities with continuous flaring, venting, or incineration, the licensee must submit

a) a list of all sources and

b) the results of the ground-level radiant heat intensity calculation.

4.7.5 Technical Information

4.7.5.1 Equipment Spacing Requirements

27) The licensee must submit a site-specific plot plan showing

a) equipment placement,

b) the distances between equipment, and

c) the distance from equipment to surface improvements, vegetation, water bodies, and roads (within 100 m of the lease boundary).

28) The licensee must state whether emergency shutdown valves are automated or manual control.

29) For heavy oil facilities, the licensee must submit a representative oil analysis.

4.7.5.2 Gas Conservation

30) For facilities with combined continuous flaring, venting, and incineration greater than 900 m^3/d, the licensee must submit the *Directive 060* economic evaluation and decision tree analysis. If it is not feasible to complete the conservation evaluation until the well test is completed, the licensee must submit an explanation of related reasons and a description of plans to complete the evaluations after initial production.

31) For gas processing plants with continuous flaring or incineration, the licensee must submit documentation indicating that the requirements in *Directive 060* have been met.

4.7.5.3 Noise Guidelines

32) For all facilities with noise-generating equipment, the licensee must submit a copy of the noise impact assessment prepared in accordance with *Directive 038*.

4.7.5.4 Storage Requirements

33) For facilities where products and materials will be stored on site, the licensee must submit a list of materials that will be stored and a description of the storage method (*Directive 055*), including details of

a) design and construction,

b) leak detection,

c) secondary containment,

d) weather protection, and

e) primary containment type and size.

4.7.5.5 Production Measurement Requirements

34) For all facilities, the licensee must submit a list and provide the location of each type of meter proposed for each measurement point.

35) For facilities with continuous flaring, venting, and incineration, the licensee must submit documentation to confirm how measurement and estimation procedures meet the requirements of *Directive 060*.

4.7.5.6 NO_x Emissions

36) For facilities where the NO_x emissions are less than 16 kg/hr, the licensee must submit documentation or a diagram demonstrating that the stack height for each source is at least 1.2 times the peak building height. If dispersion modelling was conducted, the licensee must submit the following:

a) documentation that confirms dispersion modelling was conducted in accordance with the *Air Quality Model Guideline*

b) the source parameters, locations, elevations, and NO_x emission rates for all sources

c) predicted maximum ground-level nitrogen dioxide (NO_2) concentrations

d) the name of the dispersion model used

e) a description of meteorological data used

f) a terrain map of the study area

37) For facilities with total NO_x emissions more than 16 kg/hr and all category C, D, and E gas plants that remove H_2S using regenerative sweetening processes, the licensee must submit the approval or registration number provided by the AER, if available. If the facility or amendment to the licence has not been registered or approved by the AER, the licensee must submit the following to demonstrate that it will meet the Alberta ambient air quality objectives (AAAQOs) before approval:

a) documentation that confirms dispersion modelling was conducted in accordance with the *Air Quality Model Guideline*

b) the source parameters, locations, elevations, and NO_x emission rates for all sources

c) predicted maximum ground-level NO_2 concentrations

d) the name of the dispersion model used

e) a description of meteorological data used

f) a terrain map of the study area

4.7.5.7 *Historical Resources Act* Clearance

38) Where applicable, the licensee must submit documentation showing that it received clearance from Alberta Culture before submitting the facility licence application.

4.7.5.8 AER Environmental Requirements

See section 8.6 if related to developments on the southern portion of the Eastern Slopes.

4.7.6 Gas Plants

The following are additional facility audit documentation requirements for gas plants, additional documentation may be required. For licence amendment applications, the licensee may submit only that audit documentation applicable to the amendment activity.

39) For new category C and D and all category E gas plants, the licensee must submit documentation regarding the alternatives to construction, including

a) evaluation of the technical and economic feasibility of using or modifying existing infrastructure,

b) an assessment of the social and economic effects of the alternatives, and

c) design parameters and available capacity of existing category C, D, and E gas plants that were considered.

40) For gas processing, straddle, fractionation, and sulphur recovery plants, the licensee must submit

a) a plant material balance for design conditions that matches the streams and equipment shown on the PFDs and includes

i) maximum H_2S content for both the inlet rate and the acid gas rate,

ii) design rates for the inlet and recovered products,

iii) maximum acid gas rate, and

iv) continuous sulphur emission rate and

b) an explanation of any differences between the applied-for rates and those contained in the plant material balance.

4.7.7 H_2S Information

The following are additional facility audit documentation requirements for H_2S information, additional documentation may be required. For licence amendment applications, the licensee may submit only that audit documentation applicable to the amendment activity.

4.7.7.1 Gas Treating and Processing Information

41) For facilities where an H_2S scavenger unit is proposed, the licensee must submit

a) a description of the H_2S scavenger system proposed and

b) the nature of the spent scavenger and its disposition.

42) For all facilities where the inlet H_2S content is more than 0.01 mol/kmol, the licensee must submit a wellhead or inlet gas analysis representative of the facility's inlet streams.

43) For facilities with continuous sulphur emissions, the licensee must submit a breakdown of all sources that contribute to the total value (e.g., flare, produced water tanks).

44) For facilities where the sulphur inlet is greater than 1 t/d, the licensee must submit an explanation of how the facility meets the current sulphur recovery guidelines.

4.7.7.2 Setback Requirements

45) The licensee must submit

a) the input parameters used to calculate the potential H_2S release volume of the highest level of pipeline associated with the facility (inlet or outlet streams),

b) a pipeline map showing emergency shutdown and check valve locations, and

c) the pipeline licence and line number for the highest level of pipeline associated with the facility.

4.7.7.3 Vapour Recovery

46) For facilities where the inlet H_2S is greater than 10 mol/kmol, the licensee must submit a description of the method proposed to control odours from storage tanks and other sources of vented gas, including the type of system.

47) For facilities where a product containing greater than 0.01 mol/kmol of H_2S will be transported, the licensee must submit documentation that confirms that a method to control off-lease odours during the transport of fluids containing H_2S gas is in place.

4.7.7.4 SO_2 Emissions and Stack Design

48) For facilities with continuous flaring/incineration where the inlet H_2S is less than 10 mol/kmol, the licensee must submit the heating value of the gas stream for the flare or incinerator.

49) For facilities where the inlet H_2S is greater than 10 mol/kmol, the licensee must submit the following

a) a schematic diagram or description of the flare or incinerator that must show a continuous pilot or automatic igniter, flame arrestor, and stack height

b) for incinerators, the residence time and exit temperature

c) documentation that demonstrates that the AAAQOs will be met for sulphur dioxide (SO_2) emissions from continuous sources and from nonroutine events.

The documentation must clearly show that dispersion modelling was conducted in accordance with the Alberta *Air Quality Model Guideline* and *Directive 060* and should include the following:

i) the source parameters, locations, elevations, and SO_2 emission rates for all sources

ii) predicted maximum ground-level SO_2 concentrations

iii) the name of the dispersion model used

iv) a description of meteorological data used

v) a terrain map of the study area

4.7.8 Compressors or Pumps

The following are additional facility audit documentation requirements for compressors/pumps, additional documentation may be required. For licence amendment applications, the licensee may submit only that audit documentation applicable to the amendment activity.

50) For facilities with compressors or pumps, the licensee must submit manufacturer specifications that confirm emission ratings, unit size, and driver type.

4.8 Additional Audit Documentation Requirements for Pipelines

The following sets out audit documentation requirements for pipelines, additional documentation may be required. For licence amendment applications, the applicant may submit only the audit documentation that was affected by the amendment activity.

4.8.1 Participant Involvement Requirements

4.8.1.1 Participant Involvement Map Requirements

51) The licensee must submit maps that illustrate

a) the location of the pipeline or installation,

b) the location of all parties included in the participant involvement process (e.g., residents, existing infrastructure),

c) the area of investigation used in the personal consultation and notification program,

d) the EPZ, and

e) the area of investigation used in the industry notification program.

4.8.1.2 Industry Notification Requirements

52) If industry notification occurs, the licensee must submit a record of contact with other industry parties that includes

a) name, address, and telephone number of all parties contacted;

b) copies of all related correspondence received;

c) disclosure meeting minutes that include

i) date of meeting,

ii) meeting notice or invitation,

iii) invitation list,

iv) names, addresses, and telephone numbers of all meeting participants; and

d) project information presented at meetings or otherwise distributed.

4.8.1.3 Personal Consultation and Notification Requirements

53) The applicant must submit a record of the personal consultation and notification program that was conducted. The summary must include

a) name of each party (e.g., landowner, occupant, and resident) included in the personal consultation and notification program,

b) legal land description for each party,

c) a description of each party's interest in the land (e.g., trapper, landowner, and resident),

d) date and type of contact conducted with each party (e.g., telephone conversation, registered mail, personal meeting),

e) date the required AER materials were distributed,

f) date the project-specific information package was distributed,

g) date the required EnerFAQs package was provided, and

h) date the confirmation of nonobjection was obtained.

4.8.1.4 Confirmation of Nonobjection

54) The AER does not require a confirmation of nonobjection to be in writing. Confirmation of nonobjection may consist of one of the following documents, depending on the nature of the proposed development:

a) a Freehold lease agreement (Freehold also includes federal lands and provincial Special Areas Board lands)

The licensee must submit a copy of the agreement, which must confirm the parties involved, date of agreement, and location of land involved.

b) a Crown disposition (i.e., a signed pipeline lease agreement, individual ownership plat, miscellaneous lease, or pipeline installation lease; an executed AOA or temporary field authorization)

In the case of an AOA, the licensee must submit copies of the following AOA documents:

- the title page (including the details of the expiry date, company name, and area of operation)
- the sign-off page (including when the agreement was executed)
- geographic map and locations list

For all other Crown dispositions, the licensee must submit a signed copy of the agreement that confirms the parties involved, the date of the agreement, and the location of the land involved.

c) a signed document that identifies the details of the proposal (e.g., signatory page from the applicant's information package)

55) If confirmation of nonobjection is verbal, the licensee must document the name of the party providing verbal nonobjection and the date on which verbal nonobjection was obtained.

4.8.1.5 Information Packages

56) The licensee must submit a copy of the project-specific information package that was distributed to the parties included in the participant involvement process.

4.8.1.6 Resolved Concerns and Objections

57) If concerns and objections were received and resolved during the course of the participant involvement process, the licensee must submit

a) a record and explanation of any concerns and objections received and

b) documentation confirming the resolution of any concerns and objections.

4.8.1.7 Sour Gas Planning and Proliferation

58) If there are residents located within the EPZ of a pipeline containing sour gas, the licensee must submit

a) the assessment of existing infrastructure required by section 8.3.2 and

b) the updated expanded project-specific information package as described in section 8.3.2.

4.8.2 Emergency Response Planning

59) The licensee must submit a statement to the AER confirming that it will have either a corporate ERP or an AER-approved ERP in place before starting operations.

The licensee must keep a copy of the corporate ERP or AER-approved ERP on file for review on request.

For more information, see *Directive 071*.

4.8.3 Transportation and Utility Corridors

60) If the pipeline is located within a transportation or utility corridor, the licensee must submit documentation confirming that the pipeline or installation has received ministerial consent from Alberta Infrastructure.

4.8.4 Environmental Information

See section 8.6 if related to developments on the southern portion of the Eastern Slopes.

4.8.5 Pipeline Technical Information

4.8.5.1 H_2S Content Requirements

61) If the licensed substance has a gas phase or is a liquid containing H_2S, the licensee must submit a representative gas analysis that demonstrates the H_2S transported in the pipeline is within the pipeline’s licensed parameters.

4.8.5.2 *CSA Z662*

62) The licensee must submit a statement confirming it has a Safety Loss Management System and integrity management program in place.

The licensee must provide any records and documents related to its Safety Loss Management System or integrity management program to the AER on request.

63) The licensee must submit mill certificates, product specification documentation, or other documentation to confirm the licensed line pipe meets the parameters of the licence. This documentation must indicate the line pipe outside diameter, wall thickness, material, type, grade, and any applicable sour service rating.

64) The licensee must submit specification documentation for the pipeline valves, flanges, and fittings to confirm the components meet the parameters of the licence. This documentation must indicate the components' nominal pressure rating and any applicable sour service rating.

65) If connecting an AER-licensed pipeline with another AER-licensed pipeline, the licensee must submit the following information regarding the other AER-licensed pipeline:

a) licence number

b) line number

c) substance

d) maximum H_2S content

e) MOP

66) If the pipeline connects with another AER-licensed pipeline and the difference between the licensed MOPs is greater than 5% of the lowest-licensed MOP, the licensee must submit documentation to demonstrate compliance with section 31 of the *Pipeline Rules*:

a) If the licensee proposes to use pressure control and overpressure protection, it must submit

i) a description of how the pressure control and overpressure protection meets *CSA Z662: Oil and gas pipeline systems* (latest edition) and

ii) a diagram of the equipment configuration with pressure control and overpressure protection devices clearly identified and set points indicated.

b) Where pressure control and overpressure protection are not required as permitted by section 31(4) of the *Pipeline Rules*, the licensee must submit an explanation of how the requirements of section 31(4) have been met.

67) Where *CSA Z662* specifies sectionalizing valve spacing requirements, the licensee must submit a description or map showing the valve locations and spacing.

4.8.5.3 Elevated-Temperature Pipelines

68) If the elevated-temperature pipeline requires registration by the Alberta Boilers Safety Association (ABSA), the licensee must submit documentation verifying that the pipeline design was registered with ABSA.

4.8.5.4 H_2S Release Volume and Level Designations

69) Where the licensed H_2S content of a sour natural gas or oil effluent pipeline is greater than 10 mol/kmol, the licensee must submit

a) the summary page from the pipeline's ERCBH2S model calculation (*Directive 071*),

b) representative tie-in schematics clearly showing the emergency shutdown and check valves,

c) a system map showing emergency shutdown and check valve locations, and

d) if applicable, the licence and line numbers of any other AER-licensed pipelines included in the pipeline's H_2S release volume calculation.

4.8.5.5 Sour Natural Gas Injection

70) If the licensee is injecting sour natural gas into a producing reservoir, it must submit an explanation of the impacts the scheme operation will have on the pipeline material and operating parameters.

4.8.5.6 Substance or H_2S Change

71) For a substance or H_2S change, the licensee must submit an engineering assessment demonstrating the pipeline is suitable for the intended use.

4.8.5.7 MOP Change

72) For an MOP increase, the licensee must submit an engineering assessment demonstrating the pipeline is suitable for the intended use and pressure test charts.

73) For an MOP decrease, the licensee must submit an explanation for the MOP decrease.

4.8.5.8 Internal Protection

74) The licensee must submit liner specification documentation and pressure test charts. If applicable, the documentation must indicate the liner type and grade.

4.8.5.9 Pipeline Discontinuance

75) For pipeline discontinuance, the licensee must submit the following:

a) the date (month, year) of the last active flow

b) the production source (i.e., a well or facility) and the licence number

c) the completion date (day, month, year) of the discontinuance activity

d) a report demonstrating that the discontinuance was conducted in accordance with the *Pipeline Rules*

e) a record of any medium left in the pipeline

f) a description of how the pipeline was managed while not in active flowing service

76) If the pipeline requires cathodic protection, the licensee must submit documentation confirming it will maintain cathodic protection on the discontinued pipeline.

4.8.5.10 Pipeline Abandonment

77) For pipeline abandonment, the licensee must submit the following:

a) the start date (day, month, year) of the pipeline abandonment activity

b) the completion date (day, month, year) of the pipeline abandonment activity

c) a report demonstrating that the abandonment was conducted in accordance with the *Pipeline Rules*

d) a record of any medium left in the pipeline

78) If the abandoned pipeline's previous status was "operating," the licensee must submit:

a) the date (month, year) of the last active flow

b) the production source (i.e., a well or facility) and the licence number

4.8.5.11 Pipeline Removal

79) For pipeline removal, the licensee must submit the following:

a) the start date (day, month, year) of the pipeline removal activity

b) the completion date (day, month, year) of the pipeline removal activity

c) a report demonstrating that the removal was conducted in accordance with the *Pipeline Rules*

4.8.5.12 Pipeline Resumption

80) For the resumption of pipeline operation, the licensee must submit an engineering assessment demonstrating the pipeline is suitable for the intended use.

81) The licensee must submit pressure test charts for any pressure test completed to verify pipeline integrity.

82) If the resumed pipeline was in a "discontinued" status before its resumption, the licensee must submit the documentation outlined in requirement 75 of section 4.8.5.9.

83) If the resumed pipeline or its risers required cathodic protection, the licensee must submit records for the last three years that confirm cathodic protection was active and effective.

4.8.6 Pipeline Installation Technical Information

84) For all pipeline installations, the licensee must submit

   a) a wellhead or inlet gas analysis representative of the inlet stream,

   b) a PFD that meets the requirements of section 6.8.1,

   c) a site-specific plot plan showing the placement of and distances between equipment, and

   d) a list of each type of meter proposed for each measurement point and their locations.

85) For compressor and pump stations, the licensee must also submit

   a) manufacturer specifications for the proposed unit that confirms emission ratings, unit size, and driver type;

   b) a noise impact assessment prepared in accordance with *Directive 038*;

   c) a breakdown and total of all sources of NO_x emissions in kilograms per hour; and

   d) if total NO_x emissions will be less than 16 kg/hr, documentation to demonstrate that exhaust stack height requirements are met in accordance with the *Environmental Protection and Enhancement Act* (*EPEA*).

86) For tank farms and oil loading and unloading terminals where products and materials will be stored on site, the licensee must also submit a list of materials that will be stored and a description of the storage methods, including details of

   a) design and construction,

   b) leak detection,

   c) secondary containment,

   d) weather protection, and

e) primary containment device and size.

87) For line heaters, the licensee must also submit documentation verifying that the line heater is designed to *Safety Codes Act* requirements.

4.9 Additional Audit Documentation Requirements for Wells

The following sets out audit documentation requirements for wells, additional documentation may be required. For licence amendment applications, the licensee may submit only that audit documentation applicable to the amendment activity.

4.9.1 Participant Involvement Requirements

4.9.1.1 Mapping Requirements

88) The licensee must submit maps that illustrate

a) the location of the well,

b) the location of all parties included in the participant involvement process (e.g., residents, hamlets, subdivision, public facilities),

c) the area of investigation used in the personal consultation and notification program, and

d) the EPZ (if applicable).

4.9.1.2 Personal Consultation and Notification Requirements

89) The licensee must submit a record of the personal consultation and notification program that was conducted.

90) The summary must include

a) name of each party (e.g., landowner, occupant, resident) included in the personal consultation and notification program,

b) legal land description for each party,

c) a description of each party's interest in the land (e.g., Crown disposition holder, landowner, resident, facility operator),

d) date and type of contact conducted with each party (e.g., telephone conversation, registered mail, personal meeting),

e) date AER documents were distributed if required,

f) date the project-specific information package was distributed,

g) date the required EnerFAQs package was provided, and

h) date confirmation of nonobjection was obtained if required.

4.9.1.3 Confirmation of Nonobjection

91) The AER does not require that confirmation of nonobjection be in writing; however, documentation must be submitted when available.

Confirmation of nonobjection may consist of one of the following documents, depending on the nature of the proposed development:

a) Freehold lease agreement (Freehold also includes federal lands and provincial Special Areas Board lands)
    i) The licensee must submit a copy of the agreement, which confirms the parties involved, the date of agreement, and the location of land involved.
b) Crown disposition (i.e., signed mineral surface lease or miscellaneous lease; executed AOA or temporary field authorization)
    i) In the case of an AOA, the licensee must submit copies of the following AOA documents:
        – the title page (including the details of the expiry date, company name and area of operation)
        – the sign-off page (including when the agreement was executed)
        – geographical map and locations list
    ii) For all other Crown dispositions, the licensee must submit a copy of the agreement, which confirms the parties involved, the execution of the agreement (signature), the date of the agreement, and the location of the land involved.
c) Signed document that identifies the details of the proposal (e.g., signatory page from the applicant's information package)

92) If confirmation of nonobjection is verbal, the licensee must document (log) the name of the party providing verbal nonobjection and the date on which verbal nonobjection was obtained.

4.9.1.4 Information Packages

93) The licensee must submit a copy of the project-specific information package that was distributed to the parties included in the participant involvement program.

It is not necessary to include a copy of the AER's documents in the audit submission; however, details of its distribution must be included.

4.9.1.5 Resolved Concerns and Objections

94) If concerns/objections were received and resolved during the course of the participant involvement program, the licensee must submit

a) a record and explanation of any concerns/objections received and

b) documentation confirming the resolution of any concerns/objections.

4.9.1.6 Sour Gas Planning and Proliferation

95) If there are residents located within the EPZ of the well, the applicant must submit

a) the assessment of existing infrastructure required by section 8.3.2 and

b) the updated expanded project-specific information package as described in section 8.3.2.

4.9.2 Emergency Response Planning

96) The licensee must keep a copy of the corporate ERP or, where required, the AER-approved ERP on file. It is not required for inclusion in the audit submission.

The licensee must include in the audit submission a statement confirming that it has a corporate ERP or that an AER-approved ERP will be in place before starting operations.

For more information, see *Directive 071*.

4.9.3 Well Purpose

97) For category B wells, the licensee must submit a representative gas analysis for each prospective horizon in the proposed well.

4.9.4 Minimum Casing Testing Requirements

98) The licensee must provide

a) confirmation that sufficient casing was set and cemented in the well for control purposes, and

b) confirmation that the casing has been pressure tested in accordance with the appropriate section of the minimum casing testing requirements (see section 7.7.5), and

c) confirmation and/or documentation that all applicable requirements in section 7.7.5 have been met for the specific type of well and drilling operation, or

d) documentation that a waiver was granted for the required inspection log.

4.9.5 Well Detail

99) The licensee must submit a survey plan. For CBM wells completed above the base of groundwater protection, the survey plan or an additional map must meet the requirements of *Directive 035*.

4.9.6 Surface Casing Requirements

100) The licensee must submit

a) a *Directive 008* "Surface Casing Depth Calculation" form, pressure survey, and pressure gradient documentation, including supporting information for the reduction type selected;

b) documentation confirming that the applicable criteria will be met for deep surface casing or surface casing exemptions, including any supporting information;

c) documentation showing the base of groundwater and a description of the method proposed to protect the groundwater; and

d) documentation that requirement 25 in section 7 has been met.

101) If a surface casing variance has been granted, the licensee must submit a copy of the approval issued by the AER that shows the presubmission application was reviewed and found to be acceptable.

4.9.7 Well Classification

102) If a drill cuttings variance has been granted before the well licence application is filed, the licensee must submit a copy of the approval issued by the AER.

4.9.8 Rights for All Intended Purposes

103) The licensee must submit

a) the mineral rights lease number for Crown minerals,

b) documentation that authorization has been obtained from the mineral rights lessee or owner for water injection or water source wells,

c) documentation that an appropriate agreement or authorization has been obtained for the evaluation of Crown minerals for the activity applied for, or

d) documentation that authorization has been obtained for Freehold minerals.

4.9.9 Rights for the Complete Drilling Spacing Unit

104) The licensee must submit

a) the mineral rights lease number for Crown minerals and

b) documentation evidencing the rights for Freehold minerals.

4.9.10 Water Body Setback Requirements

105) If the well centre is within 100 m of a water body, the licensee must submit documentation explaining the steps that were or will be taken to ensure that the water body is protected and that all AER requirements are met.

If there is potentially a water body on or near the proposed well's lease, the well application may be subject to further investigation. Subsequently, the applicant may need to demonstrate the efforts it has taken to determine the presence of any water body and to delineate the extent of any identified.

106) If a water body will be disturbed by the well activity, the applicant must submit to the AER the approval received under the *Water Act*.

4.9.11 Other Setback Requirements

107) If the proposed well is located within 100 m of a surface improvement, the licensee must submit documentation confirming that consent from the surface improvement owner was received before the well licence application was submitted.

108) If the proposed well is within 3 km of a working subsurface mine or within 400 m of an abandoned subsurface mine, the licensee must submit documentation confirming that the requirements of sections 6.140 to 6.190 of the *OGCR*, sections 36 to 39 of the *GRDR*, or sections 43 to 46 of the *BMR* will be met.

4.9.12 Environmental Requirements

109) The licensee must submit documentation outlining the steps that will be taken to ensure the protection of the environment and that all AER requirements are met.

See section 8.6 if related to developments on the southern portion of the Eastern Slopes.

4.9.13 CBM Wells

110) The following are additional well audit documentation requirements for wells completed above the base of groundwater protection. Submit documentation demonstrating that all the requirements as listed under "AER Environmental Requirements" above have been completed before applying. If water well testing was completed before applying, provide information confirming that those tests were completed in accordance with *Directive 035* requirements.

4.9.14 H_2S Release Rate

111) The licensee must submit a map showing the size and location of the search area used to obtain a minimum of five representative maximum H_2S concentrations and maximum AOF gas rates.

112) The licensee must submit an H_2S release rate documentation package (see section 7.7.15) that includes

a) a geological well prognosis, with a comprehensive geological discussion for all formations and zones;

b) geological mapping for all formations that it identifies as its primary and secondary zones that may contain H_2S gas;

c) an engineering discussion for each potentially productive zone that may contain H_2S gas; and

d) tabulated data that provide the results of H_2S concentration and AOF rate reviews.

113) If a presubmission H_2S release rate assessment was submitted, the licensee must submit a copy of the letter issued by the AER that indicates that the presubmission application was reviewed and that sets out the release rate values considered acceptable to the AER.

4.9.15 Intermediate Casing

114) The licensee must submit the depth to which the intermediate casing will be set.

115) If an intermediate casing waiver has been granted, the licensee must submit a copy of the approval issued by the AER that shows that the prelicensing application was reviewed and found to be acceptable.

4.9.16 Drilling Critical Wells

116) The applicant must submit a complete and detailed drilling plan based on the requirements in *Directive 036* and *IRP Volume 1: Critical Sour Drilling*. The drilling plan must include a detailed table of contents.

117) The applicant must submit a copy of any applicable variance approvals obtained from the AER before filing an application.

5 Facility Licence Applications

5.1 Overview

An applicant must apply for a licence to construct or operate a facility unless exempt under section 5.4.1.

An application must also be made to amend a licence in certain circumstances. It is important that licensees and operators be aware of the operational and equipment scenarios requiring a facility licence and when a modification to an existing facility warrants a licence amendment application.

If the applicant cannot meet a technical requirement, chooses to apply for a regulatory relaxation, cannot meet all participant involvement requirements, outstanding concerns or objections exist, or proposes to implement new technology, the applicant must disclose the situation in its application. If there are outstanding concerns or objections to an exempt activity, the activity is no longer exempt from licensing, and an application disclosing the situation must be submitted.

1) Facilities associated with an in situ crude bitumen scheme approval require licensing under *Directive 056*. This facility application may be submitted concurrently with the scheme application (see *Directive 023: Oil Sands Project Applications*). In the event that approval under *Directive 056* is issued before a decision on the associated *Directive 023* application, construction and site preparation must not commence until all necessary approvals are obtained.

2) The applicant must file an application for a multiwell battery or satellite when the surface equipment on site meets the criteria for licensing and when

   a) a single well has segregated production from more than one zone (i.e., not commingled in the wellbore) producing to the battery or satellite;

   b) a new inlet is added to an existing single-well battery or satellite that includes, at a minimum, measurement for the production from a second well; or

   c) multiple single-well batteries or satellites are operating within one surface lease.

If the applicant has both oil and gas and brine-hosted mineral production from separate wells or segregated zones within the same well at the same surface location, the surface facility should be licensed for the most significant operation at the site.

3) If the processing of solution gas or nonassociated gas is implemented at an existing licensed oil battery, the gas processing equipment must be licensed as a separate facility.

5.2 Licence Expiry

New facility licences expire one year from the date of issue if the licence has not been acted on (i.e., construction has not started). The AER will cancel the expired licence from the active records. It is the licensee's responsibility to ensure that the facility licence is still valid and has not expired before starting any activity associated with the licence. Companies are expected to provide a courtesy notification to the AER using the designated information submission system advising that construction has started on the licensed facility.

4) If an applicant intends to proceed with a project for which a licence has expired, it must cancel that previous licence and also fulfil all applicable regulatory requirements, including all participant involvement requirements in section 3, before filing a new application.

5) If an applicant does not intend to proceed with the licence, it must notify the AER and request that the licence be cancelled.

Due to the complexity of some facility developments, a licensee may be unable to act on a permanent facility licence or complete operations at a temporary facility before the licence expires. Licensees can file a licence amendment application to extend the expiry date of a permanent or temporary facility licence.

6) Before starting new construction when a licence is nearing expiry, the applicant must meet the participant involvement requirements in section 3.

7) To apply to extend the expiry date of a facility licence or a temporary facility licence, the applicant must meet the participant involvement requirements in section 3.

A facility licence that has been acted on cannot be cancelled. Licensees that do not intend to act on a facility licence may request that the licence be cancelled by contacting the AER.

5.2.1 Licence Extensions

The AER typically issues facility licences with a one-year term. An applicant may make a request to extend the expiry date of an applied-for licence at the time of application. Requests for extensions will be considered on a case-by-case basis.

The AER may extend the expiry date of a facility licence that has already been issued upon request of the licensee.

8) To get an extended expiry date for an applied-for licence, the applicant must meet the participant involvement requirements in section 3 before it acts on the licence.

9) To get an extended expiry date for an existing licence, the licensee must meet the participant involvement requirements in section 3 before it acts on the licence.

5.3 Category Type and Consultation and Notification Requirements

The category type and the consultation and notification requirements for facilities are listed in table 1. The category type of facility depends on the H_2S and sulphur content of the inlet gas stream. Use category type B091 if applying for a geothermal facility only even if the H_2S and sulphur content of the inlet gas stream is >0.01 mol/kmol. Some values are electronically verified and entered in the application with the actual values provided in a PDF document (labelled "Miscellaneous") attached to the facility application. Applicants use the actual H_2S and sulphur content of the inlet gas stream to determine the appropriate consultation and notification requirements and conduct a program appropriate to these values. Applicants should review section 4.2 of *Directive 089* for other application requirements.

10) The highest H_2S content must be based either on pipelines entering the facility or on any well associated with the raw gas inlet.

5.4 Exemptions

11) Even though no application is required under this directive for the exempt activities and facilities in sections 5.4.1 and 5.4.3, a company must meet all applicable regulatory requirements, including the participant involvement requirements in section 3.

12) To proceed with a proposal where a concern or objection has been received and remains unresolved, the company must submit an application.

5.4.1 Single-Well Facility Sites

5.4.1.1 Single-Well Hydrocarbon Facility Sites

An application is not required under *Directive 056* if the facility is a single-well hydrocarbon site for oil, bitumen, or gas where the H_2S content is *less than* 0.01 mol/kmol and

- total on-site wattage for compressors is less than 75 kilowatts (kW),
- there is no gas processing, and
- there is no injection or disposal component.

An application is not required under *Directive 056* if the facility is a single-well *gas* site where the H_2S content is *greater than* 0.01 mol/kmol and

- there are no liquid hydrocarbon or produced water storage tanks,
- there is no gas compression,
- there is no gas processing, and
- there is no injection or disposal component.

5.4.1.2 Single-Well Geothermal or Brine-Hosted Mineral Facility Sites

Applications are required for single-well geothermal facility sites and single-well brine-hosted mineral sites using the established category types listed in table 1.

5.4.2 Other Facilities

5.4.2.1 Installation of On-site Power Generating Equipment

On-site power generation is managed and approved by the Alberta Utilities Commission (AUC). Although the facility licence should include emissions and noise impacts from all on-site sources, power generation equipment is not licensed under *Directive 056*. For more information, contact the AUC.

5.4.2.2 Oil Sands Processing Plants

Oil sands scheme approvals for in situ operations continue to be issued under *Directive 023*. Licences for surface facilities associated with oil sands mine approvals are not issued under *Directive 056*.

Surface facilities associated with approved in situ schemes require a *Directive 056* facility licence.

5.4.2.3 Oilfield Waste Management Facilities

Oilfield waste management facilities are not licensed under *Directive 056*. See the AER website for information on approvals to construct and operate new facilities, modify existing facilities, and notifications of minor modifications to existing facilities.

If a facility currently licensed under *Directive 056* becomes a waste management facility, a *Directive 058* approval is required and the previously issued *Directive 056* licence will be cancelled. Operators are reminded that the receipt of oilfield waste from outside of a facility's production system for consolidation and transfer or for on-site storage or management is not permitted unless the facility is approved as an oilfield waste management facility.

5.4.3 Exempt Activities

Applications are not required for the following activities under *Directive 056* provided that the activity does not change the category type of the facility:

- temporary compressors in continuous use for less than 21 consecutive days as an alternative to flaring for such operations as the conservation of initial well test gas or plant turnaround, provided that landowner nonobjection has been obtained and regulatory requirements are met (see *Directive 060*)
- replacing measurement and separation equipment

- installation of downhole (subsurface) equipment
- adding well production to an existing licensed multiwell facility
- replacing a compressor or injection or disposal pump with the same type and size or a smaller one, such that total emissions do not increase
- adding separators, dehydrators, pressurized bullets, process pumps, or group or test vessels to an existing licensed facility
- adding a line heater to an existing licensed facility
- adding a vapour recovery unit to an existing licensed category C, D, or E facility
- adding one compressor less than 75 kW to an existing licensed facility, provided that the landowner has been notified and has no concerns and that the facility will meet nitrogen oxides (NO_x) and noise requirements at the nearest residence (does not apply to acid gas injection compressors, regardless of size; compressors less than 75 kW that were installed previously as an exempt activity should be indicated the next time an amendment application for the facility is required)
- adding storage tanks to an existing licensed facility (all *Directive 055* requirements must be met, including secondary containment)

5.5 Licence Amendments

Only facilities that have an existing AER facility licence number can be amended.

13) When filing a licence amendment application, the applicant must retain the original facility type (e.g., gas battery, oil battery) unless

    a) additional equipment proposed for installation will cause the gas facility to become a gas processing plant (e.g., the addition of a refrigeration skid will change an existing compressor station to a gas processing plant) or

    b) equipment proposed for removal will cause the facility type to change (e.g., the removal of the refrigeration process will change an existing gas processing plant to a gas battery).

14) Applicants must file licence amendment applications when the proposed activity will increase emissions, risk, or impacts on the public.

New facility licence applications for categories C, D, and E gas processing plants and licence amendment applications for category E gas processing plants require that all supporting audit documentation be submitted with the application. Licence amendment applications for categories C and D gas processing plants may be submitted without supporting audit documentation if there are no participant involvement or technical issues.

5.6 Technical Requirements

5.6.1 Emergency Response Planning

The EPZ for a category C, D, or E facility is based on the largest EPZ of any pipeline entering or leaving the facility. Applicants are cautioned that it is a violation of privacy legislation to disclose in the public portion of a facility, pipeline, or well licence application any personal information that was obtained for emergency response planning purposes. Such information must be provided to the AER in confidence (see *Directive 071*).

5.6.2 Liability Management

Oil, gas, and in situ development must follow the liability management framework requirements in *Directive 088*. Refer to *Directive 011* for estimated liability information, including information regarding the need for certain licences to complete site-specific liability assessments in accordance with *Directive 001* before applying for a new licence or amending the licence type.

Applications for geothermal and brine-hosted mineral resource development must follow the liability requirements in *Directive 089* and *Directive 090*, respectively.

5.6.3 Proliferation

As the proponent of a new facility or pipeline, the applicant has already determined that the proposed project will meet its business needs. The AER, as the approving authority, is required to evaluate the need for the proposed project and encourages all applicants to consider the reuse of existing or reclaimed sites. The AER's sour gas proliferation requirements are set out in *ID 2001-03: Sulphur Recovery Guidelines for the Province of Alberta* and are summarized below.

15) Before filing an application for a new category C, D, or E gas processing plant, the applicant must

    a) evaluate all existing sour gas plants and pipelines that offer viable alternatives within a 15 km radius of the proposed new sour gas plant, regardless of ownership or interest:

        i) the applicant must evaluate the feasibility of upgrading an existing facility and of forging commercial partnerships with existing licensees;

        ii) the applicant must obtain an accurate assessment of the capabilities of existing sour gas plants, including design parameters (e.g., operating pressures and limitations on H_2S content) and capacity available; and

        iii) the applicant must demonstrate that feasibility of modifying the facilities was evaluated with the licensee if existing plants are not designed to handle the applicant's gas or if there are capacity limitations—high processing fees, in and of themselves, may not be considered sufficient grounds for rejecting the option to use an existing facility;

b) assess the area's future production potential to ensure that the proposed facility is designed to meet the regional long-term processing needs; and

c) contact other sour gas reserve owners within 5 km of a proposed new sour gas plant with a view to inviting these well licensees to participate in the new facility in some manner.

16) The applicant must include information on its assessment as part of the application audit package submitted to the AER.

17) The applicant of a new category C, D, or E gas processing plant must formally contact licensees of existing facilities for required information and be able to document related responses.

The AER expects the parties to share information in a timely manner. If the applicant is unable to obtain the information necessary to conduct an assessment, it should contact the AER.

18) To avoid the unnecessary development of new category C and D facilities, the applicant is expected to investigate the feasibility of using existing facilities and pipelines before submitting an application to the AER.

5.6.4 Facility Design Criteria

19) The inlet and recovered product rates must represent the total design rates associated with all on-site equipment at the surface location based on a daily maximum.

20) For facility licence amendments, the inlet and recovered product rates for the facility must represent the total on-site design rate, not only the design rates of the additional equipment.

For facilities with a sulphur inlet greater than 1 t/d, the raw gas inlet rate and sulphur inlet rate represent the maximum operating limits for the facility. These rates are monitored by the AER.

Heavy oil/oil sands batteries and satellites are also subject to the regulatory requirements detailed in *ID 91-03: Heavy Oil/Oil Sands Operations* and *IRP Volume 3: In Situ Heavy Oil Operations*.

21) The applicant must ensure that an oil analysis is available to demonstrate that the gravity of the inlet stream matches the category applied for and that the facility will meet the requirements of these documents for heavy oil facilities.

5.6.5 Sulphur Recovery

[*ID 2001-03*](): *Sulphur Recovery Guidelines for the Province of Alberta* sets out the basis for AER's requirements around sulphur recovery and emissions reduction from

- category D and E gas processing plants and
- other types of upstream industry operations licensed under *Directive 056* where continuous flaring or incineration of gas containing H_2S occurs (e.g., production batteries, dehydration facilities, and compressor stations where the bulk gas stream is not sweetened).

22) The applicant must meet the requirements of *ID 2001-03*.

    If the applicant believes a variance to the minimum recovery levels of *ID 2001-03* is warranted, the applicant may disclose the request for variance in its application.

23) When designing new category D and E gas processing plants, the applicant must

    a) comply with the calendar quarter-year sulphur recovery of *ID 2001-03*, and

    b) determine the sulphur recovery based on mass (tonnes sulphur equivalent) using the following formula:

    $$sulphur\ recovery = \frac{sulphur\ production}{(sulphur\ production + sulphur\ emissions)}$$

    where *sulphur production* is the tonnes of sulphur product and tonnes sulphur equivalent contained in injected sour gas or acid gas streams and *sulphur emissions* is the tonnes sulphur equivalent contained in flared sour and acid gas streams and in the sulphur recovery unit tail gas or incinerator stack emissions.

24) For other upstream industry facilities where sulphur recovery requirements apply, the applicant must

    a) comply with the calendar quarter-year sulphur recovery of *ID 2001-03*, and

    b) determine the sulphur recovery requirements based on the sulphur content of flared or incinerated gas streams (not on the sulphur inlet of the facility), in addition to the sulphur recovery unit tail gas incinerator stack emissions.

25) If an applicant is filing a licence amendment application to modify a grandfathered gas plant, the applicant must meet the special provisions set out in *ID 2001-03*.

26) For facilities where subsurface injection is the method of acid gas disposal, a separate AER approval is required for the injection scheme in accordance with the requirements of *Directive 065: Resources Applications for Conventional Oil and Gas Reservoirs*. Additional information may be obtained from the AER.

5.6.6 Process Flow Diagrams

27) The applicant must attach a PFD for each facility application.

a) The PFD must identify all existing and proposed equipment at the facility.

i) For licence amendments, the applicant must identify the new equipment proposed for installation on a full-site PFD; a partial PFD is not acceptable.

– New equipment must be identified in the legend and annotated on the diagram.

– Equipment designated for removal by the application must also be clearly identified.

b) The applicant must clearly identify the following on the PFD:

i) process equipment

ii) measurement points

iii) storage vessels and tanks (including pop tanks)

iv) sources of all inlets, receipts, and deliveries, including all fuel lines, flare lines, and vent points

v) safety equipment (i.e., location of emergency shutdown device block valves and depressure points)

c) Where the applied-for energy resource facilities (i.e., oil, gas, geothermal, or minerals dissolved in brine) are collocated, the applicant must provide a table listing the equipment for each facility and either provide a PFD for each facility or a single PFD that clearly differentiates the processes for each facility.

Diagrams are acceptable, providing that they represent the actual operations of the facility accurately and contain the correct location and applicant name.

Piping and instrumentation diagrams should be submitted if available at the time of application.

5.6.7 Total Continuous Emissions

28) The applicant must include the volume of gas from all sources on site that is disposed of by burning in a flare or incinerator. This does not include fuel gas used for header purge, pilot fuel, make-up gas to achieve effective combustion, sulphur recovery unit tail gas, or volumes attributed to emergency conditions or maintenance operations.

Applicants proposing to flare or incinerate gas must comply with the requirements of *Directive 060*.

29) The applicant must include the volume of gas vented from all sources on site, including any volumes of CO_2 associated with a sweetening process.

    Applicants proposing to vent gas must comply with *Directive 060* and section 8.080 of the *OGCR*.

30) The applicant must evaluate the conservation of continuous flared, incinerated, and vented volumes in accordance with *Directive 060*.

If NO_x emissions are present, it is the applicant's responsibility to ensure that the facility meets the AAAQOs for NO_2. It is possible that facilities exempt from registration under *EPEA* could exceed the AAAQOs. It is in the company's best interest to conduct modelling to ensure that its facility will meet the AAAQOs. In order to demonstrate that the facility meets the AAAQOs, the AER may require that the applicant provide NO_x modelling.

31) In designing its compression needs, the applicant must design the facility to meet the requirements set out by AEPA's *Code of Practice for Compressor and Pumping Stations and Sweet Gas Processing Plants*.

32) The applicant must register all compressor stations, pumping stations, and category B gas processing facilities with the AER before commencing operation if the total NO_x emissions are greater than 16 kg/hr.

33) New and additional natural gas-driven reciprocating engines greater than 600 kW at full load must not emit more than 6 grams of NO_x per kilowatt-hour (g/kWh).

34) The applicant must meet the following requirements when NO_x emissions are present at facilities that require registration or approval with the AER:

    a) Dispersion modelling must be conducted in accordance with AEPA's *Air Quality Model Guideline*.

    b) Based on dispersion modelling, predicted NO_2 concentrations must meet the AAAQOs, using guidance from the *Air Quality Model Guideline*.

    c) Standby equipment used only for emergency purposes may be excluded from dispersion modelling.

    d) The engine exhaust stack height must be set in accordance with the direction given in AEPA's *Code of Practice for Compressor and Pumping Stations and Sweet Gas Processing Plants*.

    e) NO_x emissions from steam generating units, heaters, and boilers may be excluded from dispersion modelling if their combined contribution is less than 3% of the total NO_x emissions.

5.6.8 Compressor and Pump Additions

Temporary compressors in use for less than 21 consecutive days to test new gas well production as an alternative to flaring do not require a licence under *Directive 056*, provided that

- there is no other compressor on site,
- the licensee or operator has met the participant involvement requirements in section 3, and
- the compressor will meet all regulatory requirements, including noise and NO_x requirements.

35) If there are any unresolved concerns or objections received, the applicant must disclose this in its application.

36) The use of temporary compressors is limited to a one-time-per-site occurrence. For further information on temporary compressors, see *Directive 060*. Licensees and operators must notify the AER before operation.

37) Licensees are not required to submit a licence amendment application for the purpose of adding one compressor or pump less than 75 kW to an existing licensed facility. In these instances, the licensee must

    a) provide the landowner with a written description of the project,

    b) ensure that the participant involvement requirements in section 3 are met, and

    c) ensure that the facility will meet the NO_x and noise requirements.

This exemption does not apply to acid gas injection compressors, regardless of size, and does not apply to the use of temporary compression greater that 75 kW for any period of time for the purpose of determining permanent compression requirements.

Compressors less than 75 kW that were installed previously as an exempt activity should be indicated the next time an amendment application for the facility is required.

All compressors at a site are to be licensed as part of the facility unless the equipment is used to provide instrument air.

Applications are required for all compressor installations at new facilities regardless of the kW rating if the H_2S content of the inlet gas is greater than 0.01 mol/kmol (not including temporary compressors used for new gas well testing less than 21 consecutive days).

Applications are not required for the installation of process pumps that are not related to the injection or disposal of water or for enhanced oil recovery (EOR) purposes (e.g., glycol or chemical injection pumps, oil or water transfer pumps, recycle pumps, injection booster pumps).

38) The applicant must apply for the installation of pumps associated with the injection or disposal component of a facility, regardless of pump size.

a) The applicant must amend the existing facility licence, retaining the original category type, to add an injection or disposal component to an existing licensed facility.

b) Third-party injection or disposal facilities must be licensed as waste disposal facilities under *Directive 058*.

For licensing of compressors or pump stations on transmission pipelines (sales products), see section 6.

Facility licences issued under *Directive 056* do not include the installation of generators whose purpose is to generate power as part of a solution gas conservation process. In such cases, *Directive 056* remains the licensing point for the battery portion of the operations, while the generators require licensing with the AUC.

5.6.9 Setback Requirements

There are specific setback distances between category C, D, and E facilities and permanent dwellings, unrestricted country developments, urban centres, or public facilities.

39) The applicant must meet the applicable setback requirements in table 5 based on the calculated H_2S release volume for pipelines associated with the proposed facility.

40) The applicant must consider the level designation of inlet and outlet pipelines and use the highest level designation to determine the facility setback requirement.

41) Release volumes from on-site equipment must not be totalled to determine the setback requirements of the facility.

42) The applicant must meet the participant involvement requirements in section 3.

Table 5. Setback requirements for category C, D, or E facilities with pipelines containing H_2S

Level	H_2S release volume (m^3)	Minimum distance
1	<300	Lease boundary
2	$\geq$300 to <2000	0.1 km to individual permanent dwellings and unrestricted country developments 0.5 km to urban centres or public facilities
3	$\geq$2000 to <6000	0.1 km to individual permanent dwellings up to 8 dwellings per quarter section 0.5 km to unrestricted country developments 1.5 km to urban centres or public facilities
4	$\geq$6000	As specified by the AER, but not less than those given in level 3

5.6.10 Plot Plans and Equipment and Off-Lease Spacing Requirements

43) A plot plan must be submitted with each facility application that clearly indicates the on-lease location of all the equipment (except for valves) and reflects all surface improvements, water bodies, and vegetation for a minimum of 100 m past the edge of the lease to demonstrate that all off-lease spacing requirements have been met (e.g., distance to a residence, water bodies, forestation, or road allowance).

The following is an abbreviated list of the spacing requirements. Equipment and off-lease spacing requirements are set out in full in Part 8 of the *OGCR*, Part 3 of the *GRDR,* Part 3 of the *BMR*, and *ID 91-03: Heavy Oil/Oil Sands Operations and Clarification*.

44) Unless the AER permits otherwise, the applicant must meet the AER's spacing requirements. If the applicant cannot meet the AER's spacing requirements, the applicant must disclose this in its application.

   a) Tanks containing fluids other than fresh water must be located so that the distance from the outer perimeter of the dike to any surface improvement (other than a public roadway) is not less than 60 m (*OGCR* 8.030(4), *GRDR* 47(4), and *BMR* 54(4)).

   b) Facility equipment must maintain a minimum distance of 100 m from a water body (*OGCR* 8.060, *GRDR* 53, and *BMR* 60).

   c) Flare pits and flare line ends must not be located closer than 100 m to a surface improvement, except a surveyed roadway (*OGCR* 8.080(3)). Flares and incinerators must be located at least 40 m from a surveyed roadway or road allowance with open public access (*Directive 060*).

   d) A flare pit or the open end of a flare line must not be located or remain within 50 m of a well or oil storage tank (*OGCR* 8.080(5)).

   e) A flare pit or open end of a flare line must not be located or remain within 25 m of any oil or gas processing equipment (*OGCR* 8.080(5)).

   f) Oil storage tanks must be at least 50 m from a well (*OGCR* 8.090(3), *GRDR* 67(3), and *BMR* 74(3)).

   g) Flame-type equipment must not be placed or operated within 25 m of a well, oil storage tank, or other source of ignitable vapour (*OGCR* 8.090(4), *GRDR* 67(4), and *BMR* 74(4)).

   h) Flame-type equipment must not be placed or operated within 25 m of any process vessels unless, where such is applicable, the flame-type equipment is fitted with an adequate flame arrester (*OGCR* 8.090(5), *GRDR* 67(5), and *BMR* 74(5)).

   i) The exhaust pipe from an internal combustion engine, located less than 25 m from a well, process vessel, oil storage tank, or other source of ignitable vapour must be located at least 6 m from the vertical centre of the well and directed away from the well (*OGCR* 8.090(9), *GRDR* 67(9), and *BMR* 74(9)).

j) The flare, incinerator, and enclosed burner spacing must comply with the requirements defined in the current *Forest and Prairie Protection Regulation*.

k) Compressors (electrically or engine driven) that are permanent and housed in a building must be located 25 m or more from wells.

Compressors are considered permanent when placed on pilings or a defined foundation and connected to the facility with rigid piping.

l) Nonpermanent compressors (on wheels or skid mounted) must be spaced such that the air intakes and exhaust must be no closer than 6 m to a well.

Compressors are considered nonpermanent when they can be quickly disconnected and moved from where they are placed and there is no associated foundation constructed.

m) Nonpermanent electrically driven compressors must comply with the current edition of *Code for Electrical Installations at Oil and Gas Facilities*, Safety Codes Council (Alberta).

Location of tanks and flare systems relative to public roadways are not specified in the *OGCR*, *GRDR*, and *BMR*. When planning facilities within 100 m of a municipal road, applicants should discuss the placement of tanks with the local authority. Additionally, for facilities planned within 300 m of a major (numbered) highway or within 800 m of an intersection of two major highways, applicants should contact Alberta Transportation for permit requirements.

5.6.11 Vapour Recovery and Odour Control

Trucks are viewed as part of the facility operation when loading, unloading, and transporting fluid containing H_2S gas.

45) For facilities where the maximum H_2S content of the inlet gas is greater than 0.01 mol/kmol, the applicant must ensure that there are no off-lease odours from trucking operations and the transfer of fluids containing H_2S gas by implementing a method to control off-lease odours, such as the use of a pressurized or sealed vessel.

46) For facilities where the maximum H_2S content of the inlet or vented gas is greater than 10 mol/kmol, the applicant must include a suitable method to recover and handle vapours from stock tanks or burn the vapours. When designing the facility, the applicant must ensure that stock tank vapours are not discharged to the atmosphere without proper combustion of the sulphur compounds.

47) If a vapour recovery unit is required because the composition of the inlet stream has changed and the gas stream now contains more than 10 mol/kmol of H_2S, the licensee must submit an application to change the category type of the facility to category C, D, or E.

Applicants are not required to file a licence amendment application for the purpose of installing a vapour recovery unit at an existing category C, D, or E facility, provided that the participant involvement requirements in section 3 have been met, there are no landowner concerns, and the facility meets the NO_x requirements and the noise requirements at the nearest residence.

48) When the maximum inlet H_2S content of the gas is greater than 10 mol/kmol and a vapour recovery unit will not be installed, the applicant must provide an explanation of its proposed method of vapour control in its application.

5.6.12 Noise Requirements

All facilities under the AER's jurisdiction must meet the requirements of *Directive 038: Noise Control*.

A noise impact assessment (NIA) ensures that the applicant considers possible noise impacts before constructing or operating a facility. The NIA predicts the expected design sound level from the facility at the nearest or most affected residence.

49) An NIA must be completed before submitting a facility application for any new permanent facility or for modifications to existing permanent facilities if there is a reasonable expectation of a continuous or intermittent noise source. (For the purpose of an NIA, a permanent facility is a facility in operation for more than two months.)

50) If the NIA indicates that the permissible sound level will be exceeded, the applicant must consider further mitigative measures. Where mitigative measures are not practical the applicant must explain why in its application.

51) The AER expects the applicant to use a reasonable technical basis for the values presented in the NIA, such as computer modelling, field measurements of similar equipment, accepted acoustical engineering examples from literature, and calculations.

52) If the applicant is using manufacturer's specifications, the sound level ratings must represent free or far-field conditions. Sound level ratings at 1 m are not acceptable for inverse square law calculations.

5.6.13 Alberta Environment and Protected Areas

All applicants should be aware that additional licences or approvals might be required from AEPA.

If a facility requires both an AER and an AEPA licence or approval, and there are unresolved concerns or objections that were received during the participant involvement program, the applicant is encouraged to advertise both applications together through a joint notice. The applicant must meet the participant involvement requirements in section 3.

53) Flare stacks must be designed to meet the AAAQOs and be in accordance with methods outlined in *Directive 060* and AEPA's *Air Quality Model Guideline*.

54) Based on dispersion modelling, the ground-level concentration of SO_2 must meet the AAAQOs, based on guidance from the *Air Quality Model Guideline* and *Directive 060*.

55) The applicant must ensure that emissions from all combustion sources on site are reviewed in accordance with methods outlined in the *Air Quality Model Guideline*.

56) When dispersion modelling is required by the *Code of Practice for Compressor and Pumping Stations and Sweet Gas Processing Plants*, predicted ground-level concentrations of NO_2 must meet the AAAQOs, based on guidance from the *Air Quality Model Guideline*.

As described in *Directive 090*, an *EPEA* approval is required for a facility designed to process 5000 m^3/d or more of water that contains minerals. An environmental impact assessment may also be required. The applicant is expected to seek direction from the AER via email at MineralApplications@aer.ca before filing an *EPEA* application.

5.6.14 Alberta Culture

57) For proposed new facility licences or licence amendments that require a lease expansion on Freehold lands, the applicant must consult Alberta Culture to determine whether the proposed facility site will require Alberta a *Historical Resources Act* clearance before filing a licence application.

    If the proposed new or expanded lease is located on land identified in the list, the applicant must

    a) obtain a *Historical Resources Act* clearance before submitting a licence application, or

    b) if Alberta Culture will not grant clearance, disclose that in its application.

5.6.15 AER Environmental Requirements

See section 8.6 if related to developments on the southern portion of the Eastern Slopes.

5.6.16 Working Interest Participants

58) The applicant must be a working interest participant to apply for or hold a facility licence.

5.6.17 Additional Application Requirements

59) Applicants must meet the requirements in section 8.3 when planning sour gas activity where residents are located within the EPZ.

6 Pipeline Licence Applications

6.1 Overview

An applicant must apply for a licence to

- construct and operate a new pipeline that requires a new pipeline licence;
- construct and operate a new pipeline that is to be added to an existing pipeline licence;
- construct and operate a permanent pipeline, regardless of length, which is not situated wholly within the boundary of a facility surface lease or of an adjacent and abutting facility surface lease;
- construct and operate a temporary surface pipeline, except for a temporary surface pipeline for well testing or bypass or a temporary surface pipeline for water conveyance as described in sections 7 and 8 of *Directive 077: Pipelines – Requirements and Reference Tools*;
- change the materials or specifications of a licensed pipeline;
- change the operating parameters of a licensed pipeline; or
- construct a pipeline installation that includes a
  - compressor station or pump station in continuous use for more than 21 days that is associated with a pipeline carrying processed (sales) product located downstream of a facility,
  - tank farm,
  - pipeline oil loading and unloading facility, or
  - pipeline line heater (categories C and D).

A licensee must submit a *Directive 056* application within 90 days of completing a pipeline discontinuance, abandonment, removal, or line split.

The applicant or licensee must disclose in its application if it cannot meet a participant involvement or technical requirement, has outstanding concerns or objections related to its pipeline project or installation, or proposes to implement new technology. If there are outstanding concerns or objections to an exempt activity, the activity is no longer exempt from licensing, and an application disclosing the situation must be submitted.

6.2 Proliferation

As the proponent of a new facility or pipeline, the applicant has already determined that the proposed project will meet its business needs. The AER, as the approving authority, is required to evaluate the need for the proposed project in the broader public interest and encourages all applicants to consider the reuse of existing or reclaimed sites. The AER considers this interest in terms of economic, orderly, and efficient development of Alberta's energy resources.

The AER continues to receive strong input from the public, who are aware of the growth of resource development. The AER accepts the public's view that pipeline proliferation should be avoided whenever possible and practical.

Pipeline development is to be carried out in a manner that minimizes the overall impacts on the environment and public. Proliferation of pipelines occurs when new development results in more surface disturbances and impacts on the public than would be the case if existing infrastructure were used.

6.3 Licence Expiry or Extension

An applicant may select a one- or two-year term in its pipeline licence application. The licence will expire on the date given on the issued licence if right-of-way clearing, construction, or operation has not begun on that pipeline.

For new pipeline licences, the pipeline's status automatically changes from "permitted" to "operating" once the licence expiry date passes, regardless of whether the licence was acted on. A not constructed amendment application is required in cases where the licensee does not start pipeline construction. See section 6.7.1 for more information.

Due to the complexity of some pipeline developments, a licensee may be unable to act on a licence before it expires. If the licensee has not acted on the licence and it has not expired, the licensee may submit a licence extension application. See section 6 of *Manual 012* for more information.

1) If a licensee intends to proceed with a project for which its licence has expired, it must reapply. This means fulfilling all applicable regulatory requirements, including repeating the participant involvement requirements in section 3, before filing the new application.

6.4 Exempt Activities

No *Directive 056* application is required for the following exempt activities:

- pipeline replacement or pipeline liner replacement if the licensee meets the conditions in section 7(3) of the *Pipeline Rules*
- loading racks
- meter stations
- regulator stations
- line heaters associated with category B pipelines

2) The company must provide a project-specific information package to any landowners, occupants, and residents that may be directly and adversely affected by the activity.

3) The company must meet all applicable regulatory requirements for these application-exempt activities.

4) If there is an outstanding concern or objection to a company's proposed application-exempt activity, the activity is no longer exempt from licensing. The company must submit an application disclosing the outstanding concern or objection.

6.5 General Requirements and Considerations

6.5.1 Emergency Response Planning

EPZ requirements and guidelines for pipelines are outlined in *Directive 071* and *Manual 026: Emergency Preparedness and Response Guide*.

Applicants are cautioned that it is a violation of privacy legislation to disclose in the public portion of a facility, pipeline, or well licence application, any personal information that was obtained for emergency response planning purposes. Such information must be provided in confidence to the AER in connection with the emergency response planning requirements set out in *Directive 071*.

6.5.2 Setback Requirements for Select Pipelines (>10mol/kmol H_2S)

There are specific setback distances between sour natural gas and oil effluent pipelines and pipelines associated with geothermal energy or brine-hosted mineral development with H_2S content greater than10 mol/kmol and permanent dwellings, unrestricted country developments, urban centres, or public facilities.

5) The applicant must meet the applicable setback requirements in table 6 based on the calculated H_2S release volume for the proposed pipeline.

   The setbacks apply to pipelines in "permitted," "operating," or "discontinued" status.

Table 6. Setback requirements for sour natural gas and oil effluent pipelines and pipelines for geothermal or brine-hosted mineral developments (if >10 mol/kmol H_2S)

Level	H_2S release volume (m^3)	Minimum distance
1	<300	Pipeline right-of-way
2	$\geq$300 to <2000	0.1 km to individual permanent dwellings and unrestricted country developments 0.5 km to urban centres or public facilities
3	$\geq$2000 to <6000	0.1 km to individual permanent dwellings up to 8 dwellings per quarter section 0.5 km to unrestricted country developments 1.5 km to urban centres or public facilities
4	$\geq$6000	As specified by the AER, but not less than level 3

6.5.3 Pipeline Spatial Data

The AER uses pipeline spatial data to show the location of licensed pipelines under its jurisdiction.

6) Applicants must submit spatial data that

   a) is formatted in a manner acceptable to the AER,

   b) meets the content requirements of either the *Public Lands Act* for pipeline rights-of-way located on public land or *Land Titles Act* for pipeline rights-of-way located on private land,

   c) shows the right-of-way and the location of the pipeline within the right-of-way being applied for, and

   d) indicates the licensee of any rights-of-way and licence numbers of the pipelines within those rights-of-way adjacent to or being crossed by the proposed pipeline.

6.5.4 Calgary or Edmonton Transportation and Utility Corridors

7) Ministerial consent from Alberta Infrastructure must be obtained before any government authority ordering or authorizing any operation or activity that causes a surface disturbance in the transportation/utility corridors.

8) The applicant must obtain consent from Alberta Infrastructure before submitting an application to the AER.

6.5.5 Surface Pipelines

Temporary surface pipelines for well testing or bypass and temporary surface pipelines for water conveyance are approved under *Directive 077* and not *Directive 056*. See sections 7 and 8 of *Directive 077* for information.

Approvals for other surface pipelines for up to one-year usage are made under *Directive 056*.

9) The applicant must submit a *Directive 056* pipeline application for temporary surface pipelines other than those identified in sections 7 and 8 of *Directive 077* or for permanent surface pipelines.

Oil sands surface pipelines wholly within a well pad, facility, or central processing plant lease boundary do not require a *Directive 056* licence.

Oil sands surface pipelines that extend beyond the well pad, facility, or central processing plant lease boundary but are still within the blocked mineral surface lease boundary require a *Directive 056* pipeline application to be submitted and approved before construction. In such instances, the stakeholder involvement requirements conducted under *Directive 023: Oil Sands Project Applications* will satisfy the participant involvement requirements for the *Directive 056* application.

Licences for surface pipelines associated with oil sands mine approvals are not issued under *Directive 056* unless the pipelines cross a public road or watercourse.

6.5.6 AER Environmental Requirements

See section 8.6 if related to developments on the southern portion of the Eastern Slopes.

6.5.7 Conservation and Reclamation Requirements

EPEA requires that pipelines located in the white area of the province with an index of 2690 or greater (class 1) have an *EPEA* conservation and reclamation approval. Pipelines with an index value lower than 2690 (class 2) do not require the approval.

The index is determined by multiplying the outside diameter of the pipe (in mm) times the length of the pipe (in km).

For class 2 pipelines, notification to the AER is not required; however, conservation and reclamation requirements under *EPEA* must be met. When siting an upstream oil and gas site on private land, refer to AEPA's *R&R/03-2: Siting an Upstream Oil and Gas Site in an Environmentally Sensitive Area on Private Land*.

6.5.8 Pipelines Used in Geothermal and Brine-Hosted Mineral Resource Developments

Pipelines used in brine-hosted mineral and geothermal development, other than a pipeline used to distribute heat from the development of a geothermal resource, are within the scope of the *Pipeline Act* and must follow the *Pipeline Act*, the *Pipeline Rules*, and the latest version of *CSA Z662*.

6.5.9 Additional Application Requirements

10) The AER does not require applicants to acquire crossing agreements before submitting an application. However, they must be in place before construction.

11) Applicants must meet the requirements in section 8.3 when planning sour gas activity where residents are located within the EPZ.

6.6 Technical Requirements and Considerations

6.6.1 Elevated-Temperature Pipelines

For information on elevated-temperature pipelines, see section 9 of *Directive 077*.

12) If an elevated-temperature pipeline requires ABSA registration and a *Directive 056* pipeline licence, the pipeline design must be registered with ABSA before the applicant submits its licence application.

6.6.2 Stress Level

Stress level is defined as the stress in the pipe wall produced by the fluid pressure in the pipe. *Manual 012* provides stress level calculations for steel, aluminum, and thermoplastic pipeline materials. There is no stress level calculation for fibreglass or composite pipeline materials.

The applicant must meet the design limits for stress levels noted in section 26 of the *Pipeline Rules* and the design requirements in section 18(2) concerning *CSA Z662*.

13) For new pipeline materials and technologies not addressed by the *Pipeline Rules* or *CSA Z662*, the applicant must contact pipelineoperations@aer.ca before submitting its application.

6.6.3 Sour Service Pipelines

There are specific requirements in *CSA Z662* and the *Pipeline Rules* for the design, materials, construction, operation, and maintenance of sour service pipelines. Sour service is defined in clause 16 of *CSA Z662*.

14) The applicant must calculate the H_2S partial pressure or effective partial pressure to determine the need to meet *CSA Z662* sour service requirements.

6.6.4 Stainless Steel Pipelines

CSA Z662 does not address the use of stainless steel line pipe; therefore, its use may only be considered in exceptional circumstances.

15) Applicants applying to use stainless steel line pipe must complete an engineering assessment in accordance with *CSA Z662*, demonstrating its suitability for the intended purpose and the construction, operation, monitoring, and maintenance practices that would be used.

6.6.5 Pipelines Transporting Carbon Dioxide

Carbon dioxide has unique properties that necessitate specific design considerations for pipelines transporting the substance. Because some design considerations are not covered in *CSA Z662*, the AER reviews all applications to construct or amend pipelines that transport CO_2 to ensure that the design is based on sound engineering practices.

6.6.6 Connecting Pipelines with Different Substances

For pipelines licensed for sour natural gas, the AER will only approve an application if the connecting pipeline is also licensed for sour natural gas. For pipelines licensed for HVP products, the AER will only approve an application if the connecting pipeline is also licensed for HVP products.

The commingling of natural gas and oil effluent substances is permitted in accordance with the requirements of section 10 of *Directive 077*.

The AER will not approve an application for a pipeline with H_2S that is to tie into an existing pipeline with a lower H_2S content than that of the proposed pipeline unless an acceptable gas blending scheme is proposed.

6.6.7 Natural Gas Stream Blending

Blending natural gas streams involves combining streams with different H_2S content (higher and lower) to achieve a blend lower in H_2S than the stream with the highest concentration. Blending a liquid stream with a gas stream is not permitted. The applicant's blending control system design must meet the requirements in section 24 of the *Pipeline Rules*.

16) The applicant must indicate in its application if it plans on implementing natural gas stream blending.

6.6.8 Sour Natural Gas Injection

When a producing reservoir has an approved enhanced recovery scheme that permits sour natural gas injection, the pipeline licensee must review the impacts of the scheme operation on the pipeline materials and operating parameters.

17) The applicant must evaluate the potential for

    a) gas cap breakthrough,

    b) reclassification of existing pipeline systems due to an increase in H_2S content,

    c) reclassification of producing wells as critical wells, and

    d) licence amendment applications to meet CSA sour service material requirements for the pipelines affected.

6.7 Licence Amendments

18) The licensee must submit a pipeline licence amendment application for

    a) not constructed pipeline,

    b) substance or H_2S change,

    c) MOP change,

    d) flow reversal,

    e) internal protection installation or removal

    f) pipeline discontinuance,

g) pipeline abandonment,

h) pipeline removal

i) a pipeline line split, and

j) pipeline resumption.

6.7.1 Not Constructed Pipeline

Receiving a "not constructed" pipeline application notifies the AER that the licensee will not be constructing the licensed pipeline.

19) If the licensee will not be constructing the licensed pipeline, it must

a) meet the participant involvement requirements in section 3.8.2.1 and

b) file the application 30 days before the expiry of the pipeline licence.

6.7.2 Substance or H_2S Change

A pipeline licence is substance and H_2S content specific. A licensee must apply to amend its licence when intending to transport a substance or H_2S content other than that stipulated on its current licence.

20) Before submitting a substance or H_2S change application, the licensee must

a) meet any applicable participant involvement requirements in section 3.8.2.2;

b) complete an engineering assessment for service fluid change in accordance with *CSA Z662*; and

c) take appropriate actions to ensure continued compliance if the substance or H_2S change affects any of the following:

i) pipe and component material suitability (*Pipeline Rules* and *CSA Z662*)

ii) CSA class location redesignation (*CSA Z662*)

iii) pipeline integrity

iv) pressure testing (*Pipeline Rules* and *CSA Z662*)

v) depth of pipeline cover (*Pipeline Rules* and *CSA Z662*)

vi) pipeline warning signs (*Pipeline Rules* and *CSA Z662*)

vii) changes to the licensee's integrity management program (*CSA Z662*)

viii) substance and H_2S content compatibility with upstream and downstream pipelines (*Pipeline Act*)

ix) ERP changes (*Directive 071*)

x) H_2S release volume level designation changes and setbacks (see section 6.5.2)

21) The licensee must obtain approval under *Directive 056* before changing a pipeline's licensed substance or H_2S content.

6.7.3 Maximum Operating Pressure Change

22) Before submitting an application for an MOP change, the licensee must meet any applicable participant involvement requirements in section 3.8.2.3.

23) The licensee must obtain approval under *Directive 056* before changing a pipeline's MOP.

6.7.3.1 Maximum Operating Pressure Increase

24) Before submitting an application for an MOP increase, the licensee must

a) complete an engineering assessment for the MOP increase in accordance with *CSA Z662* and

b) take appropriate actions to ensure continued compliance if the MOP increase affects any of the following:

i) pipe and component material suitability (*Pipeline Rules* and *CSA Z662*)

ii) CSA class location redesignation *(CSA Z662*)

iii) pipeline integrity

iv) pressure testing (*Pipeline Rules* and *CSA Z662*)

v) changes to the licensee's integrity management program (*CSA Z662*)

vi) MOP mismatches with upstream and downstream pipelines (*Pipeline Rules* and *CSA Z662*)

vii) ERP changes (*Directive 071*)

viii) H_2S release volume level designation changes and setbacks (see section 6.5.2).

6.7.3.2 Maximum Operating Pressure Decrease

25) Before submitting an application for an MOP decrease, the licensee must take appropriate actions to ensure continued compliance if the MOP decrease affects any of the following:

a) CSA class location redesignation (*CSA Z662*)

b) changes to the licensee's integrity management program (*CSA Z662*)

c) MOP mismatches with upstream and downstream pipelines (*Pipeline Rules* and *CSA Z662*)

d) ERP changes (*Directive 071*)

e) H_2S release volume level designation changes and setbacks (see section 6.5.2)

6.7.4 Flow Reversal

26) Before submitting a flow reversal application, the licensee must

a) meet any applicable participant involvement requirements in section 3.8.2.4 and

b) take the appropriate mitigative action to ensure continued compliance with the following:

i) changes to the licensee's integrity management program (*CSA Z662*)

ii) substance and H_2S content compatibility with upstream and downstream pipelines (*Pipeline Act*)

iii) MOP mismatches with upstream and downstream pipelines (*Pipeline Rules* and *CSA Z662*)

iv) ERP changes (*Directive 071*)

v) H_2S release volume level designation changes and setbacks (see section 6.5.2).

27) The licensee must obtain approval under *Directive 056* before changing the pipeline's flow direction.

6.7.5 Internal Protection

The applicant or licensee may choose to install internal protection (e.g., a liner or an internal coating) to improve or maintain the integrity of its pipeline. The following internal protection types are permitted:

- freestanding fibreglass pipe as a liner (considered pressure containing)
- freestanding reinforced composite pipe as a liner (considered pressure containing)
- freestanding thermoplastic pipe as a liner (considered pressure containing)
- expanded thermoplastic liner (considered an internal corrosion barrier and not pressure containing)
- thin-film internal coatings applied during manufacture (considered an internal corrosion barrier and not pressure containing)
- thin-film internal coatings applied in situ (considered to be internal corrosion barrier and not pressure containing)

- cement coating (considered an internal corrosion barrier and not pressure containing)

28) The *Directive 056* application must identify the type of internal protection the applicant or licensee plans to install.

29) The licensee must obtain approval under *Directive 056* before installing or removing internal protection.

30) Expanded thermoplastic liners and the supporting pressure-containing pipe must be designed and pressure tested according to current CSA standards. Consideration should be given to temperature design and fluid compatibility (e.g., liquid hydrocarbon absorption). For sour service, the supporting pressure-containing pipe must meet sour service requirements.

31) If the applicant or licensee plans to use internal protection other than that permitted by the AER, it must contact pipelineoperations@aer.ca before submitting an application.

6.7.6 Pipeline Discontinuance

Pipeline discontinuance is defined as the temporary deactivation of a pipeline or part of a pipeline.

32) When discontinuing a pipeline, the licensee must

    a) discontinue the pipeline in accordance with the *Pipeline Rules*,

    b) retain setback distances (see section 6.5.2), and

    c) submit a discontinuance application within 90 days of completing the pipeline discontinuance.

33) A discontinued pipeline system with underground tie-ins must be licensed to one licensee and only include discontinued pipelines.

34) An application to discontinue a pipeline system with underground tie-ins must identify all the pipeline licences and lines included in the discontinued pipeline system.

6.7.7 Pipeline Abandonment

Pipeline abandonment is defined as the permanent deactivation of a pipeline or part of a pipeline.

35) When abandoning a pipeline, the licensee must

    a) meet the participant involvement requirements in section 3.8.2.7,

    b) abandon the pipeline in accordance with the *Pipeline Rules*, and

    c) submit an abandonment application within 90 days of completing the pipeline abandonment.

36) An abandoned pipeline system with underground tie-ins must be licensed to one licensee and only include abandoned pipelines.

37) An application to abandon a pipeline system with underground tie-ins must identify all the pipeline licences and lines included in the abandoned pipeline system.

6.7.8 Pipeline Removal

Pipeline removal is defined as the removal of a pipeline or part of a pipeline.

38) When removing a pipeline, the licensee must

a) meet the participant involvement requirements in section 3.8.2.8,

b) remove the pipeline in accordance with the *Pipeline Rules*, and

c) submit a removal application within 90 days of completing the pipeline removal.

39) If the licensee plans to remove just part of a pipeline, it must also submit a line split application identifying the sections for removal and those remaining in place.

6.7.9 Pipeline Line Split

A pipeline line split is the division of a line segment into multiple segments, with each segment having an assigned line number.

40) When completing a pipeline line split, the licensee must

a) meet any applicable participant involvement requirements in section 3.8.2.9 and

b) submit a line split application within 90 days of completing the line split.

6.7.10 Pipeline Resumption

Pipeline resumption is defined as resuming operations of a pipeline or part of a pipeline to its original licensed parameters. An application for resumption is not required when the pipeline has been maintained in accordance with the licensee's integrity management program and is being placed into operation within 24 months of ceasing operation.

The licensee must apply for a pipeline resumption in accordance with section 82 of the *Pipeline Rules*.

41) Before submitting a resumption application, the licensee must

a) meet any applicable participant involvement requirements in section 3.8.2.10,

b) complete an engineering assessment for the resumption of the pipeline in accordance with *CSA Z662*, and

c) confirm the suitability of the pipeline design and integrity for the intended service.

42) The licensee must obtain approval under *Directive 056* before resuming the pipeline.

43) When resuming a pipeline included in a previous pipeline system discontinuance or abandonment, the licensee must either

a) resume the entire system or

b) isolate the pipeline being resumed from the discontinued or abandoned pipeline system.

44) A resumption application for a pipeline system that was discontinued or abandoned must identify all pipeline licences and lines in the system being resumed.

45) If the pipeline is being resumed from "discontinued" status and was not discontinued in accordance with the *Pipeline Rules*, the licensee must indicate in its resumption application what discontinuance requirement was not met.

46) If the resumption application is the result of an AER-directed licence transfer under section 18(7) of the *Pipeline Act*, the licensee must indicate this in its resumption application.

6.7.11 Pipeline Replacement or Pipeline Liner Replacement

47) If the pipeline replacement or pipeline liner replacement application conditions in section 7(3) of the *Pipeline Rules* are not met, the licensee must submit the required applications to complete its pipeline replacement or pipeline liner replacement.

6.8 Pipeline Installation

A pipeline installation is defined as any equipment, apparatus, mechanism, machinery, or instrument incidental to the operation of a pipeline. This includes a compressor station, pump station, tank farm, and pipeline loading and unloading facility associated with pipelines carrying processed (sales) product. These installations would be located downstream of a gas processing facility or battery. Category C and D line heaters are considered pipeline installations, although all other upstream facilities are licensed under section 5 of *Directive 056*.

48) When applying for a pipeline installation, the applicant must meet the participant involvement requirements in section 3.

49) When amending a pipeline installation, the licensee must obtain approval under *Directive 056* before proceeding with the proposed amendment activity.

50) Where applicable, the applicant must meet

a) noise requirements defined in *Directive 038*,

b) AER storage requirements (see *Directive 055*), and

c) AER spacing requirements as described in the *OGCR*.

6.8.1 Process Flow Diagrams

51) The applicant must attach a PFD for all pipeline installation applications.

a) The PFD must identify all existing and proposed equipment at the pipeline installation. Proposed equipment must be identified in the legend and annotated on the diagram.

Diagrams must accurately represent the actual operations of the installation and contain the correct location and applicant name.

b) The applicant must clearly identify the following on the PFD:

i) storage tanks

ii) sources of all inlets, receipts, and deliveries, including all fuel lines, flare lines, and vent points

iii) safety equipment

6.8.2 NO_x Emissions

If NO_x emissions are present, it is the applicant's responsibility to ensure that the facility meets the AAAQOs for NO_2. It is possible that facilities exempt from registration under *EPEA* could exceed the AAAQOs. It is in the company's best interest to conduct modelling to ensure that its facility will meet the AAAQOs. In order to demonstrate that the facility meets the AAAQOs, the AER may require that the applicant provide NO_x modelling.

52) The applicant must design the pipeline installation to meet the requirements set out in AEPA's *Code of Practice for Compressor and Pumping Stations and Sweet Gas Processing Plants*.

53) The applicant must register all compressor and pumping stations with the AER before commencing operations if the total NO_x emissions are greater than 16 kg/hr.

54) New and additional natural gas-driven reciprocating engines greater than 600 kW at full load must not emit more than 6 grams of NO_x per kilowatt-hour (g/kWh).

55) The applicant must meet the following requirements when NO_x emissions are present at facilities that require registration or approval with the AER:

a) Dispersion modelling must be conducted in accordance with AEPA's *Air Quality Model Guideline*.

b) Based on dispersion modelling, predicted NO_2 concentrations must meet the AAAQOs using guidance from the *Air Quality Model Guideline*.

c) Standby equipment used only for emergency purposes can be excluded from dispersion modelling.

d) The engine exhaust stack height must be set in accordance with the direction given in AEPA's *Code of Practice for Compressor and Pumping Stations and Sweet Gas Processing Plants*.

e) NO_x emissions from steam generating units, heaters, and boilers can be excluded from dispersion modelling if their combined contribution is less than 3% of the total NO_x emissions.

6.8.3 Plot Plans

56) A plot plan must be submitted with each pipeline installation application that clearly indicates the on-lease location of all the equipment (with the exception of valves) indicated on the PFD. It must also show at least 100 m past the edge of the lease to demonstrate that all off-lease spacing requirements have been met (e.g., distance to a residence, water bodies, forestation, or road allowance).

57) The applicant must meet the spacing requirements of the *OGCR*.

6.8.4 Noise

All pipeline installations under the AER's jurisdiction must meet the requirements of *Directive 038*.

An NIA will ensure that the applicant has considered possible noise impacts before a pipeline installation is constructed or operated. The NIA predicts the expected design sound level from the pipeline installation at the nearest or most impacted residence.

58) Applicants must discuss noise matters with area residents (see section 3).

59) An NIA must be completed before submitting a pipeline installation application for any new permanent pipeline installation or for modifications to existing permanent pipeline installations if there is a reasonable expectation of a continuous or intermittent noise source.

For the purpose of an NIA, a permanent pipeline installation is a pipeline installation in operation for more than two months.

60) If the NIA indicates the permissible sound level will be exceeded, the applicant must consider further mitigative measures.

Where mitigative measures are not practical, the applicant must explain why in its application.

61) The AER expects the applicant to use a reasonable technical basis for the values presented in the NIA, such as computer modelling, field measurements of similar equipment, accepted acoustical engineering examples from literature, and calculations.

62) If the applicant is using manufacturer's specifications, the sound level ratings must represent free or far-field conditions. Sound level ratings at 1 m are not acceptable for inverse square law calculations.

7 Well Licence Applications

7.1 Overview

An applicant must apply for a well licence for

- a new oil, gas, crude bitumen, geothermal, or brine-hosted mineral well,
- a water well greater than 150 m deep,
- a new disposal or injection well, including those involving CO_2,
- a cavern scheme well,
- re-entering a well after abandonment of the original wellbore,
- resuming drilling operations after original rig release,
- an oil sands evaluation well, an evaluation well, or test hole,
- a CBM well, or
- drilling a well through a potential hydrocarbon zone for any other purpose.

A licence is also required for wells that will be drilled deeper than 150 m to supply water for domestic or stock watering purposes. Please contact the AER for details and instructions.

A licensee must amend an approval or may file information updates, depending on the circumstances as outlined in table 7 of *Manual 012*, to certain licence details for

- amending certain attributes of a previously issued well licence before spud or rig release (see *Manual 012*),
- deepening an existing well while the rig is on hole,
- changing certain details after drilling occurs,
- converting an oil sands evaluation well to a conventional producing well or observation well after it has been drilled, or
- converting an existing well to a different regulatory framework (e.g., converting a well under the *OGCR* to produce geothermal energy under the *GRDR* or brine-hosted mineral resources under the *BMR*).

If any of the following are true, the applicant must disclose this in its well licence application:

- The applicant cannot meet a technical requirement.
- The applicant applied for a regulatory variance.
- The applicant has received a preapplication variance.

- The applicant cannot meet all participant involvement requirements.
- The applicant proposes to implement new technology.
- There are outstanding concerns or objections to the application.

If there are outstanding concerns or objections to an exempt activity, the activity is no longer exempt from licensing, and an application disclosing this information must be submitted.

7.2 Licence Expiry, Extensions, and Cancellations

An applicant may select a one- or two-year term in its well licence application. Applicants selecting a two-year term must update their public involvement notifications and review survey plan information before construction activities. Licences will expire on the date given on the issued licence if construction or operations have not started. After the expiry date has been reached, the AER will cancel the expired licence from its active records, and it cannot be extended. A new well licence application would have to be filed.

A licensee may also cancel its licence if the licence is still active and is no longer required.

If a licensee cannot act on a licence before the expiry date, the licensee may apply for an extension of the expiry date by filing an amendment application to extend the licence term.

1) If requesting a term extension on a one-year licence, the licensee must update its participant involvement notifications and review its survey plan before construction.
2) If changes to the survey plan are needed, the changes must be prepared and certified by an Alberta Land Surveyor. If the details of the well licence require altering, the licensee must file an amendment.
3) If there are no changes to the survey plan, or changes are noted that do not alter the licence details, the licensee must keep records verifying the date notifications were sent and the accuracy of the survey plan.

7.3 Category Type and Consultation and Notification Requirements

The category type and the consultation and notification requirements for wells are listed in table 4. The category type of a well is determined by the H_2S content, H_2S release rate, and proximity to the public.

7.4 Exemptions

Well licence applications are not required for

- wells drilled to a depth of less than 150 m that are not intended to encounter or produce hydrocarbons,
- wells drilled to discover or evaluate a solid inorganic mineral (e.g., limestone quality test well),
- oil sands evaluation wells drilled within an approved mine site in accordance with section 4(5) of the *Oil Sands Conservation Rules*, or
- wells that have been spudded and that will be completed to the licensed depth and terminating formation at a later date.

7.4.1 Abandoned Well Remediation

Approvals for abandoned well remediation do not require a *Directive 056* application. Companies responsible for the re-entry, repair, and reabandonment of a well must submit a nonroutine abandonment request to the AER consistent with section 3.3 of *Directive 020: Well Abandonment*. The request should indicate the reason for the re-entry, a plan for resolution of the issue, and a statement about whether the company is the current licensee of the well, holds the mineral rights, and has a current surface lease agreement. If the request is approved, the AER will issue a letter of approval. If the company is not the current licensee, a *Directive 056* application may be required.

Before submitting an application, authorization for re-entry, repair, and reabandonment must be obtained from Alberta Energy, if applicable.

7.5 Licence Amendments and Information Updates

There are two processes for changing certain attributes on a well licence after it is issued: a licence amendment or an information update. Table 7 in *Manual 012* identifies the attributes that can be changed, the correct process to use, and the applicable timelines to complete those changes.

A licence amendment is considered an "application" under *REDA* Part 2, whereas an information update is not. Therefore, licence amendment applications are subject to public notice, statements of concern, and possible hearings. Information updates are not.

Only the licensee may file a well licence amendment or information update. Changing specific data requires

- filing an amendment application and receiving approval before drilling,
- filing an amendment application to convert a well initially licensed as an oil sands evaluation well type to another type of well after drilling the well has occurred,

- filing an amendment application to convert a well drilled under one regulatory framework to a well under another regulatory framework, or
- filing an information update after a well has been drilled to modify certain attributes on the licence.

If a well licence has not been acted upon, it cannot be amended to a different well type nor converted another regulatory framework. The well licence would need to be cancelled and a new well licence application filed.

The licensee must amend or submit an information update to correct inadvertent data entry errors or transposition of numbers.

7.5.1 Amendments

A licensee seeking to alter specific approval details which appear on the licence must do so before drilling commences by filing and receiving an amendment approval. Amendments to a well licence must be approved by the AER before the licensee commencing an activity.

Licence details that must be amended are those critical to the AER's decision to approve the licence before the well is drilled. If this information is changed through an amendment, the AER re-evaluates the approval and, if it approves of the proposed amendment, issues a formal amendment to replace the existing approval.

4) The licensee must meet the participant involvement requirements in section 3 to file a well licence amendment.

5) Applicants filing to convert an oil sands evaluation well to a conventional producing or observation well must first apply for a permanent land disposition and obtain a site-specific survey plan and spatial data as described in section 7.7.1.

7.5.2 Information Updates

6) A licensee may submit an information update to report changes to a limited number of specific surface and subsurface information fields on a licence after the well is drilled. Information updates are necessary to ensure data integrity in the AER's records.

7) Bottomhole location changes and revisions to the unique well identifier of a well which arise from a directional survey must be initiated by the licensee through an information update.

7.6 Re-entry, Resumption, and Deepening

Re-entry and resumption both refer to conducting further activity at an existing wellbore. When done by the existing licensee, it is called "resumption." When done by someone else, it is called "re-entry."

8) To re-enter an abandoned wellbore, the new licensee must apply for a new licence. If approved, the new licensee assumes responsibility for the well and any associated liabilities, even if operations are never conducted at the well.

9) Re-entry is only permitted for wells initially licensed under the *OGCR*. To re-enter or resume operations of an abandoned well under the *GRDR* or *BMR*, the licence must first be transferred, then converted to change the authorized purpose, and then resumed if additional drilling is required.

10) If the current licensee intends to conduct additional drilling activity beyond the limits of the original licence or enter one of their abandoned wells, it must apply for a resumption of its existing licence.

11) The licensee must amend the well licence while the rig is on hole if the licensee is deepening an existing well resulting in

   a) a change to the well category or type, or

   b) a change to the terminating formation.

If the change in total depth does not result in either (a) or (b), a change to the depth is captured through the submission of the licensee’s drilling records.

7.7 Technical Requirements

7.7.1 Spatial Data and Survey Plans

12) The applicant must submit digital spatial data that

   a) is formatted in a manner acceptable to the AER,

   b) meets the content requirements of either the *Public Lands Act* for well locations on public land or the *Land Titles Act* for well locations and the lease boundary on private land, and

   c) shows the location of the well or wells are within the lease boundary.

13) The applicant must attach a survey plan that

   a) meets all requirements stated in section 2.020 of the *OGCR*;

   b) provides sufficient detail to accurately identify surface topography, surface improvements, and access roads and is formatted in a manner acceptable to the AER;

   c) is current and valid, meaning

      i) less than 12 months old from the date of creation and certification or

      ii) if more than 12 months from the date of certification is noted as correct by survey notation by an Alberta Land Surveyor;

d) shows the location of the well tied by bearings and distance to a monument or, in the case of a well in unsurveyed territory, the location determined in accordance with the Alberta Land Surveyors Association *Manual of Standard Practice*;

e) shows the relation of the well to the boundaries of the quarter section shown by the coordinates from the two boundaries of the quarter section that are also the boundaries of the section (assuming a 20 m wide road allowance) and by calculated distances to the interior boundaries of the quarter section;

f) shows the relation of the well location to the surface topography within 200 m of the well, including

   i) elevation of any significant water bodies and

   ii) sufficient information to establish the general character of the topography and any predominant drainage patterns;

g) in the case of long access roads (i.e., outside the 200 m radius) or where the well is close to survey section lines, shows sufficient information to establish the general character of the topography, predominant drainage patterns, and surface improvements;

h) shows the relation of the well location to

   i) surface improvements,

   ii) wells,

   iii) coal mines, whether working or abandoned, and

   iv) water wells within 200 m of the well;

i) indicates the depth of the water if the proposed well is in a water-covered area; and

j) for new CBM wells completed above the base of groundwater protection, applicants must meet the additional requirements found in *Directive 035* regarding survey plans and maps.

14) The survey plan should also reflect the distance to the nearest

   a) dwelling (whether occupied part time or full time; e.g., house, seasonal cottage, trapper's cabin),

   b) publicly used development (e.g., church, community centre, campground, curling rink),

   c) place of business, or

   d) other surface development where members of the public may gather.

7.7.2 Well Names

Well names are unique and created at the time of licensing as set out in section 13.020 of the *OGCR*. Well names must be confirmed by the applicant. The applicant can propose to insert special characters in the name between the licensee abbreviation and the field name to distinguish the name from any existing well name.

15) Names for wells licensed under the *BMR* must contain "MIM" in the special characters space immediately following the licensee's name or abbreviation. For a well under the *GRDR*, the applicant must insert "GT" in the well name position noted above.

A change to the well's name may be desired when the licensee changes, the bottomhole location is revised, or a regulatory conversion of the well type is initiated. An amendment application or an information update may be filed to change well names to remain consistent with current information (see *Manual 012* for information on which process is appropriate when).

7.7.3 Emergency Response Planning

The EPZ for wells containing H_2S is based on the release rate for the well.

Applicants are cautioned that it is a violation of privacy legislation to disclose in the public portion of a facility, pipeline, or well licence application any personal information that was obtained for emergency response planning purposes. Such information must be provided in confidence to the AER, in connection with emergency response planning requirements set out in *Directive 071*.

7.7.4 Critical Sour Well

A critical sour well is one that meets any of the following criteria:

- RR $\geq$2.0 m^3/s
- RR $\geq$0.3 m^3/s but <2.0 m^3/s and the well is located within 5 km of an urban centre
- RR $\geq$0.1 m^3/s but <0.3 m^3/s and the well is located within 1.5 km of an urban centre
- RR $\geq$0.01 m^3/s but <0.1 m^3/s and the well is located within 500 m of an urban centre

16) If the proposed well is critical or deemed to be category E, the applicant must meet the drilling requirements detailed in *Directive 036: Drilling Blowout Prevention Requirements and Procedures*, and *IRP Volume 1: Critical Sour Drilling*.

7.7.5 Minimum Casing Testing Requirements – Re-entry and Resumption of Drilling

The following requirements apply when re-entering an existing wellbore, whether abandoned or not, to deepen, whipstock, recomplete (abandoned well only), or recomplete horizontally.

For the tests set out below, the required pressures are applied at surface and are based on a wellbore fluid density of 1000 kg/m^3. The test pressure is adjusted according to the fluid density in the wellbore at the time of the test. For a satisfactory pressure test, a stabilized pressure is maintained over a 10-minute interval.

17) For all categories of wells with only surface casing set:

   a) Before starting re-entry or resumption of drilling operations, the licensee must

      i) ensure that there is sufficient casing set and cemented in the well for well control purposes (see *Directive 008*) and

      ii) pressure test the existing casing to the lesser of 7000 kPa or 50 times the casing setting depth (m).

18) For category B, C, or D wells that will be drilled overbalanced or recompleted:

   a) Before starting re-entry or resumption of drilling operations, the licensee must

      i) ensure that there is sufficient casing set and cemented in the well for well control purposes (see *Directive 008*), and

      ii) pressure test the existing casing to 67% of the bottomhole pressure at the casing setting depth or the depth at which the window will be cut.

   b) If the existing casing is to be used for production purposes, before placing the well on production, the licensee must

      i) run a casing inspection log or combination of logs, fully interpreted on a joint-by-joint basis, which

         – determines the percentage penetration of anomalies,

         – distinguishes between internal and external corrosion, and

         – has the ability to detect holes, pits, perforations, metal loss, and metal thickness;

      ii) use the results of the casing inspection log in the following equation to verify that the minimum internal yield (P_y) of the existing casing meets the minimum required casing burst pressure set out in *Directive 010*:

$$P_y = \frac{2Y_p t}{D}$$

      where P_y is the minimum internal yield (kPa), Y_p is the specified minimum yield strength (kPa), t is the reduced wall thickness (mm; minimum remaining well thickness—not an average), and D is the nominal outside diameter (mm); and

iii) pressure test the casing to a pressure of 85% of the minimum required casing burst pressure set out in *Directive 010*.

19) For category B, C, or D wells that are drilled underbalanced and for any category E well:

a) Before starting re-entry or resumption of drilling operations, the licensee must

i) ensure that there is sufficient casing set and cemented in the well for well control purposes;

ii) run a casing inspection log or combination of logs, fully interpreted on a joint-by-joint basis, which

– determines the percentage penetration of anomalies,

– distinguishes between internal and external corrosion, and

– has the ability to detect holes, pits, perforations, metal loss, and metal thickness;

iii) use the results of the casing inspection log in using the equation in requirement 18(b)(ii) to verify that the minimum internal yield (Py) of the existing casing meets the minimum required casing burst pressure set out in *Directive 010*; and

iv) pressure test the existing casing to 67% of the highest anticipated formation pressure that will be encountered.

b) If the existing casing is to be used for production purposes, before placing the well on production, the licensee must

i) run another casing inspection log (this casing inspection log may be a log that has regard for internal wall loss and may be compared to the data from the log conducted before drilling [see requirement 18(b)(ii) above]),

ii) ensure that the formula set out in requirement 18(b)(ii) is now satisfied based on the least wall thickness remaining,

iii) ensure that the minimum internal yield (Py) of the existing casing meets the minimum required casing burst pressure set out in *Directive 010*, and

iv) pressure test the casing to a pressure of 85% of the minimum required casing burst pressure set out in *Directive 010*.

20) To request a variance to the pressure test parameters or from the required casing inspection logs for a re-entry or resumption of a well, the licensee must identify the variance in its application. Note that there are certain situations in which the AER will not consider granting variances.

7.7.6 Terminating Formation

For the purpose of well licensing, the terminating formation is defined as the deepest formation in which the well will terminate and which the applicant has the right to produce for all intended purposes of the well.

The applicant may drill to a maximum overhole depth of 15 m below the base of the terminating formation. This overhole depth is permitted to accommodate logging tools and casing.

21) The applicant must not identify any formations within the 15 m overhole as the terminating formation on a well licence application unless the applicant holds the mineral rights.

22) The applicant must have the permission of the mineral rights holder, whether Crown or Freehold owner or lessee, to exceed the 15 m maximum overhole depth.

7.7.7 AER Classifications

The AER classification is the "pre-spud" assignment given to each well as based on the geological complexities and the known existence of hydrocarbon accumulations (pools) and other energy resources in the area where a new well is to be drilled. This classification system is designed to distinguish between exploration and exploitation activity and takes into account the other unique well types drilled in Alberta. See table 7 for the individual well classification descriptions and figure 1 for a graphical representation of wells licensed under the *OGCR*.

Table 7. AER classification

AER classification	Description
Exploratory (XPL)	When targeting hydrocarbon resources, an XPL well is drilled to discover new pools or to extend existing pools by a considerable distance. An XPL well may also be exploring for pools deeper than what is known to exist and be productive in an area. If attempting to extend an existing pool, a XPL well is typically at least two drilling spacing units (DSUs) beyond the boundaries of the known pools. In circumstances where the new well is in relatively close proximity to the limits of known pools but geological complexity and technical data suggest that a new pool will be encountered, the XPL classification is appropriate. If a well is located within or near a shallow pool but is targeting new, undiscovered pools below the existing pool, the XPL classification also applies. Wells drilled under the *GRDR* to obtain reservoir properties and to produce unexplored geothermal resources are classified as XPL.

AER classification	Description
Development (DEV)	When targeting hydrocarbon resources, the objective of a DEV well is to further exploit or extend known pools. The well may be inside of the established limits of the pool or in close proximity to the edge of the pools. A new well drilled immediately adjacent to or within 1 to 2 DSUs beyond would be classified as a DEV well. The DEV classification should be used even if the well is drilled slightly deeper than the target pool, especially where the deeper strata to be penetrated have no hydrocarbon-bearing potential. Wells licensed with a well type of production and substance of bitumen are DEV. Wells drilled under the *GRDR* to access and further develop the geothermal resource established in a formation are classified as DEV. Wells drilled under the *BMR* to produce mineral brine for evaluation purposes or for recovering minerals from groundwater are classified as DEV. However, wells drilled for evaluation purposes pursuant to brine-hosted metallic and industrial minerals licence tenure may not be used to recover brine-hosted minerals.
Re-entry (REN)	A REN classification is assigned to a well that re-enters an existing wellbore for the purpose of recompleting the well as a producer or service well with no new strata being drilled. If new strata are to be drilled (e.g., by deepening, whipstock, or sidetracks), the well is assigned the appropriate AER classification. This classification is only given to wells licensed under the *OGCR*.
Development Service Well (DSW)	A DSW well is drilled to introduce fluids into a wellbore or formation or to observe the performance of resource development. Wells drilled under the *GRDR* to inject brine or water or under the *BMR* to inject fluid into underground formations are classified as DSW. Wells used to gather pressure or temperature data or to monitor resource development in general are also classified as DSW. Wells drilled to inject carbon dioxide (CO_2) into approved subsurface formations to enhance oil recovery or used for injection of CO_2 for storage are classified as DSW. Water injection, steam injection, and observation wells are other examples of DSW wells.
Evaluation Oil Sands (OV)	An OV well is drilled in an oil sands area to evaluate the oil sands and is not intended to produce hydrocarbons. Such wells will be licensed under section 2.030 of the *OGCR*.
Test Hole (TH)	A TH well is drilled for geological and geophysical stratigraphic evaluation purposes and is not intended to produce, operate, or expected to encounter hydrocarbons. Such wells will be licensed under section 2.030 of the *OGCR*.
Experimental (EX)	An EX well is part of an AER-approved experimental scheme. Such wells will be licensed under section 2.030 of the *OGCR*.

AER classification	Description
Other (OTH)	A well licensed under section 2.020 or 2.040 of the *OGCR*, not associated with brine-hosted mineral resource development, and drilled for water production; brine production; gas storage; water, brine, acid gas, or waste disposal; or any other purpose not covered by other AER classifications is classified as OTH. Wells drilled to evaluate deep subsurface reservoirs to determine the suitability of their geologic and geophysical properties to sequester captured CO_2 under a carbon sequestration evaluation agreement are classified as OTH and licensed under disposal (CCS). Wells drilled for active sequestration of captured CO_2 under a carbon sequestration agreement are also classified as OTH. A well drilled to test or use new geothermal technology as set out in in *Directive 089* is classified as OTH.

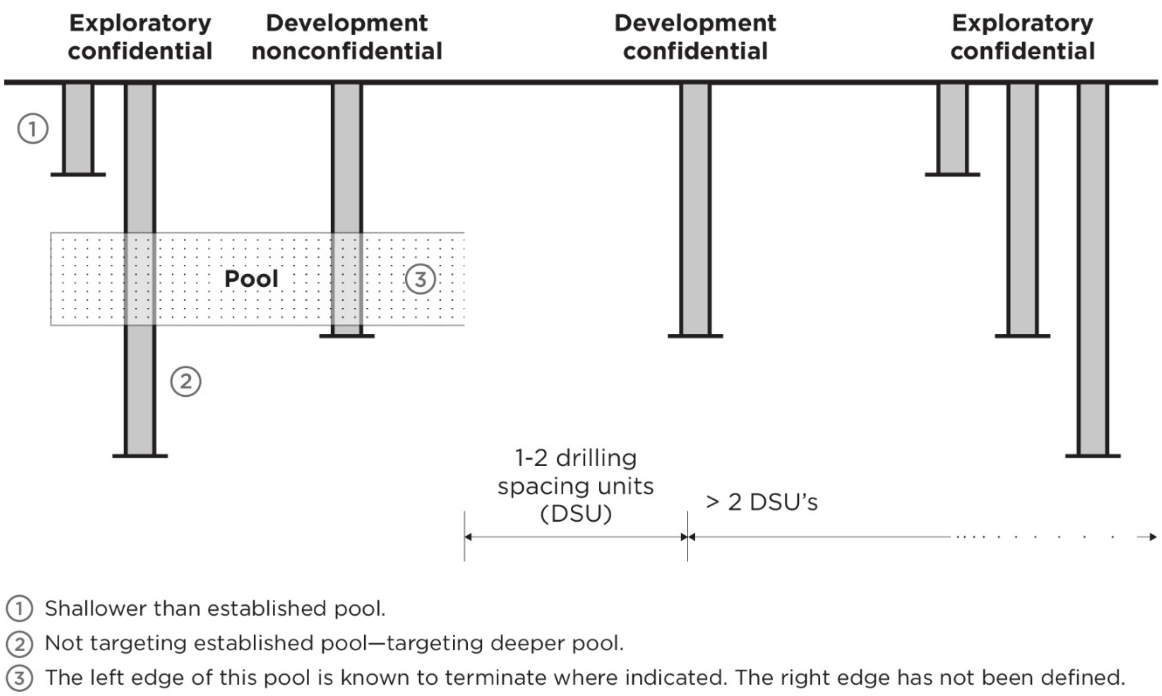

Figure 1. How to classify a well licensed under the *OGCR*

7.7.7.1 Technical Considerations

The following describes the technical considerations for AER classifications:

- The AER classification takes into account all zones to be penetrated by the well and the proximity of the well to pre-existing hydrocarbon pools or underground formations that may contain geothermal or brine-hosted mineral resources.
- The AER classification of activities involving hydrocarbons takes into account any pre-existing exploited offset pools and pre-existing wells with logs or tests that strongly suggest the

presence of pools, although the pools may not have yet been exploited. In both cases, the AER would consider the pools as previously discovered.

- The AER's official designation of pool orders (formerly known as G orders) have no bearing on the AER classification. This is because they may not have been issued for nearby pools and because their boundaries may not have been updated to reflect current knowledge regarding areal extent and continuity of pools.
- Pools and pool orders are not considered when assigning the appropriate classification or confidentiality to drilling activities looking to recover geothermal or brine-hosted mineral resources.

7.7.7.2 Process and Review Information

The following describes the process and review considerations for AER classifications:

- AER classifications are to be selected by the applicant in accordance with the definitions provided in table 7.
- The AER classification is not reviewed by the AER before issuing the well licence.
- It is strongly recommended that the licensee review its well licence to ensure accuracy of the AER classification selection. In the event that the licensee detects an incorrect selection, a letter may be sent to the AER requesting a revision. The AER will issue a letter acknowledging the revision. As is the case with new licences issued, the revision request will not be reviewed for correct selection.
- Because the AER classification is based upon pre-spud information, it would not be appropriate for a licensee to request a classification revision after the well has been drilled and results have been obtained.
- The AER may review a well's classification at any time.
- If the AER requires additional data in support of the licensee's AER classification selection, a letter will be sent to the licensee indicating that
  - the licensee has 30 days to file a submission package in support of its AER classification selection, and
  - in the absence of a submission within 30 days, the AER will revise the classification to the AER planned revision stated in the letter.
- Submission packages in support of a licensee's AER classification should include a covering letter stating the views of the licensee and any pre-spud technical information (maps, seismic, etc.) in support of retaining the original AER classification selection.

- The AER will review submissions and issue a written decision. In some cases, meetings to exchange information may be necessary.

The AER records the AER classification assignment for all wells drilled in Alberta.

7.7.8 Assigning Initial Confidentiality to New Wells

The initial confidential status on new wells is based on the provisions described in section 12.150 of the *OGCR*, section 15 of the *Oil Sands Conservation Rules*, section 95 of the *GRDR*, and section 103 of the *BMR*. In assigning the initial confidentiality to new wells, the AER will require the applicant to choose a confidential designation of either "confidential" or "nonconfidential" only. The AER will assess the applicability of the "confidential below" designation only for *OGCR*-licensed wells and only after a well is drilled and its technical data is reviewed by the AER to confirm that the conditions described in section 12.150(2)(f) of the *OGCR* apply. Table 8 is a guide for determining the appropriate confidential status of wells. Figure 1 provides well scenarios to assist in assigning confidentiality to XPL and DEV wells.

7.7.8.1 Confidentiality Considerations

The following are considerations when assigning confidentiality:

- The initial confidentiality assignment takes into account the presence or absence of the AER's official designated pool orders (formerly known as G orders) for wells under the *OGCR* but not for wells used to sequester captured CO_2.
- The most recent official pool order boundaries are on the AER website.
- Wells licensed under the *GRDR* and the *BMR* do not use pool orders and will be licensed as confidential.

Table 8. Well confidential status based on AER classification

AER classification	Well confidential status available at licensing phase
XPL, TH, OV, EX	(C) – CONFIDENTIAL
DEV, DSW, REN	(C) – CONFIDENTIAL if the well is outside the limits of AER-designated pools (formerly known as G orders) or inside the boundaries of an existing AER-designated confidential pool or is a well licensed under the *GRDR* or the *BMR*. (NC) – NONCONFIDENTIAL if the well terminates in or just below an AER-designated nonconfidential pool and is targeting that pool. If the well type and substance are production of crude bitumen in an oil sands area, the well is also nonconfidential. This confidentiality status only applies to wells licensed under the *OGCR*.
OTH	(C) – CONFIDENTIAL is only available for wells drilled under a carbon sequestration evaluation agreement. (NC) – NONCONFIDENTIAL for all disposal wells, including wells drilled under a carbon sequestration agreement.

AER classification	Well confidential status available at licensing phase
XPL, DEV, DSW, REN	(CB) – CONFIDENTIAL BELOW is assigned when one or more uphole zones penetrated by the well is inside an AER-designated nonconfidential pool. The "confidential below" formation name is the name of the deepest designated pool the well penetrates. This status will be assigned by the AER if the conditions described in section 12.150(2)(f) of the *OGCR* apply and after technical data has been reviewed. This status is not available during the licensing phase and is not applied to wells licensed under the *GRDR* or the *BMR*.

7.7.8.2 Process and Review Information

The following describes the process and review considerations for assigning confidentiality:

- Initial confidentiality statuses are to be selected by the applicant. "Confidential" or "nonconfidential" are the only valid selections available during the well licensing process. "Confidential" is the only valid selection for wells licensed under the *GRDR* or *BMR*. Wells licensed under the *OGCR* with a carbon sequestration evaluation agreement will be confidential for one year from the finished drilling date. Wells licensed under the *OGCR* with a carbon sequestration agreement are nonconfidential.
- Initial confidentiality selections are not reviewed by the AER before issuing a well licence.
- The AER strongly recommends that the licensee review its well licence to ensure the initial confidentiality status is accurate. If there is an error, the licensee may send a letter to the AER requesting a revision. Included in the AER's mandate is dissemination of information regarding the energy resources of Alberta; a request to revise an initial selection may be subject to review by the AER.
- The AER will review the initial confidentiality status shortly after a well licence is issued.
- In cases where the selection does not appear consistent with the regulations, the AER may issue a letter requesting information to support the confidentiality assignment. The letter will indicate that
  - the licensee has 30 days to file a submission package in support of the licensee's initial confidentiality selection, and
  - in the absence of a submission within 30 days, the AER will revise the initial confidentiality to the AER planned revision stated in the letter.
- Submission packages should include a covering letter stating the views of the licensee and any information in support of retaining the initial confidentiality selection.
- The AER will review submissions and issue a written decision. In some cases, meetings to exchange information may be necessary.

7.7.8.3 Ongoing Confidentiality Maintenance and the Application of the "Confidential Below" Status

Other than the confidentiality assigned to all geothermal or brine-hosted mineral wells, ongoing confidentiality maintenance may result in further revisions. After a well has been drilled, a licensee may request a revision to its confidentiality assignment based upon information gained as a result of drilling. If the revision meets the criteria in the regulations, the AER will revise the confidentiality. The AER will provide a written response to the request.

For each confidential well, the AER will initially assign an expected confidentiality release date of one year from its finished drilling date. However, the AER may scrutinize an *OGCR* well's confidentiality at any time, and if it meets the conditions for release in accordance with section 12.150 of the *OGCR* or section 15 of the *Oil Sands Conservation Rules*, its confidential status may be revised. The AER will notify the licensee of any planned confidentiality change, the licensee will have an opportunity to respond, and then a written decision will be issued. The AER will not notify licensees when confidentiality changes automatically—for example, when a confidential well becomes nonconfidential one year from its finished drilling date.

The AER may review wells that transition from CO_2 evaluation to active CO_2 sequestration within one year from the finished drilling date and change their status from confidential to nonconfidential.

Wells licensed under the *GRDR* or *BMR* will remain confidential for one year from the finished drilling date. When a well licence is converted from the *OGCR* to either the *GRDR* or B*MR*, it will remain confidential for one year from the date of the regulatory conversion approval. Confidentiality will apply only to information gathered on the well after conversion. Information on the public record before licence conversion will remain nonconfidential.

Wells licensed under the test hole classification described in section 2.030 of the *OGCR* are held confidential for five years as set out in section 12.150(7) of the *OGCR*.

7.7.9 Drill-Cutting Sample Requirements

Drill-cutting sample requirements for *OGCR*-licensed wells are determined using figure 1, figure 2, table 9, which describes the appropriate drill-cutting samples required based on a well's AER classification described in table 7.

23) The applicant must submit drill cuttings in 5 m intervals and in accordance with section 11.010 of the *OGCR*, section 80 of the *GRDR*, or section 87 of the *BMR* or apply for a variance. Drill-cutting sample requirements for geothermal wells are set out in section 3.2.1 of *Directive 089* and section 3.2 of *Directive 090* for mineral wells.

24) The applicant may request and obtain a drill-cutting sample variance before filing a well licence application provided it is disclosed as part of the application. The applicant may also request a drill-cutting sample variance as part of its well licence application or as part of an amendment to its well licence, as long as drilling has not yet started.

The AER may periodically identify areas where geological complexities dictate that additional samples should be taken. In those cases, the AER will notify the licensee of the revised requirements before drilling starts.

7.7.10 Groundwater Protection

25) Applicants must ensure that nonsaline groundwater is protected during drilling operations by

   a) meeting the requirements of section 6.080 of the *OGCR*, section 24 of the *GRDR*, or section 28 of the *BMR* and the requirements of *Directive 020* so that nonsaline aquifers (groundwater containing less than 4000 milligrams per litre [mg/l] total dissolved solids) will be covered by cementing surface casing, cementing the next casing string, or appropriate placement of open-hole abandonment plugs;

   b) meeting the requirements of section 19.1 of *Directive 036: Drilling Blowout Prevention Requirements and Procedures*, which prohibits the use of oil-based drilling fluids, or any other potentially toxic drilling additive when drilling above the base of groundwater protection; and

   c) referring to the Base of Groundwater Protection Query Tool to determine if a reference well, or depth below ground level, is available for determining the base of groundwater protection.

26) Baseline testing of water wells is mandatory for companies wanting to drill or recomplete a well to produce CBM above the base of groundwater protection (BGWP). The testing must gather background information on the water well's production capability and water quality. (Refer to section 8 in *Manual 012*.)

7.7.11 Surface Casing and Exemptions

Directive 008 sets out the requirements for determining surface casing depth for wells to be drilled and gives specifics on where surface casing is not required.

27) To obtain a surface casing variance in accordance with *Directive 008*, the applicant must either request a variance before filing the well licence application or apply for an in-application variance and include the following information, where applicable:

   a) Geological data:

      i) Identify all zones from surface to total depth.

ii) Identify gas potential in the hydrocarbon-bearing zones and provide an isopach map showing the extent of the productive zones.

iii) Identify any nonthermal enhanced recovery schemes within 1 km of the proposed well.

iv) Identify any thermal schemes within 1 km of the proposed well.

v) Identify the location of any water well within a 200 m radius of the proposed well.

b) Operations data:

i) Review offset wells within a 3 km area from surface to the terminating formation and provide the following for each well:

- well location (unique well identifier)
- zones and depths of severe lost circulation
- zones and depths of artesian water flows
- zones and depths of kicks and blowouts
- estimated unstimulated AOF rate
- H_2S content from surface to set casing depth
- formation pressures
- maximum pressure gradient of any formation to the terminating depth

c) For horizontal wells, indicate if intermediate casing will be set before drilling the horizontal section.

d) Provide the field kick rate.

28) In addition to the above, the applicant must provide a map that illustrates the area 3 km around the proposed well and shows

a) surface and bottomhole locations of the proposed well,

b) existing wells within 3 km of the proposed well that are drilled to the proposed terminating zone,

c) wells with hole problems,

d) AOF gas rates for existing wells,

e) proximity to thermal wells,

f) proximity to water bodies, and

g) if the proposed well is in an "established area" as defined in *Directive 008*.

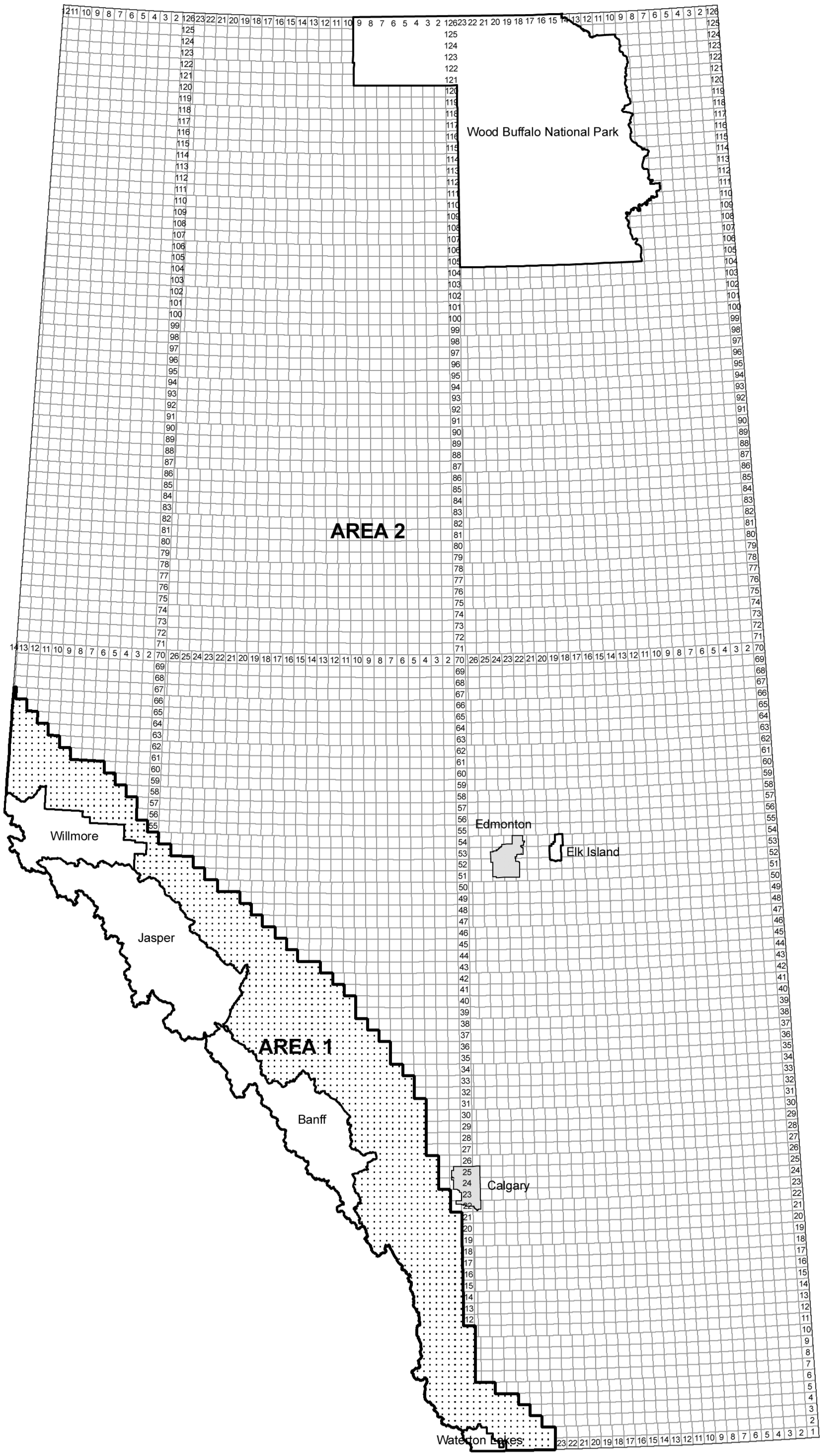

Figure 2. Drill-cutting sample requirements by area in Alberta

Table 9. Drill-cutting sample requirements or variance for wells licensed under the *OGCR*

AER classification	Well scenario	Drill-cutting sample requirement
Request for variance – All classifications (area 1 and area 2)	Any well scenario where a variance from the drilling cutting requirement is sought	See description in *Manual 012* to file a variance request
Area 1 (see figure 2)		
REN, TH		No drill-cutting samples required
XPL, EX	Well falls outside all AER-designated pools* from surface to total depth	Base of surface casing to total depth
	Well falls inside an AER-designated pool at total depth or well penetrates an AER-designated pool and is drilling to a deeper horizon	30 m above shallowest potential hydrocarbon-bearing horizon to total depth
DEV, DSW	Well meets one of the following exceptions: • The well type is production and well substance is crude bitumen • The well type of drilling operation is horizontal • The well projected total depth is less than 600 m	No drill-cutting samples required
	Well does not meet one of the exceptions described above and well falls outside all AER-designated pools* from surface to total depth	Base of surface casing to total depth
	Well does not meet one of the exceptions described above and well falls inside an AER-designated pool at total depth or well penetrates an AER-designated pool and is drilling to a deeper horizon	30 m above shallowest potential hydrocarbon-bearing horizon to total depth
OTH	A well drilled for water production, brine production, gas storage, or any other purpose not covered by other AER classifications	No drill-cutting samples required
	A well drilled for disposal of water, brine, acid gas, waste, or CO_2	30 m above the proposed disposal zone to base of disposal zone or total depth of the well
Area 2 (see figure 2)		
OV, REN, TH		No drill-cutting samples required
XPL, EX	Well falls outside all AER-designated pools from surface to total depth	30 m above shallowest potential hydrocarbon-bearing horizon to total depth
	Well falls inside an AER-designated pool at total depth	No drill-cutting samples required
	Well penetrates an AER-designated pool and is drilling to a deeper horizon	30 m above the first potential hydrocarbon-bearing horizon to be encountered after the well drills through the deepest AER-designated pool to total depth

AER classification	Well scenario	Drill-cutting sample requirement
DEV, DSW	Well meets one of the following exceptions: • The well type is production and well substance is crude bitumen • The well type of drilling operation is horizontal • The well projected total depth is less than 600 m	No drill-cutting samples required
	Well does not meet one of the exceptions described above and well falls outside all AER-designated pools* from surface to total depth	30 m above shallowest potential hydrocarbon-bearing horizon to total depth
	Well does not meet one of the exceptions described above and well falls inside an AER-designated pool at total depth	No drill-cutting samples required
	Well does not meet one of the exceptions described above and well penetrates an AER-designated pool* and is drilling to a deeper horizon	30 m above the first potential hydrocarbon-bearing horizon to be encountered after the well drills through the deepest AER-designated pool* to total depth
OTH	A well drilled for water production, brine production, gas storage, or any other purpose not covered by other AER classifications	No drill-cutting samples required
	A well drilled for disposal of water, brine, acid gas, waste, or CO_2	30 m above the proposed disposal zone to base of disposal zone or total depth of the well

* AER-designated pools formerly known as "G orders."

7.7.12 Right to Evaluate, Produce, or Operate

29) Before submitting a well licence application, the applicant must

a) be a working interest participant;

b) have the right to evaluate a well or the right to produce the oil, gas, crude bitumen, geothermal resources, or brine-hosted mineral resources from the well or the right to drill or operate the well for the authorized purpose;

c) for wells licensed to evaluate only, such as a well categorized as a "minerals evaluation" or as a disposal (CCS), there is an expectation that the applicant can demonstrate an authorization has been obtained for all activities in all targeted formations and the terminating formation. These wells are licensed to align with limited operational options set out in their respective mineral evaluation or carbon sequestration evaluation agreements.

d) for wells licensed under the *OGCR*, acquire the right to produce from the intended formation for the complete DSU; Part 4 of the *OGCR* gives requirements for normal DSUs and for special DSUs. Applicants need to be aware that fractional sections require a special DSU if the size of the fractional section differs by more than 5% from a normal DSU. The applicant must ensure that it acquires the rights for the entire DSU for the intended purpose of the well before submitting the application.

e) wells licensed under the *GRDR* and *BMR* do not rely on DSUs to establish subsurface spacing. The licensee must hold an appropriate agreement for rights at the bottomhole location of the wellbore and along the length of any horizontal portion that will be used to access geothermal or brine-hosted mineral resources;

f) further to e) above, licensees targeting geothermal or brine-hosted mineral resources should review requirements in *Directive 089* and *Directive 090* for information on subsurface setbacks.

g) if applicable, obtain permission from Alberta Energy to produce minerals under water bodies on Freehold mineral lands, as the Crown holds the mineral rights beneath water bodies; and

h) because normal DSUs do not include the road allowance, contact Alberta Energy if the bottomhole location of the well is in a road allowance.

7.7.12.1 Mineral Lease Continuation

Alberta Energy does not consider an application for a mineral lease continuation sufficient to demonstrate that an applicant has the rights for all of the intended purposes of the well.

30) Before submitting a well licence application with the AER, the applicant must receive a signed approval granting a mineral lease continuation from Alberta Energy.

7.7.12.2 Wellbore Rights for Abandoned Wells

Wellbore rights are separate and distinct from mineral rights and require separate approval before a well licence application can be filed.

31) Before filing a well licence application, the applicant must acquire the rights to the abandoned wellbore:

   a) For Freehold mineral rights, the applicant must obtain the abandoned wellbore rights from the licensee of record. If the applicant is unable to acquire an agreement from the licensee of record, the applicant must identify that in its application.

   b) For Crown mineral rights, if the mineral rights have not expired, the applicant must obtain the abandoned wellbore rights from the licensee of record; if the mineral rights have expired, the abandoned wellbore rights revert to the Crown. In this case, the applicant must obtain well re-entry approval from the Crown using the Request for Well Re-Entry Approval form available on the Alberta Energy website.

7.7.13 Setback Requirements

There are specific setback distances between wells containing H_2S gas and permanent dwellings, unrestricted country developments, urban centres, or public facilities.

32) The applicant must meet the applicable setback requirements in table 10based on the calculated H_2S release rate for the proposed well.

33) The level designation must be based on the suspended or producing H_2S release rate.

Table 10. Setback requirements for wells containing H_2S

Level	H_2S release rate (m^3/s)	Minimum distance
1	$\geq$0.01 to <0.3	0.1 km as stated in section 2.110 of the *OGCR*
2	$\geq$0.3 to <2.0	0.1 km to individual permanent dwellings and unrestricted country developments 0.5 km to urban centres or public facilities
3	$\geq$2.0 to <6.0	0.1 km to individual permanent dwellings up to 8 dwellings per quarter section 0.5 km to unrestricted country developments 1.5 km to urban centres or public facilities
4	$\geq$6.0	As specified by the AER, but not less than level 3

7.7.13.1 Water Bodies

A water body may contain or convey water continuously, intermittently, or seasonally and can be natural or man made.

For the purposes of *Directive 056*, a natural water body is defined as any location where water flows or is present, whether the flow or the presence of water is continuous, intermittent, or occurs only during a flood. This includes, but is not limited to, the bed and shore of a river, stream, lake, creek, lagoon, swamp, marsh, slough, muskeg, and other natural drainage, such as ephemeral draws, wetlands, riparian areas, floodplains, fens, bogs, coulees, and rills.

34) For the purposes of *Directive 056*, a man-made water body may include, but is not limited to, a canal, drainage ditch, reservoir, dugout, and other man-made surface feature. The well centre must be sited a minimum of 100 m from a water body.

35) Unless the AER permits otherwise, if the well centre is located on Freehold or Crown land but does not meet the 100 m setback requirement, the applicant must

   a) have a Crown disposition if the well centre is located on Crown land;

   b) maintain natural drainage if there is intermittent drainage or a spring or artesian flow across the well site or access road on Freehold and Crown land; and

   c) have acceptable measures in place to protect the water body during drilling and future production operations and mitigate the consequences of a spill on Freehold and Crown land.

Acceptable measures must include one or more of the following as required:

- site and berms constructed using impermeable materials
- synthetic liner
- vacuum truck
- absorption material
- enclosed systems with tankage
- textile mat

The AER expects the measures to comply with all relevant requirements of provincial and federal legislation and regulation (including *EPEA*, the *Water Act*, *Public Lands Act*, *Fisheries (Alberta) Act*, and the *Canadian Navigable Waters Act* and the regulations thereunder).

An applicant may request a variance if the applicant cannot meet the requirements above or wishes to propose alternative mitigative measures. The applicant must outline measures to protect the water body from contamination during drilling and future production operations and to mitigate the consequences of a spill.

36) If a water body will be disturbed by the well activity, the applicant must submit to the AER the approval received under the *Water Act*.

7.7.13.2 Surface Improvements

For the purposes of *Directive 056*, a surface improvement is defined as follows:

- a railway, pipeline, canal, or other right-of-way
- a road allowance and surveyed roadway
- a dwelling
- an industrial plant
- an aircraft runway or taxiway
- a building used for military purposes
- a permanent farm building
- a school
- a church

A surveyed road or road allowance is a surface improvement; however, specific setback requirements are discussed in section 7.7.13.3.

37) The well centre must be sited a minimum of 100 m from a surface improvement.

38) Unless the AER permits otherwise, the applicant must

    a) meet the 100 m setback requirement or

    b) acquire the consent of the surface improvement owner if the well centre does not meet the 100 m setback for a railway, pipeline, gas co-op, or other right-of-way.

39) For all other surface improvements, if the surface improvement owner consents to relaxation of the 100 m setback requirement, the applicant must disclose that in its application.

40) An applicant may request a variance from the AER if consent from the surface improvement owner cannot be acquired.

7.7.13.3 Surveyed Road or Road Allowance

A surveyed road or road allowance, whether developed or undeveloped, is considered a surface improvement but is subject to a 40 m setback. A lease or access road located on Crown or Freehold land or a private access road is not considered a surface improvement and is not subject to a setback.

The AER will consider a lesser distance if the applicant demonstrates that special circumstances exist and that the owner or administrator of the surface lands does not object.

41) You may request a relaxation from the 40 m setback requirement in your application.

42) The applicant is expected to consider other setback restrictions set out by Alberta Transportation and local authorities.

7.7.13.4 Airports

43) If the applicant proposes to drill a well within

    a) 5 km of a lighted (registered or unregistered) airstrip or aerodrome or

    b) 1.6 km of an unlighted (registered) airstrip or aerodrome,

    then before filing the well licence application, the applicant must advise Transport Canada, using the appropriate Transport Canada drilling rig clearance form.

44) If the applicant proposes to drill a well within a 1.6 km radius of a private, unregistered, and unlighted airstrip or aerodrome, the applicant must fulfil the participant involvement requirements in section 3.

7.7.13.5 Coal Mines

Sections 6.140 to 6.190 of the *OGCR*, sections 36 to 39 of the *GRDR*, and sections 43 to 46 of the *BMR* detail the requirements for a well proposed within 3 km of a working subsurface mine or within 400 m of an abandoned subsurface mine. If these requirements are applicable and the applicant is unable to meet the requirements, the applicant must provide an explanation of the reason the requirements cannot be met in the application.

If the applicant intends to drill through a bed or seam of coal, see section 3 for notification requirements.

7.7.14 AER Environmental Requirements

45) The applicant is expected to assess each well site and access road and to develop plans to conserve, reclaim, and mitigate the effects of its activities. These plans should include measures to contain any spills and prevent and control soil and water contamination, soil erosion, siltation of any drainage courses or water bodies, and slope instability.

46) Unless the AER permits otherwise, the applicant must meet the following requirements:

   a) For CBM wells completed above the base of groundwater protection, the applicant must meet the environment requirements listed in *Directive 035*.

   b) The applicant must have acceptable measures in place to protect the environment during drilling and future production operations and to mitigate the consequences of a spill:

      i) Acceptable measures for on-site containment must include one or more of the following as required:

         – site and berms constructed using impermeable materials

         – synthetic liner

         – vacuum truck

         – absorption material

         – enclosed systems with tankage

         – textile mat

      ii) The AER expects the measures to comply with all relevant requirements of provincial and federal legislation and regulation (including *EPEA*, the *Water Act*, *Public Lands Act*, *Fisheries (Alberta) Act*, and the *Canadian Navigable Waters Act* and the regulations thereunder).

      iii) Before constructing or preparing a well lease site or a well-site access road, the licensee is expected to meet the requirements and guidelines in all current and applicable AEPA informational letters.

   c) If there is intermittent drainage or a spring or artesian flow across the well site or access road, the applicant must maintain natural drainage.

d) If the proposed well site is within a caribou range, the applicant must ensure the requirements for development within a caribou range are met. See the AER website and consult with the AER for further information.

See section 8.6 if related to developments on the southern portion of the Eastern Slopes.

47) The applicant must request a variance if it cannot meet the requirements immediately above or if it proposes alternative mitigative measures to protect the environment.

An AER well licence does not relieve the applicant or licensee from meeting the legislative or regulatory requirements of the following:

- *EPEA* and *Regulation*
- other relevant acts, including provincial and federal legislation and regulation (including the *Water Act*, *Public Lands Act*, *Fisheries (Alberta) Act*, and the *Canadian Navigable Waters Act* and the regulations thereunder).

7.7.15 H_2S Release Rate Assessments

The AER requires the applicant to conduct an H_2S release rate assessment for each category C, D, or E well to ensure public safety when developing projects containing H_2S gas. The H_2S release rate assessment determines the minimum EPZ for the proposed project and dictates the minimum radius used in the applicant's participant involvement program.

48) If the producing or completion H_2S release rate is greater than the drilling release rate, the applicant must fulfil the participant involvement requirements applicable to the higher rate.

Pursuant to section 12.150(8.1) of the *OGCR*, section 95 of the *GRDR*, and section 103 of the *BMR*, the AER will normally consider interpretative data submitted in support of release rate assessments as confidential, provided that the data are indicated as confidential at the time of filing.

Test data used for H_2S release rate assessments are available in area summary format or individual well format from AER Information Services.

An applicant may file an H_2S release rate assessment with the AER before submitting a well licence application.

49) Before filing a well licence application, the applicant must also do the following:

a) The applicant must prepare an adequate H_2S release rate assessment that meets the outlined requirements.

b) The applicant must evaluate all formations up to and including the 15 m overhole interval and incorporate this information into the H_2S release rate assessment.

c) Upon request, the applicant must provide documentation to demonstrate that the H_2S release rate assessment was conducted before filing the well licence application.

d) The applicant must include related H_2S details for a well that may encounter H_2S gas. This information forms the basis for the applicant's participant involvement program for the proposed well project.

50) Each H_2S release rate assessment must consist of the following four components (described in more detail later in this section) but may include additional components as circumstances warrant:

a) a geological well prognosis with a comprehensive geological discussion

b) geological mapping

c) an engineering discussion

d) tabulated data

51) The applicant must support the H_2S release rate assessment with the proper documentation, as detailed in this section. This information must be available before filing a presubmission or well licence application and upon request. Its immediate availability is crucial in an emergency situation.

The AER expects that the documentation package will be prepared under the supervision of a member of the Association of Professional Engineers, Geologists, and Geophysicists of Alberta (APEGGA) or other technical designation.

7.7.15.1 Geological Discussion

52) The applicant must provide a geological well prognosis and a comprehensive geological discussion to address the hydrocarbon and H_2S potential of all formations encountered by the well. There are two basic cases for reviewing H_2S potential:

a) shallow wells – wells planned to reach total depth before the top of the Mannville Group (or equivalent zone)

b) deep wells – wells planned to be drilled deeper than the top of the Mannville Group

Shallow Wells

Reservoirs in shallow horizons may develop very low concentrations of H_2S gas during their operational life. In these cases, the calculated H_2S release rate may result in an emergency planning radius that is less than the total radius of the well-site lease; however, this needs to consider safety of personnel and the public.

53) The applicant must plan for the potential to encounter H_2S gas if gas analysis data in the public domain demonstrate that a reservoir originally not containing H_2S gas has evolved to gas containing H_2S.

Deep Wells

These wells have the potential to encounter H_2S gas horizons throughout the Mannville Group and deeper. However, H_2S gas zones may be encountered at shallower depths. Reservoirs in shallow zones may develop very low concentrations of H_2S gas during their operational life; one example is the Cardium Formation.

If a well encounters H_2S gas in the Mannville Group or deeper, the estimated H_2S release rate derived from the deeper zones usually overwhelms the small contribution from shallower zones. In this case, the contribution from shallower zones need not be considered in the cumulative H_2S assessment for the proposed well.

54) Should the assessment reveal that gas containing H_2S will not be encountered in formations or at depths greater than the top of the Mannville Group, the applicant must revisit the well prognosis and provide an H_2S release rate assessment for any shallow zones that have any concentrations of H_2S gas.

55) Should either proprietary data or data in the public domain on H_2S gas concentrations indicate that the H_2S release rate for shallow zones significantly affects the cumulative H_2S release rate for the proposed well, the applicant must include this information in the review.

Geological Considerations

56) The geological discussion must indicate the basis for the interpretation of the potential to encounter gas containing H_2S for each horizon (e.g., open-hole log interpretation, cross-sections, or pool isopachs derived from open-hole logs or seismic information, drillstem test recoveries, production, or any other appropriate information).

    The geological review must support the applicant's choice of data used in the H_2S release rate calculation. The CAPP document *H_2S Release Rate Assessment and Audit Forms* is one possible reference for the types of calculation adjustments or corrections that may be required.

57) The applicant is expected to consider the following examples (or other situations where they apply) of geological interpretations that may affect the H_2S release rate calculation for the proposed well:

    a) Wells near potentially productive reservoirs containing H_2S gas that are located along erosional edges (e.g., the Elkton member) should be evaluated for the potential for a reduced reservoir thickness beyond the limits of seismic resolution and for the potential to encounter productive outliers.

b) Different geological environments may lead to different potential reservoir trends. These trends sometimes exhibit a bias in H_2S concentration or AOF rates for wells completed in the different geological environments. This bias should be considered when reviewing data for geologically analogous pools:

   i) Because of the potential differences in AOF rates and H_2S concentrations, the applicant should identify and discard data obtained from a Nisku pinnacle reef reservoir in the West Pembina Basin if the target is the Nisku bank facies.

   ii) H_2S concentration and AOF rate data for wells in the Foothills area must be segregated by structural trend for evaluation since the geological analogue may be a pool on the same structural trend as the proposed well.

   iii) If multiple sands within a formation are potentially productive (e.g., Ellerslie #1 and #2 sandstone), the H_2S release rate must be adjusted to reflect this scenario.

c) If offsetting well data or seismic interpretation indicate that a substantially thickened reservoir is potentially present, this information must be used to determine the H_2S release rate.

7.7.15.2 Geological Mapping

The AER recommends that the applicant begin its geological assessment using a three-township by three-range map plot to examine the well penetration data appropriate for each zone that it identifies as its primary and secondary zones that may contain H_2S gas. The mapped data may assist in the determination of geological trends, the identification of applicable geologically analogous pools, and the estimation of the potential availability of H_2S concentration and AOF rate data for the geologically analogous area.

The results of this initial review may indicate that the map area should be expanded to identify the geological trend (e.g., reef platform or thrust sheet) or needs to be reduced due to a high well data density capable of providing sufficient data for review (e.g., oil pools with reduced spacing).

58) The applicant must submit geological maps for all formations that it identifies as its primary and secondary zones that may contain H_2S gas.

    For other potential H_2S zones the AER expects the applicant to implement the process outlined below in the “Tabulated Data” section. Mapping of these zones is not required.

59) The applicant must submit schematic dip-oriented cross-sections for all proposed wells located in the Foothills geological area based on existing well control or seismic information. The schematic cross-section must illustrate the relationship and the structural style of the prospective zones that may contain H_2S gas.

60) For map presentations relying on net pay or porosity interpretations, the applicant must provide the basis for the interpretation (e.g., gross pay, shale cutoffs, log porosity cutoffs, water saturation cutoffs) where applicable.

61) All map and schematic cross-section presentations must be completed before filing a well licence application.

The applicant may choose the map type that best illustrates its geological interpretation. The following are examples of appropriate map types:

- net pay isopach
- gross pay isopach
- structure contour
- show or bubble maps denoting test or production information
- porous thickness isopach
- isochron maps

62) Maps must show the following:

   a) township, range, meridian (sections where appropriate)

   b) map scale

   c) geologically analogous area or pool

   d) date prepared and company name

   e) existing well control and proposed well location

The applicant may choose the map annotations that best illustrate its geological interpretation. Map annotations should be applicable to the map type submitted. The following are some examples of annotations on a net pay isopach map:

- presence or absence of porosity (e.g., tight, shale)
- fluid content (e.g., water, gas, or oil) of the zone
- absence of the zone otherwise anticipated (e.g., eroded)

- estimate of net pay/pay:
  - where the zone is productive
  - at the proposed well location
  - by using contouring at the proposed location

The following are some examples of annotations on a structure contour map:

- presence or absence of porosity (e.g., tight, shale)
- fluid content (e.g., water, gas, or oil) of the zone
- absence of the zone otherwise anticipated (e.g., eroded)
- structural elevations and source (e.g., zone top or porosity top)
- structural contouring

7.7.15.3 Engineering Discussion

63) The applicant must provide an engineering assessment for each potentially productive zone that may contain H_2S gas that includes

  a) constraints that geological interpretation places on data gathering and review,

  b) corrections to H_2S concentration data, and

  c) corrections to AOF rate data.

64) Data must be from an analogous geological area or pool. Use of data from an arbitrary search area without consideration of the geological similarity of the pools is appropriate only when

  a) a review of the geological interpretation reveals that analogous geological pools exist within the search area or

  b) no demonstrated pattern or trend can be established and therefore the maximum H_2S concentration data and AOF rate data should be used.

65) The applicant must summarize the logic used to determine the release rate for each formation. The summary could be as simple as a statement indicating that the pay, pressure, and deviation for the proposed well and analogue well are comparable and, therefore, the highest values have been used; or it could be an in-depth account of the logic used for any data discounting or adjustments made.

Engineering Considerations

The CAPP document *H_2S Release Rate Assessment and Audit Forms* is one reference for many of the engineering formulas required to adjust the H_2S release rate. This document may also be used as a reference for the types of calculation adjustments or corrections that may be required as a result of the geological interpretation of the potential zones that may contain H_2S gas encountered by the proposed well.

Determining Release Rates

66) The applicant must determine three H_2S release rates:

   a) drilling release rate

   b) completion or servicing release rate

   c) suspended or producing release rate

67) To determine the cumulative H_2S release rate for the proposed well, the applicant must consider the development or exploratory nature of each zone that may contain H_2S gas.

   The maximum H_2S content and the maximum AOF rate are based on the information from the surrounding geological analogue pools or area completed in the same or similar zones.

The H_2S release rate for each potential zone that may contain H_2S gas is determined by multiplying the maximum H_2S content and AOF rate as determined by the geological and engineering review of the available data. The paired data points need not be from the same well.

The drilling release rate for each intermediate hole and main hole is the sum of the release rates from each zone that will be open to the wellbore during the drilling operations.

To calculate the release rate for each zone that may be encountered, AOF rate data may be adjusted to reflect the different flow scenarios appropriate for each zone. If preferred, post-stimulation data, without adjustment for tubing or casing friction loss, may be used for all scenarios.

The applicant may calculate the maximum drilling release rate by totalling the unstimulated release rate for each formation. The discounting of flow data due to stimulation is not appropriate. Post-stimulation data may be adjusted to reflect a zero skin.

The completion or servicing release rate for the targeted formation relies on post-stimulation AOF data. These AOF data may be adjusted for the effects of friction loss using the configuration of the casing cemented in the hole.

The suspended or producing release rate also relies on post-stimulation AOF data and may include an adjustment calculation for flow to surface to account for tubing friction loss. The suspended or producing release rate is used to determine the level classification and the minimum distance or setback requirement for the proposed well (see table 10). Communication of this minimum setback distance is a key component of the applicant's participant involvement plan for the proposed well (see section 3).

68) A summary of the engineering review, identifying adjustments, corrections, and discounted data as appropriate, must be included with presubmission materials or in the H_2S release rate assessment package and must be made available to the AER upon request.

Release Rate Scenarios

69) Each proposed well must be evaluated with its unique circumstances in mind. These calculations must be documented and included with an H_2S release rate presubmission request and made available to the AER upon request.

The following list gives common release rate calculation corrections and comments on appropriate methodology and is not exhaustive:

- H_2S samples – H_2S samples must not be discounted simply because the sample point source is listed as "other." A review of the gas analysis is required to determine if the sample point is reasonable for use. If the review indicates that the sample point is not representative (e.g., it is a second-stage separator sample source for a gas well release rate), it may be discounted and an annotated analysis describing the reason for discounting must be included.
- Potential for both gas and oil production – If a formation has potential for both gas and oil production, the applicant must calculate both release rates and use the higher value:
  - H_2S release rates for oil should be calculated using the maximum gas rate from inflow performance relationship (IPR) tests and the maximum H_2S concentration from solution gas samples.
  - For H_2S release rates based on analogous oil wells, the oil rate from the IPR test and the gas-oil ratio measured during that test should be used to calculate the maximum gas rate for analogous wells. Combining a maximum IPR rate with a maximum gas-oil ratio that is not from the same test may result in an unreasonable release rate and is therefore not recommended.
- Extended AOF data – When both extended and stabilized AOF rates are reported, the extended AOF must be used for release rate purposes. A production rate for a well that is higher than the AOF for the same well is often an indication that the reported AOF might be the stabilized value. In this case, a review of the AOF test is required.
- Single-point AOF – If the "n" value used for a single-point AOF test is not 1.0, a calculated AOF assuming an "n" of 1.0 must be used, unless a review is undertaken to

determine a more appropriate value. A summary of this review must be included with a presubmission and made available to the AER upon request.

- Potential producing zones – If the estimated potential pay for the primary and secondary zones that the applicant identifies are estimated to be higher than the pay for the analogue wells used for each zone, the AOF rates must be adjusted for each zone affected.
- Multiple sands – If multiple sands within a formation are potentially productive (e.g., Ellerslie #1 and #2 sandstone), the release rate must be adjusted to reflect this scenario. This can be done by multiplying the maximum release rate calculated for a single sand by the number of potential sands or by totalling the pay estimated for each of the sands and adjusting for the pay of the analogue well. If significant differences in performances can be documented between sands, a release rate based on individual sands is acceptable.
- AOF pressure – If the pressure reported for the AOF from an analogue well is lower than the pressure expected at the proposed location, an adjustment of the AOF to the expected pressure is required. Due to the potential impact an adjustment can have on the revised AOF, the viscosity of the gas at each pressure is required to be used in the formula. If a well has multiple AOF tests performed at declining reservoir pressure, only those performed at close to the initial pressure should be used unless some type of stimulation has been performed since the first tests.
- Pool development – In a pool development scenario, it is reasonable to use the existing wells in the pool as analogues. If the proposed well is the second well in the pool, the H_2S concentration from the first well in the pool may be used; however, because of the variance of AOFs within pools, the flow potential should be estimated from all analogous pools in the area. If the pool is under any type of scheme (e.g., acid gas disposal or injection), the release rate must address the current pool characteristics. If the proposed well will penetrate a pressure depleted pool, the AOF may be adjusted to reflect the current expected reservoir pressure.
- Commingled pools – Commingled pools present additional complexity when reviewing the release rate. Analogous wells must not be discounted because the pool name indicates it is commingled. In many instances, test data are obtained before commingling. Although the pools may have approval for commingling, only a few wells in the pools may actually be commingled. A review of the test or completion data is necessary to determine the actual formation tested and the appropriate data for the formations in question.

7.7.15.4 Tabulated Data

70) The applicant must provide the results of H_2S concentration and AOF rate reviews in a tabular format. The CAPP document *H_2S Release Rate Assessment and Audit Forms* provides examples. Regardless of the table format used, the basic data elements as described in the CAPP tables must be provided, along with an indication as to whether the AOF rate data are from a single or multipoint test.

71) The applicant must select a minimum of five H_2S gas analyses and five AOF data points that are representative of each potential zone that may contain H_2S gas. Data points are representative if they are from a geologically analogous area or pool and are not discounted for technical reasons. In situations where multiple data points exist for the same well, only one value is considered representative. If any of the five data points encounter an AER-defined pool, the applicant must assess all of the wells within the pool boundary.

    If higher values are discounted, the applicant must support the decision in the geological or engineering discussion.

7.7.16 Working Interest Participants

72) The applicant must be a working interest participant to apply for or hold a well licence.

7.7.17 Additional Application Requirements

73) If the applicant has obtained a zero-flaring agreement (see *Directive 060*), a copy must be retained by the applicant and submitted if requested.

74) The AER does not require applicants to acquire road-use agreements before submitting its application; however, they must be in place before construction.

75) Applicants must meet the requirements in section 8.3 when planning sour gas activity where residents are located within the EPZ.

8 Additional Application Requirements (Special Circumstances)

8.1 Overview

This section sets out application-related requirements that address specific locations or circumstances. It is included to avoid creating multiple directives on specific matters that primarily relate to the applications process.

8.2 Battle Lake Area Application Requirements

8.2.1 Background

Battle Lake is a unique environment in that it remains essentially a wilderness lake convenient to major population centres (one hour from Edmonton and Red Deer and two-and-a-half hours from Calgary). In 1974, the County of Wetaskiwin commissioned a study about Battle Lake and gave the lake a protected status, with overwhelming support from area residents. That status was later modified by the county's general plan and a watershed protection district was formed instead. The provincial government also recognized the merit of protecting the area by creating the Mount Butte and South Battle Lake Natural areas, which now protect about one-third of the shoreline and riparian zones and some upland habitat.

Subsequent to *Decision 2005-129: Ketch Resources Ltd.; Review of Well Licence No. 0313083 and Application for Associated Battery and Pipeline, Pembina Field*, the AER engaged Battle Lake area stakeholders in a pilot project to address upstream oil and gas development issues. After a detailed review, the area stakeholders recommended, and the AER concurred, that further disturbance by oil and gas development close to Battle Lake and surface water features in the contributing watershed (designated as the Tier 1 area) should be avoided where practical. In particular, lands within the Tier 1 area are closely linked to Battle Lake. Should spills or leaks occur, contaminants would quickly enter Battle Lake, giving limited opportunity to implement effective emergency measures. The Tier 1 areas include bald eagle nesting sites, fish spawning grounds, unique vegetation communities (fern meadows), and natural upland wildlife habitat areas. Battle Lake community residents hold very strong views that further development within Tier 1 areas is not acceptable.

As a result, the AER has determined that licence applications for oil and gas facilities located in the designated Tier 1 area will be considered through the *Directive 056* application licensing process. The designated Tier 1 area as of May 1, 2007, includes Townships 45 and 46, Ranges 2 and 3, West of the 5th Meridian, and is illustrated in figure 3. Note that the current mapping of the area may not have identified and designated all water features, notably springs in the area. It is intended that water features in the watershed be protected. Therefore, potential development sites need to be assessed to verify whether unmapped water features are present. If unmapped water features are identified, these areas are to be protected consistent with Tier 1 practices.

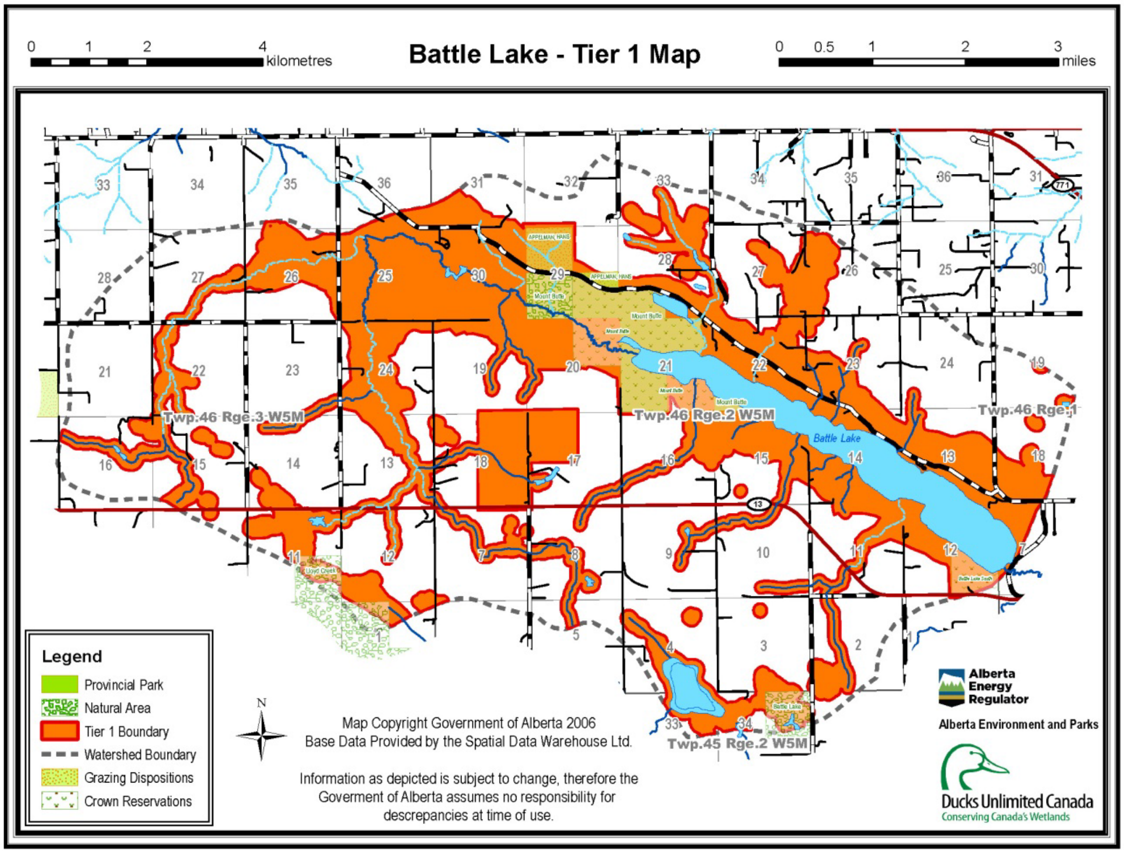

Figure 3. Battle Lake Tier 1

8.2.2 Battle Lake Tier 1 Area Definition

The Tier 1 area is defined as surface lands within

- 100 m of water features that feed into Battle Lake (water features for the purpose of this criterion include permanent and recurring streams, springs, and wetlands [fens, bogs, muskeg, marshes]; these include water bodies and wetlands as defined by the more stringent or comprehensive designations in the *Water Act* and the *Alberta Wetland Policy*);
- 100 m of the 900 m (2950 foot) elevation contour along the shoreline of Battle Lake (top of the escarpments that parallel the lake); and
- the Mount Butte natural area, County natural areas, South Battle Lake Natural Area, and remaining undisturbed natural areas on public lands.

8.2.3 Application Requirements for the Tier 1 Area

1) Proponents must investigate alternative approaches for oil and gas development and, where feasible, are expected to select those that avoid further disturbance of Tier 1 areas.

2) If development within Tier 1 area is viewed as unavoidable, proponents must

   a) assess opportunities to use existing facilities, road access, pipeline rights-of-way, and other pre-existing disturbances and to minimize incremental disturbances in Tier 1 areas;

   b) ensure that well, production battery, compressor, and gas plant sites located in Tier 1 have appropriate mitigative measures to prevent fluid spills and contaminated runoff from entering wetlands, streams, or the lake during construction and operational phases (e.g., runoff containment berms and retention ponds, catch-pans, or devices for equipment seal leaks); and

   c) incorporate mitigative measures to maintain the integrity of pipelines and provide for early detection of and response to leaks for new hydrocarbon liquid and produced water pipelines traversing Tier 1 lands.

3) Proponents must conduct a preapplication on-site assessment to determine site, pipeline, and road locations that will

   a) avoid sensitive habitats that may include bald eagle nesting sites, fern meadow sites, and other unique ecological features that may be identified;

   b) identify and avoid steep slopes where construction could require significant surface disturbance or aggravate erosion problems; and

   c) avoid disturbance of springs, streams, and wetlands.

   A primary purpose of the site assessment is to verify whether unmapped water features are present. If unmapped water features are identified, these areas are to be protected.

The AER encourages applicants to

- participate in the Battle Lake Watershed Synergy Group,
- review their plans and explain their rationale for their proposed development in Tier 1 areas at a regular meeting of the synergy group, and
- consult with the Battle Lake Preservation Society and seek its advice on locations and mitigative measures for new development in Tier 1 areas.

4) In addition to the required documentation, all *Directive 056* applications for development in the Tier 1 area must be accompanied with justification that includes the following information:

   a) a cover letter that identifies that the proposed development is within the Battle Lake Tier 1 area

   b) an explanation of the alternatives involving development outside Tier 1 areas that have been investigated and an explanation of why these are not technically feasible; the alternatives are to be compared with the application case in terms of potential land disturbance and other watershed impacts, impacts on the public, resource recovery, and feasibility

   c) a description of the proposed site that describes existing cover, habitat features, and presence of surface water features (springs, streams, and wetlands)

   d) an explanation of how existing facilities and disturbances have been incorporated into the project

   e) an explanation of mitigation measures the proponent will undertake to prevent contamination of surface water bodies from leaks and spills

   f) a description of any feedback on the proposed development as a result of discussions with the Battle Lake Watershed Synergy Group and the Battle Lake Preservation Society

The AER expects that any new disturbance will be limited to the minimum area feasible and that cleanup, regrading, and establishment of natural cover similar to predisturbance conditions on unused portions of rights-of-way and lease sites will occur as soon as possible following construction.

8.2.4 Non-Tier 1 Areas

The Battle Lake pilot project also addressed facility application considerations for other parts of the watershed, including the adoption of recommended practices for areas not designated as Tier 1. Proposed surface facility development within Battle Lake Tier 2 (undisturbed and forested lands) and Tier 3 (lands disturbed by agricultural, residential, or other industrial development) areas must meet all *Directive 056* requirements.

8.3 Sour Gas Planning and Proliferation Application Requirements

5) Effective June 30, 2008, all applicants must follow the *Recommended Practices for Sour Gas Development Planning and Proliferation Assessment* (*Recommended Practices;* available on the *Directive 056* landing page under Supplemental Information) when proposing sour gas

development (i.e., facilities, pipelines, and wells) in areas where residents are located within the EPZ.

8.3.1 Background

In December 2000, the Provincial Advisory Committee on Public Safety and Sour Gas produced a final report that contained 87 recommendations for addressing public safety and sour gas. In recommendations 7, 32, and 33, the committee noted that a greater effort was required to reduce the proliferation of sour facilities near people and that more information regarding future development plans should be provided to people near sour gas developments as part of the AER's application and licensing process. In response to these recommendations, an oversight committee consisting of public, industry, and regulatory participants monitored sour gas development applications over a two-year trial period to determine if the *Recommended Practices* would be effective in responding to recommendations 7, 32, and 33.

In 2007 the oversight committee provided its report. The report noted that when the *Recommended Practices* were followed, the effect was consistent with the intent of recommendations 7, 32, and 33 and that the *Recommended Practices* were an effective approach to developing and maintaining good relations with the public.

However, because industry participation during the two-year trial was less than expected, the oversight committee subsequently recommended that a requirement to follow the *Recommended Practices* was necessary to meet recommendations 7, 32, and 33.

8.3.2 Application Requirements for Sour Gas Development

Applicants must meet the following additional application requirements when preparing applications for sour gas development near people.

6) Before submitting an application, the applicant must follow the *Recommended Practices* when planning sour gas development in areas where there will be residents located within the calculated EPZ. At a minimum, the applicant must

   a) conduct an assessment of any existing facility or pipeline to determine if it can be used;

   b) expand the project-specific information package requirements in section 3 to include

      - a detailed description of the full project, including future wells, pipelines, and facilities,
      - the results of the applicant's assessment for the use of existing infrastructure,

- a map that illustrates the assessment area, including proposed wells, pipelines, and/or facilities, existing land use (e.g., roads, residences), and existing infrastructure investigated, and
- the anticipated timing for the project from the licensing stage through to production operations; and

c) meet all participant involvement requirements set out in section 3.

7) An applicant that is required to conduct an assessment of the existing infrastructure must

a) review all existing sour gas facilities and sour gas pipelines within a 15 km radius of the proposed facility;

b) evaluate the feasibility of upgrading an existing facility and of forging commercial partnerships with existing licensees (for example, contact area operators for information required to conduct the assessment: operating pressure, available capacity, H_2S limitations, future production potential for the area); and

c) document the evaluation for application and audit purposes.

8.3.3 Addressing Concerns and Objections

If a concern or objection has been received and remains unresolved, the applicant is subject to the following additional requirements specific to sour gas planning and development.

8) If there are residents located in the calculated EPZ and there are unresolved concerns or objections, the applicant must

a) submit an application that includes documentation to demonstrate that the requirements of section 8.3.2 were met and

b) consider preparing an area development plan as set out in the *Recommended Practices*.

If an area development plan has been developed, see section 3 for further requirements.

In some circumstances the AER may request that an area development plan be prepared in accordance with the *Recommended Practices* for distribution before submitting or during the processing of the application.

9) An applicant proposing sour gas development where there are residents located in the EPZ and about which unresolved concerns or objections exist may be required to submit all applications associated with the proposed sour gas project (i.e., wells, facilities, and pipelines) at the AER's request.

8.3.4 Application Submission

10) If there are no unresolved concerns or objections, the applicant must confirm that none exist and the application meets the requirements of the *Recommended Practices*. Applicants are not required to attach the documentation that demonstrates they met *Recommended Practices* but must retain the documentation for audit purposes.

11) In those cases where there are one or more surface developments within the EPZ but none of those surface developments is a residence, the *Recommended Practices* would not apply. Applicants must identify the type of surface developments and confirm that section 8.3 does not apply.

8.3.5 Audit

The audit review process will ensure that the sour gas development requirements summarized in section 8.3.2 were fulfilled before submitting the application.

8.4 Peace River Area Application Requirements

8.4.1 Background

In January 2014, a panel of AER hearing commissioners conducted an inquiry on odours and emissions from heavy oil operations in the Peace River area of Alberta. On March 31, 2014, the panel released *Decision 2014 ABAER 005: Report of Recommendations on Odours and Emissions in the Peace River Area*. The AER accepted all of the panel's recommendations within its jurisdiction. Among the commitments that the AER made in its response to the report were to require

- existing heavy oil and bitumen operations in the Peace River area to capture and flare, incinerate, or conserve all casing gas and tank-top gas and
- new heavy oil and bitumen operations in the Peace River area to capture and flare, incinerate, or conserve all casing gas and tank-top gas effective May 15, 2014.

Licensees of existing operations and applicants for new developments in the Peace River area will need to demonstrate that their projects meet these requirements when submitting facility licence applications under *Directive 056*.

8.4.2 Peace River Area Definition

The Peace River area covers the Three Creeks, Reno, Seal Lake, and Walrus areas (see figure 4).

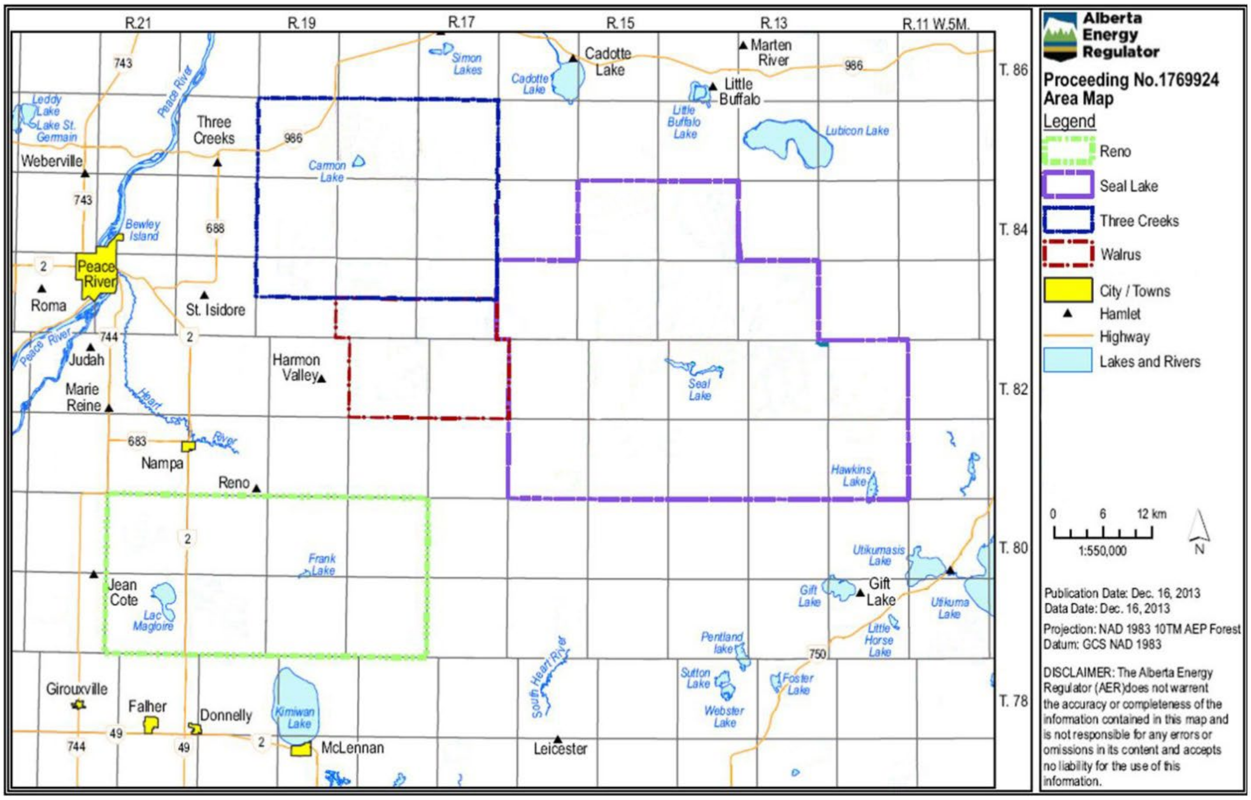

Figure 4. Peace River area

8.4.3 Application Requirements for the Peace River Area

12) Effective May 15, 2014, applicants for new heavy oil and bitumen operations in the Peace River area must submit documentation with their facility licence application that includes

a) a PFD that shows that all casing gas and tank-top gas will be captured and flared, incinerated, or conserved;

b) confirmation that there is no total continuous venting;

c) details on any compressor associated with the vapour recovery unit regardless of its size; and

d) any other information requested by the AER.

Heavy oil and bitumen operations in the Peace River area that are exempt from *Directive 056* licensing must still meet the Peace River area requirements in *Directive 060* for the capture and flaring, incinerating, or conserving of all casing gas and tank-top gas.

8.5 Application Requirements for Activities Within the Boundary of a Regional Plan

The AER is legally obligated to act in compliance with any approved regional plans under the *Alberta Land Stewardship Act*. To ensure this compliance, the AER requires any applicant seeking approval for an activity that would be located within the boundary of an approved regional plan to meet the requirements below.

13) For an activity to be located within the boundary of an approved regional plan, the applicant must assess

    a) whether the activity would also be located within the boundaries of a designated conservation area, a provincial park, a provincial recreation area, or public land area for recreation and tourism and, if so, whether the mineral rights associated with the activity are subject to cancellation;

    b) whether the activity is consistent with the land uses established in the applicable regional plan or with any of the outcomes, objectives, and strategies in that same plan; and

    c) how the activity is consistent and complies with any regional trigger or limit established under the management frameworks detailed under the applicable regional plan or any notices issued in response to the exceedance of a regional trigger or limit.

14) The applicant must retain sufficient information for requirement 13 at all times and provide it on request unless otherwise indicated below.

15) The applicant must submit the information from requirement 13 if the proposed activity to be located within the boundary of an approved regional plan

    a) is also within the boundaries of a designated conservation area, a provincial park, a provincial recreation area, or a public land area for recreation and tourism;

    b) is inconsistent with the land uses established in the applicable regional plan or any of the outcomes, objectives, and strategies in that same plan;

    c) may result in the exceedance of a trigger or limit or contravene a notice issued in response to an exceedance of a trigger or limit; or

    d) is "incidental" to previously approved and existing activities.

16) If the applicant believes that its proposed activity is permitted under the applicable regional plan because it is incidental to previously approved and existing activities, the applicant must provide information to support its position.

The AER has no authority to waive compliance with or vary any restriction, limitation, or requirement regarding a land area or land use under a regional plan. Applicants that wish to seek this type of relief must apply directly to Alberta's Land Use Secretariat established under the

Alberta Land Stewardship Act. The stewardship minister may, on application and by order, vary the requirements of a regional plan.

8.6 Energy Resource Development in the Eastern Slopes (Southern Portion)

In 1993, the AER issued *IL 93-09: Oil and Gas Developments Eastern Slopes (Southern Portion)*, setting guidelines and expectations for oil and gas development in this region. These guidelines and expectations apply equally to any energy resource developments in this region.

17) If the energy resource development is located within the southern portion of the Eastern Slopes, the applicant must meet the general expectations described in *IL 93-09* by

    a) preparing development plans beyond the initial exploration stage, taking into consideration current stages such as

        i) pool or other energy resource delineation (initial),

        ii) pool or other energy resource delineation (subsequent), and

        iii) pool or other energy resource development, and

    b) developing environmental assessments.

18) If requested by the AER, the licensee must submit all environmental documentation outlined in *IL 93-09*.

Appendix 1 Definitions

abandoned well	A well that has been drilled, abandoned, cut, and capped at surface.
abandonment	The permanent dismantlement of a well, pipeline, or facility in the manner prescribed by the regulations; includes any measures required to ensure that the well, pipeline, or facility is left in a permanently safe and secure condition.
acid gas	Gas that is separated in the treating of solution or nonassociated gas that contains hydrogen sulphide (H_2S), totally reduced sulphur compounds, or carbon dioxide (CO_2).
additional review	An application is electronically selected for a manual review of specific components. Additional review occurs if the if the applicant cannot meet requirements; chooses to apply for a regulatory relaxation; all participant involvement requirements have not been met, outstanding concerns or objections exist; proposes to implement new technology; or the application is designated for additional review (e.g., a new category C or D plant, any category E application).
applicant/licensee	The company responsible for the accuracy and completeness of the application and all supporting information. Upon licence approval, the applicant becomes the licensee and bears responsibility for the construction and safe operation of the facility, pipeline, or well. The licensee is also responsible for the decommissioning, abandonment, and reclamation of the facility, pipeline, or well.
baseline review	An applicant is electronically identified as meeting all requirements and will proceed without manual review.
battery	*See* gas battery *and* oil/bitumen battery.
bitumen	Bitumen may be defined by specific gravity or API units or by the well's location within the designated oil sands areas.
blending	The combination of natural gas streams with different H_2S contents for the purpose of maintaining a lower H_2S content in the blended stream.
blowout	A well where there is an unintended flow of wellbore fluids (oil, gas, water, or other substance) at surface that cannot be controlled by existing wellhead or blowout prevention equipment, or a well that is flowing from one formation to other formations (underground blowout) that cannot be controlled by increasing the fluid density. Control can only be regained by installing additional or replacing existing surface equipment to allow shut-in or to permit the circulation of control fluids, or by drilling a relief well.
brine-hosted mineral resources	As defined in the *Brine-Hosted Mineral Resource Development Rules*.

coalbed methane gas	Natural gas that is found in coal.
coalbed methane well	Any well intended to produce or producing coalbed methane.
compressor station/site	Service equipment intended to maintain or increase the flowing pressure of the gas that it receives from a well, battery, or gathering system before delivery to market or other disposition.
condensate	A hydrocarbon liquid recovered either from a natural gas well or at some point in the field handling system consisting primarily of pentane and heavier hydrocarbons.
construction (facilities)	When any equipment associated with a licence for the facility is brought to the site or when a ground disturbance required for the facility equipment is initiated.
consultant	A person or corporation authorized by an applicant to prepare its application. The applicant is still responsible for the accuracy and completeness of the application if filed on its behalf by a consultant.
confirmation of nonobjection	A statement made by a person that confirms there is no objection to the AER granting a licence for the proposed energy development.
critical sour well	The AER designation of a well for drilling purposes with an H_2S release rate greater than or equal to 2.0 m^3/second or other wells with a lesser H_2S release rate in close proximity to an urban centre.
Crown disposition	The administrative and operating conditions assigned for use of public lands in the form of a lease, licence, permit, or letter of authority; administered by the AER.
Crown disposition holder	A person or party that has been assigned use of public lands (e.g., lease, licence, or permit) issued under the provisions of the *Public Lands Act*.
Crown land	Provincial Crown land administered under the *Public Lands Act*. (Federal land falls under the definition of *Freehold land*.)
custom treating plant	A system or arrangement of tanks and other surface equipment receiving oil/water emulsion exclusively by truck for separation before delivery to market or other disposition.
dehydrator	Equipment designed to remove water from raw gas.
design capacity	The maximum capable throughput of volumes based on the engineering design of all on-site equipment associated with the facility.
directionally drilled well	A well drilled on an angle from a surface location to a subsurface location some lateral distance away from the surface location of the well.

drilling spacing unit	The drilling spacing unit (DSU) for a hydrocarbon well is • the surface area of the DSU and the subsurface vertically beneath that area or, • where the DSU is prescribed with respect to a specified pool or geological formation, member, or zone, the pool, geological formation, member, or zone vertically beneath that area. The normal DSU for an oil well is one quarter section. The normal DSU for a gas well is one section. A DSU does not include the area of a road allowance.
emergency planning zone	A geographic area surrounding a well, pipeline, or facility containing hazardous product that requires specific emergency response planning by the licensee.
emergency response plan	A comprehensive plan to protect the public, including criteria for assessing an emergency situation and procedures for mobilizing response personnel and agencies and establishing communications and coordination.
emulsion	A combination of two immiscible liquids or liquids that do not mix together under normal conditions.
energy development	Any construction or operation of wells, pipelines, or facilities to extract or deliver energy resources under an energy resource enactment, as defined by the *Responsible Energy Development Act*.
expectations	Recommended best practices or guidelines.
environment	All components of the earth, including air, land, and water; all layers of the atmosphere; all organic and inorganic matter and living organisms; and interacting natural systems.
facility	Any building, structure, installation, equipment, or appurtenance (excluding wells and pipelines) over which the AER has jurisdiction and that is connected to or associated with the recovery, development, production, handling, processing, treatment, or disposal of hydrocarbon-based resources or any associated substances or wastes.
flame-type equipment	Any electric or fired heating equipment using an open flame, electric arc, or element—includes a space heater, torch, heated process vessel, boiler, electric arc, open flame welder, and open element electric heater or appliance.
Freehold land	Freehold land is any land in Alberta not administered under the *Public Lands Act*, including public land administered under other acts or agreements such as federal lands and the land administered by the provincial Special Areas Board.

gas battery	A system or arrangement of tanks and other surface equipment (including interconnecting piping) that receives the effluent from one or more wells that might provide measurement and separation, compression, dehydration, dew point control, H_2S scavenger where <0.1 t/d of sulphur is being treated, line heater or other gas handling functions before the delivery to market or other disposition. This does not include gas processing equipment that recovers more than 2 m^3/d of liquids or processes more than 0.1 t/d of sulphur.
gas fractionating plant	An arrangement of equipment to reprocess a natural gas liquid inlet for the extraction of liquids.
gas processing	The changing of the composition of raw natural gas either at processing facilities at the gas field or at straddle plants located on pipeline systems.
gas processing plant	A system or arrangement of equipment used for the extraction of hydrogen sulphide, helium, ethane, natural gas liquids, or other substances from raw gas; does not include a wellhead separator, treater, dehydrator, or production facility that recovers <2 m^3/day of hydrocarbon liquids without using a liquid extraction process (e.g., refrigeration, desiccant). In addition, does not include an arrangement of equipment that removes small amounts of sulphur (<0.1 t/d) through the use of nonregenerative scavenging chemicals that generate no hydrogen sulphide or sulphur dioxide.
gas well	A well that produces primarily gas from a pool or portion of a pool wherein the hydrocarbon system is gaseous or exhibits a dew point reduction of pressure, or any well so designated by the AER.
geothermal resource	As defined in the *Geothermal Resource Development Act*.
hand delivered	Delivering documents directly to a participant at their place of residence or place of business.
high-vapour-pressure (HVP) pipeline	A pipeline system conveying hydrocarbons or hydrocarbon mixtures in the liquid or quasi-liquid state with a vapour pressure greater than 110 kPa absolute at 38°C, as determined using the Reid method (see ASTM D323). Some examples are liquid ethane, ethylene, propane, butanes, and pentanes plus.
hydrogen sulphide (H_2S)	A naturally occurring gas found in a variety of geological formations and also formed by the natural decomposition of organic matter in the absence of oxygen. H_2S is colourless, has a molecular weight that is heavier than air, and is extremely toxic. In small concentrations it has a rotten egg smell and causes eye and throat irritation.
injection/disposal facility	A system or arrangement of surface equipment associated with the injection or disposal of any substance through one or more wells for the purpose of water disposal or enhanced oil recovery.

landowner	The person in whose name a certificate of title has been issued pursuant to the *Land Titles Act* or, if no certificate of title has been issued, the Crown or other body administering the land. In the case of Métis land, the person registered in the Métis Settlements Land Registry as owner of the Métis title pursuant to the *Métis Settlements Land Registry Regulation*.
large diameter/high pressure hydrocarbon pipeline	A hydrocarbon pipeline with both an outside diameter equal to or greater than 323.9 mm and an MOP equal to or greater than 3475 kPa.
level designation	A designation that stipulates different separation or setback distances for wells, pipelines, and facilities for land use and public safety.
licensee	The holder of a facility, pipeline, or well licence according to the records of the AER—includes a trustee or receiver-manager of property of a licensee (also see Applicant).
line heater	Equipment installed at either the well-site lease or along a pipeline right-of-way to prevent the formation of gas hydrates.
local authority	Council of a city, town, village, or municipal district, or in the case of an improvement district or special area, the Minister of Municipal Affairs, the council of a settlement under the *Métis Settlements Act*, or the band council of a First Nations reserve.
location exception (LE) code	A code that identifies cases when there is more than one wellbore or facility on the smallest land area described by the Dominion Land Survey system.
lost circulation	The loss of drilling fluids from the wellbore into permeable formations penetrated during drilling of the well.
mineral brine	As defined in the *Brine-Hosted Mineral Resource Development Rules*.
minimum information requirements	The project-specific details that an applicant must provide to all parties in accordance with the participant involvement guidelines.
multiwell facility	A battery (oil, gas, or bitumen) or satellite handling the production from multiple zones being produced in segregation from one wellbore; inlets for more than one well are located and being produced at a battery or satellite at one surface location; multiple single-well batteries or satellites are operated within one surface lease.
nonobjection	The party has been personally consulted or notified of the project, has fully understood the details, has no outstanding concerns or objections, and does not oppose the AER issuing a licence for the proposed energy development.

nonroutine	An application is nonroutine if the applicant cannot meet requirements or chooses to apply for a regulatory relaxation; all participant involvement requirements have not been met, outstanding concerns or objections exist, the applicant proposes to implement new technology, the application is designated nonroutine (i.e., a new category C or D plant, any category E application).
notification	The distribution of project-specific information to participants.
occupant	A person other than the owner who is in actual possession of land; a person who is shown on a certificate of title or by contracts as having an interest in the land that confers a right to occupy the land; in the case of Métis land, a person having a right or interest in land recorded on the Métis title register pursuant to the *Métis Settlements Land Registry Regulation*; the holder of a permit for a coal mine.
oil/mineral/bitumen battery	A system or arrangement of tanks or other surface equipment or devices receiving the effluent of one or more wells for the purpose of separation and measurement before the delivery to market or other disposition.
oil effluent	Oil, gas, and water in any combination produced from one or more oil wells or recombined oil well fluids that may have been separated in passing through surface facilities.
oil well	A well that produces primarily liquid hydrocarbons from a pool or a portion of a pool wherein the hydrocarbon system is liquid or exhibits a bubble point on reduction of pressure, or any well so designated by the AER.
oil loading/unloading facility (truck terminal)	A system or arrangement of tanks and other surface equipment receiving crude oil by truck for the purpose of delivering crude oil into a pipeline.
oil sands scheme approval number	The number assigned an approval of a scheme or operation for the recovery of oil sands or crude bitumen under the *Oil Sands Conservation Act*.
oil satellite	An arrangement of surface equipment (not including oil storage tanks) located some distance between a number of wells and the main battery that will receive the effluent and separate and measure the production from each well, after which the fluids are recombined and piped to the main battery for further treatment; water handling equipment may be included.
oilfield waste	An unwanted substance or mixture of substances generated from the construction, operation, or reclamation of wells, facilities, and pipelines.

oilfield waste management facility	A facility whose operation is approved by the AER. Includes a waste processing facility, a waste storage facility, a waste transfer station, a surface facility associated with a disposal well, a biodegradation facility, an oilfield landfill, a thermal treatment facility, and any other facility for the processing, treatment, storage, disposal, or recycling of oilfield waste.
operator	A person or company that has control of or undertakes the day-to-day operations and activities of a facility, pipeline, or well, whether or not that person is also the licensee for the facility, pipeline, or well.
partial pressure	The pressure exerted by one component of a natural gas mixture when isolated in a container.
participant	An organization, community, group, or individual with a stake in the discovery, development, and delivery of Alberta's resources.
participant involvement	Participant involvement encompasses all aspects of public, industry, and regulator interactions and communications. It means that each organization, community, group, and individual with a stake in the discovery, development, and delivery of Alberta's resources may be a participant.
perforation	The holes placed through the casing and cement into the formation using a perforation gun or by cutting the casing and cement using sand-laden fluids to expose a formation.
personal consultation	Consultation through face-to-face visits or telephone conversations with identified parties and providing the required information packages.
pipeline abandonment	The permanent deactivation of a pipeline or part of a pipeline.
pipeline discontinuance	The temporary deactivation of a pipeline or part of a pipeline.
pipeline installation	Any equipment, apparatus, mechanism, machinery, or instrument incidental to the operation of the pipeline. This includes compressor stations, pump stations, line heaters (categories C and D), oil loading/unloading facilities, and tank farms associated with pipelines carrying process sales product.
pipeline liner	A tubular product that is inserted into buried pipelines to form a corrosion-resistant barrier or separate freestanding pressure-containing pipe.
pipeline right-of-way plan	A scaled sketch plan of the pipeline right-of-way that includes Alberta township survey detail and identifies land ownership, water body crossing, and other directly adjacent or affected rights-of-way.
pipeline removal	The removal of a pipeline or part of a pipeline.

pipeline resumption	The resumption of operations of a pipeline or part of a pipeline to its original licensed parameters.
pipeline line split	Division of a line segment into multiple segments, each assigned a line number.
primary containment device	A device used to physically contain materials produced, generated, and used by the upstream energy industry, including single-walled tanks and containers.
processing equipment	Equipment used for the extraction of components such as water, H_2S, and liquids from gas or oil.
process vessel	A heater, dehydrator, separator, treater, and any vessel used in the processing or treatment of produced gas or oil.
project	A network of facilities, pipelines, and wells that connects to a common facility.
public facility	A public building, such as a hospital, rural school, or major recreational facility, situated outside of an urban centre that can accommodate more than 50 individuals or that requires additional transportation to be provided during an evacuation.
public notice	In accordance with the *Alberta Energy Regulator Rules of Practice*, the delivery, circulation, or advertising by the AER of a notice stating that the AER might take action in a proceeding specified in the notice. The cost of advertising public notices is borne by the applicant.
publicly used development	Places where the presence of 50 individuals or fewer can be anticipated (e.g., places of business, campgrounds, cottages, churches, and other locations created for use by the nonresident public).
pump station	A system of equipment located at intervals along a main pipeline to maintain flow to the receipt point.
re-entry	The re-entry of an abandoned wellbore by a company other than the original licence holder.
refer status	A corporate status indicator noting the licensee's inability or unwillingness to comply with requirements. This status will be considered by the AER when deciding to approve or deny any pending or future applications to the AER involving the licensee.
release	Any unintended discharge of product to the environment from a well, facility, or pipeline.
requirement	A rule that industry has an obligation to meet.
residence	A dwelling that is occupied full time or part time.

resident	A person occupying a residence on a temporary or permanent basis.
resumption of drilling operations	Re-entry of an existing wellbore by the licensee, whether abandoned or not, for the purpose of deepening, whipstocking, recompleting (abandoned well only), or horizontal recompletion.
right-of-way	The land upon which a legal right-of-way is granted over another person's property. This right can be acquired by means of an easement or by a right-of-entry order.
routine application	One where the applicant met all requirements (including participant involvement), there are no outstanding public or industry concerns, and regulatory variances have been obtained.
setback distance	The minimum required distance between a well, pipeline, or other facility and land use development such as a surface improvement, permanent dwelling, unrestricted country development, urban centre, or public facility.
solution gas	Gas that is dissolved in solution with produced oil or bitumen.
stress level	Stress in the pipe wall produced by fluid pressure in the pipe.
stock tank vapours	The small volume of dissolved gas present in storage tanks.
straddle plant	Surface equipment intended to reprocess marketable gas for the purpose of ethane extraction.
sulphur emissions	The release of sulphur-containing compounds, including SO_2, H_2S, and total reduced sulphur compounds.
surface development	Dwellings that are occupied full time or part time, publicly used development, public facilities such as campgrounds and places of business, and any other surface development where the public may gather on a regular basis. Includes residences immediately adjacent to the EPZ and those from which dwellers are required to egress through the EPZ.
surface improvement	A railway, pipeline, canal, or other right-of-way, road allowance, surveyed roadway, dwelling, industrial plant, aircraft runway or taxiway, buildings used for military purposes, permanent farm buildings, school, or church.
suspension	The temporary cessation of operations at a well, pipeline, or facility in the manner prescribed by the regulations or directed by the AER—includes any measures required to ensure that the well, pipeline, or facility is left in a safe and secure condition.
tank	A device designed to contain materials produced, generated, and used by the energy industry that is constructed of impervious materials.

tank farm	A system or arrangement of tanks or other surface equipment associated with the operation of a pipeline and that may include measurement equipment and line heaters but does not include separation equipment or storage vessels at a battery approved under the *Oil and Gas Conservation Act*.
temporary facility or pipeline	A facility or pipeline that will be in use for a period of 12 months or less.
terminating formation	For the purpose of well licensing, the deepest formation in which the well will terminate and which the applicant has the right to produce for all intended purposes of the well.
thin-film internal coatings applied in situ	A thin polymer film applied to the internal surface of an existing pipeline (i.e., in situ).
unrestricted country development	Any collection of permanent dwellings situated outside of an urban centre and having more than eight permanent dwellings per quarter section.
unsatisfactory event	A contravention of a regulation or requirement.
urban authority	The administrator of a city, town, new town, village, summer village, or hamlet with not fewer than 50 separate buildings, each of which must be an occupied dwelling or other incorporated centre.
urban centre	A city, town, village, summer village, or hamlet with no fewer than 50 separate buildings, each of which must be an occupied dwelling, or any similar development the AER may designate as an urban centre.
variance	Permission to alter a requirement.
water body	Natural or man made; contains or conveys water continuously, intermittently, or seasonally. A natural water body is any location where water flows or is present, whether the flow or the presence of water is continuous, seasonal, intermittent, or occurs only during a flood. This includes the bed and shore of a river, stream, lake, creek, lagoon, swamp, marsh, slough, muskeg, or other natural drainage, such as ephemeral draws, wetlands, riparian areas, floodplains, fens, bogs, coulees, and rills. Examples of a man-made water body include a canal, drainage ditch, reservoir, dugout, or other man-made surface feature.
well spacing	The normal DSU for a gas well is one section (1 well per 256 hectares); for an oil well, it is one quarter section (4 wells per 256 hectares).
working interest participant	A person who owns a beneficial or legal undivided interest in a well or facility under agreements that pertain to the ownership of that well or facility.