Directive 065: Resources Applications for Oil and Gas Reservoirs

November 12, 2024

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 is requiring any applicant seeking approval for an activity that would be located within the boundary of an approved regional plan to meet the requirements below. These requirements will be formally incorporated into the directive at a later date.

A) For an activity to be located within the boundary of an approved regional plan, the applicant must assess

   I) 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;

   II) 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

   III) 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.

B) The applicant must retain the information for requirement A at all times and provide it on request unless otherwise indicated below. The information must be sufficient to allow the AER to assess an application under the applicable regional plan.

C) The applicant must submit the information from requirement A if the proposed activity to be located within the boundary of an approved regional plan

   I) 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;

   II) is inconsistent with the land uses established in the applicable regional plan or any of the outcomes, objectives, and strategies in that same plan; or

   III) 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.

D) The applicant must submit the information from requirement A if it 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 also 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. For more information, contact Alberta's Land Use Secretariat by phone at 780-644-7972 or by email to LUF@gov.ab.ca.

For more information on the requirements above, refer to *Bulletin 2014-28: Application Requirements for Activities within the Boundary of a Regional Plan* or email regional.plans@aer.ca. This bulletin rescinds and replaces *Bulletin 2012-22: Application Procedures for Approval of Activities Located In or Near the Boundaries of the Lower Athabasca Regional Plan*, which is an earlier bulletin that was issued regarding the AER's compliance with approved regional plans under the *Alberta Land Stewardship Act*.

Directive 065

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Resources Applications for Oil and Gas Reservoirs

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How to Use This Directive

Directive 065 details the process to apply to the Alberta Energy Regulator (AER) for all necessary approvals to implement the strategy and plan to deplete a pool or portion of a pool using one resource application. Previously, the requirements were mainly found in part 15 of the *Oil and Gas Conservation Rules* (*OGCR)*.

This directive also enables you to review in a single document the application requirements and the explanations for those requirements for most conventional oil and gas reservoir topics considered in an application for AER approval. "Must" indicates a requirement for which compliance is required and is subject to AER enforcement, while "recommends" indicates a best practice that can be used but is not an AER requirement and does not carry an enforcement consequence. The AER will conduct periodic reviews of this directive's continued usefulness for applicants and conduct updates based on feedback received.

Questions about application types discussed in *Directive 065* may be directed to the Resources Applications help line at 403-476-4967 or Resources.Applications@aer.ca.

Introduction

Specific resource applications are required to allow the AER and potentially affected parties, often with competing interests, to understand and test the appropriateness or impact of depletion plans at critical milestones. Other resource applications may address revisions to the baseline set of depletion or equity rules and reservoir descriptions. Some resource applications address known equity disputes arising from different ownership, limited opportunity to produce, or access constraints to established facilities. If such issues are not resolved, these applications go directly to a hearing.

The AER reviews all resource applications to ensure that the appropriate level of reservoir engineering and geological science is applied in managing poolwide depletion and that potential impacts on other stakeholders are identified and dealt with fairly. Because individual reservoirs are unique, detailed assessments may be necessary to ensure that the depletion plan is appropriate and recovery is in the public interest. You must provide sufficient up-front information and analysis to support the reasonableness of your applications.

The AER has compiled this comprehensive directive to support a level playing field for all applicants. Applicants are expected to know and understand requirements and file accurate and complete applications. AER staff will not complete missing application requirements, such as raw data collection and supporting analytical discussion. Instead, AER staff will test assumptions, check completeness and accuracy of data and assessments, and test alternatives.

What This Directive Contains

This directive includes the Resources Applications – Schedule 1 registration form, which must be completed for all resources applications for oil and gas reservoirs made under this directive; guidelines on notification requirements; and seven units that address detailed information requirements for specific regulatory topics, as well as appendices giving reference sources and other support information.

Applicants must prepare the following resources applications using the on-line Schedule 1 form. This will provide the AER with key information about the applicant, the type of application, the area of application, and details of notice to potentially affected parties undertaken by the applicant.

The resources applications for which this directive applies are divided into units as follows:

1) **Equity**: rateable take, common purchaser, common carrier, common processor, and compulsory pooling
2) **Conservation**: enhanced recovery scheme (gas cycling, waterflood, immiscible gas flood, miscible flood, CO_2 EOR storage), concurrent production, and pool delineation and ultimate reserves
3) **Production Control**: commingled production, good production practice (primary depletion pools), gas-oil ratio penalty relief, special maximum rate limitation, and gas allowable
4) **Disposal/Storage**: disposal (water and waste), acid gas disposal, CO_2 sequestration, and underground gas storage
5) **Approval Transfers**: change in name of the holder of an AER approval and change in holder of an AER approval
6) **Gas and Ethane Removal**: short and long-term natural gas removal, short-term ethane removal.
7) **Special Well Spacing**: holdings or units, special drilling spacing units, rescind a special drilling spacing unit, rescind a holding or unit, and modify spacing.

The appendices include

- list of references
- notification templates
- application for gas-oil ratio penalty relief (form O-33)
- transfer of approval form
- enhanced recovery scheme application form
- gas and ethane removal application forms

- gas reserves data sheet
- EAS well spacing application forms and explanatory notes
- special well spacing notification templates
- special well spacing attachment examples
- standard target areas and buffer zones
- target area descriptions for special well spacing before October 6, 2011

You are strongly encouraged to become familiar with the references listed in appendix A before completing your application.

What's New in This Edition

Requirements around induced seismicity have been added as section 4.1.8. Some changes to acid gas disposal and carbon capture, utilization, and storage requirements have also been made:

- Notification requirements in tables 1 and 3 have been expanded to require disposal applicants to notify Crown agreement holders.
- The two-step application process now applies to all enhanced recovery, disposal, and sequestration schemes.
- Requirements around equity for acid gas disposal have been added to section 4.1.3.
- Requirements around containment assurance have been added to section 4.1.5.
- Although all CO_2 sequestration schemes are regulated under this directive, changes have been made to section 4.1.6, section 4.1.7, and appendix P related to small-scale and remote CO_2 sequestration schemes.

Procedure for Reviewing Application

Figure 1 shows the overall oil and gas resources applications process, figure 2 shows the oil and gas resources applications evaluation process, and figure 3 shows the well spacing applications evaluation process.

Step 1: Application Registration

All resources applications contained in this directive must be submitted electronically through DDS on the AER website at www.aer.ca. Copies of the forms can be found on the directive's landing page and on the "AER Forms" page of our website at www.aer.ca > Regulating Development > Rules and Directives > AER Forms. The AER assigns each application package a unique application number. This information is communicated to the applicant within minutes of the application registration. Applicants can also confirm the registration and contact information of their application by checking the Integrated Application Registry (IAR) Query, accessible from the Systems and Tools portal on the AER's website.

Note that all data must be submitted using metric units (SI).

Step 2: Corporate Record Check

All applications are subject to a corporate check to verify acceptable performance records and other information in AER files.

Applicants seeking formal approval must hold a valid company code issued by the AER's Liability Management Group. If you are a first-time applicant, you must obtain a company code by filing a corporate profile with the AER's Liability Management Group. Information packages are available from the Liability Management Group at LiabilityManagement@aer.ca. You must update your corporate profile when asked to do so by the AER.

AER approvals identify the applicant as the holder of the approval, and this party is responsible and accountable for compliance with all regulations and the approval conditions. Applicants requesting changes to a general order of the AER, reservoir description, and operational practices not requiring a change to an approval do not need to have a company code but must have a valid interest in the pool.

If you are on "refer" status due to an unresolved serious noncompliance problem, the AER may ask additional questions, including questions related to corporate accountability, technical competency, and corporate commitment to compliance with provincial standards. In the case of a "refer" status, the AER Executive Committee may be directly involved in the consideration of any application, which may include a decision to go to a hearing. Otherwise, the application is normally reviewed and, if appropriate, approved by the delegated work groups within the AER.

Step 3: Application Returned or Delayed if Incomplete

Effective October 1, 2000, the AER will no longer process an application identified in this directive if it is substantially incomplete (i.e., has a major deficiency). It will be returned to you with an explanation. An example of such a major deficiency is the complete omission of an entire key information segment of any unit requirements, such as the geological description. If the application has minor deficiencies, such as lacking specific information needed to make a decision, you will be provided with a clear explanation and given five working days to respond. Failure to respond in this timeframe will result in the AER closing and returning your application with written notification of the reason. The AER is prepared to correct small errors in the submitted information, as long as applicants show improvement in submitting better-quality applications.

Note that if the AER returns a severely deficient and incomplete application that you filed in response to an AER request, such as for improvement in recovery or operational performance, you will be subject to any consequences or penalties previously identified at the time of the request.

Step 4: Application Evaluation

This directive identifies some circumstances that may reduce application requirements and, in turn, result in a faster decision on the application. You may want to consider the long-term benefits of creating some of these circumstances, such as equity agreements and poolwide plans, before you file a competitive, partial pool application.

The evaluation of your application may also be expedited if your definition of the pool extent is consistent with the AER's pool designation or you provide a discussion on any variances. The failure to resolve significant differences, such as pool delineation, before the application is filed could add considerable time to the application process and raise issues that are better dealt with beforehand.

When evaluating an application, the AER reviews a pool's unique features, if any, to assess whether additional information, analysis, or consultation beyond what is identified in the directive is required. As explained in the Resources Applications Notification Guidelines and individual units of this guide, in those cases where the applicant has chosen to conduct notification the AER will require submission of documentation describing your notification program.

Concerns/Dispute Resolution

The AER expects applicants to conscientiously address all relevant concerns raised by potentially adversely affected parties. Should disputes arise, the AER expects the parties to discuss the issues and options for resolution, including the use of third-party mediators. AER staff, if requested, can assist in explaining AER rules and in facilitation.

If you conclude that further discussion is unlikely to resolve issues, you should inform the AER, outlining concerns, steps you have taken to resolve problems, and your recommended course of action. Note that outstanding statements of concerns can result in an AER hearing. Should a hearing be called, both you and the intervener may be asked to file additional substantiating evidence. Matters of confidentiality and disclosure should be addressed and determined by the parties prior to submission of this evidence.

Documented Decisions/Compliance

AER decisions on the resource applications listed in this directive are issued in written format and generally include a letter and either a formal site-specific approval or a regional or provincial order.

AER requirements for resource activities covered by *Directive 065* are set out in the *Oil and Gas Conservation Act*, *OGCR*, this directive, and conditions of approval. These are the requirements that you have a legal obligation to meet.

You must not assume that an approval has or will be granted just because an application has been submitted.

If an unauthorized activity occurs or if conditions of approval are not met, immediate corrective action, such as the shut-in of well operations, is required. See specific sections of *Directive 065* for details of compliance requirements.

Voluntary Self-Disclosure

Licensees are encouraged to actively monitor compliance using tools such as surveillance and audits. Send self-disclosure information to

Email: ResourceCompliance@aer.ca
Fax: 403-297-8122
Mail: Alberta Energy Regulator
Resources Applications, Enforcement and Surveillance Section
Suite 1000, 250 – 5 Street SW
Calgary, Alberta T2P 0R4

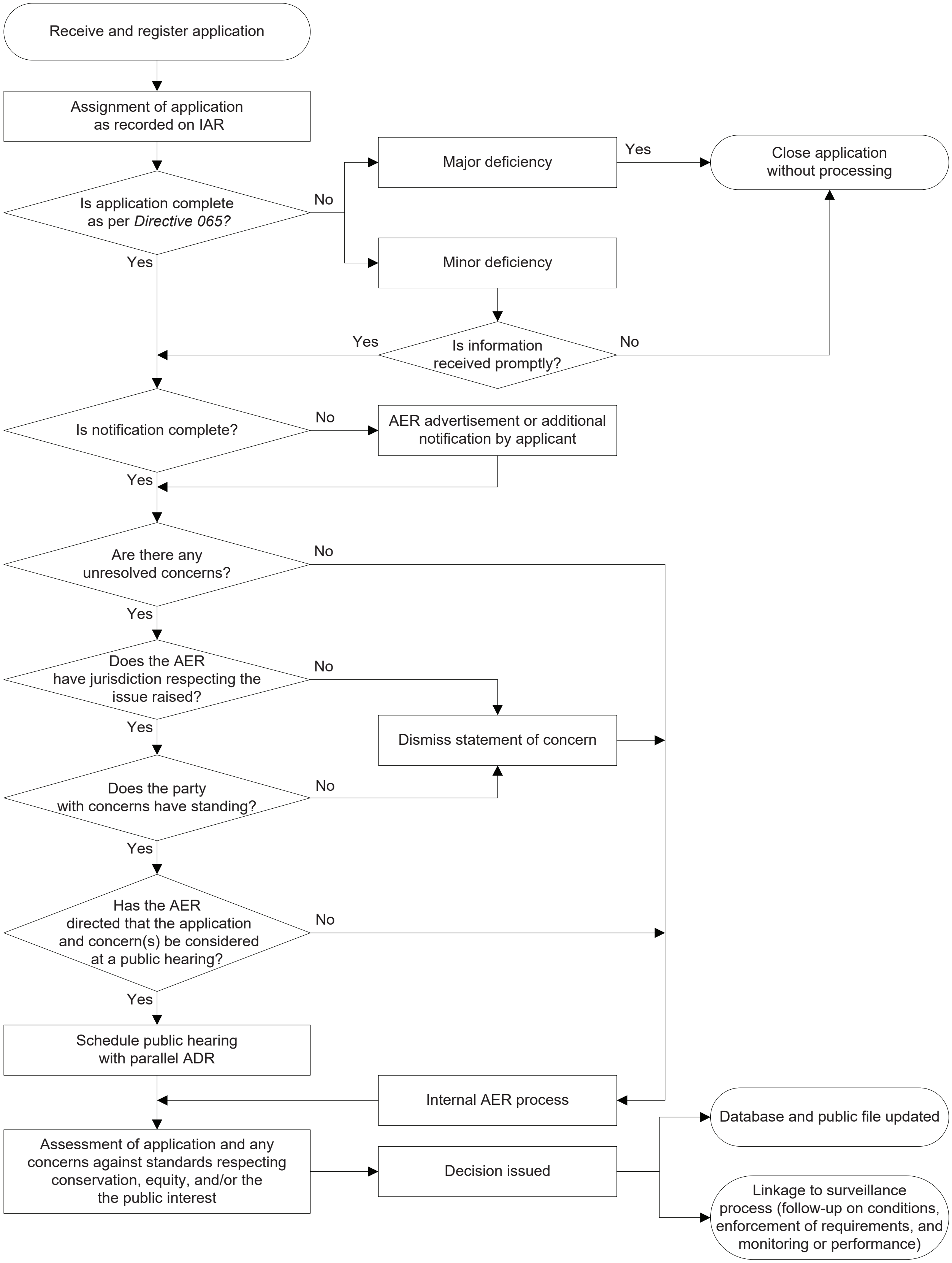

Figure 1 Resources applications process

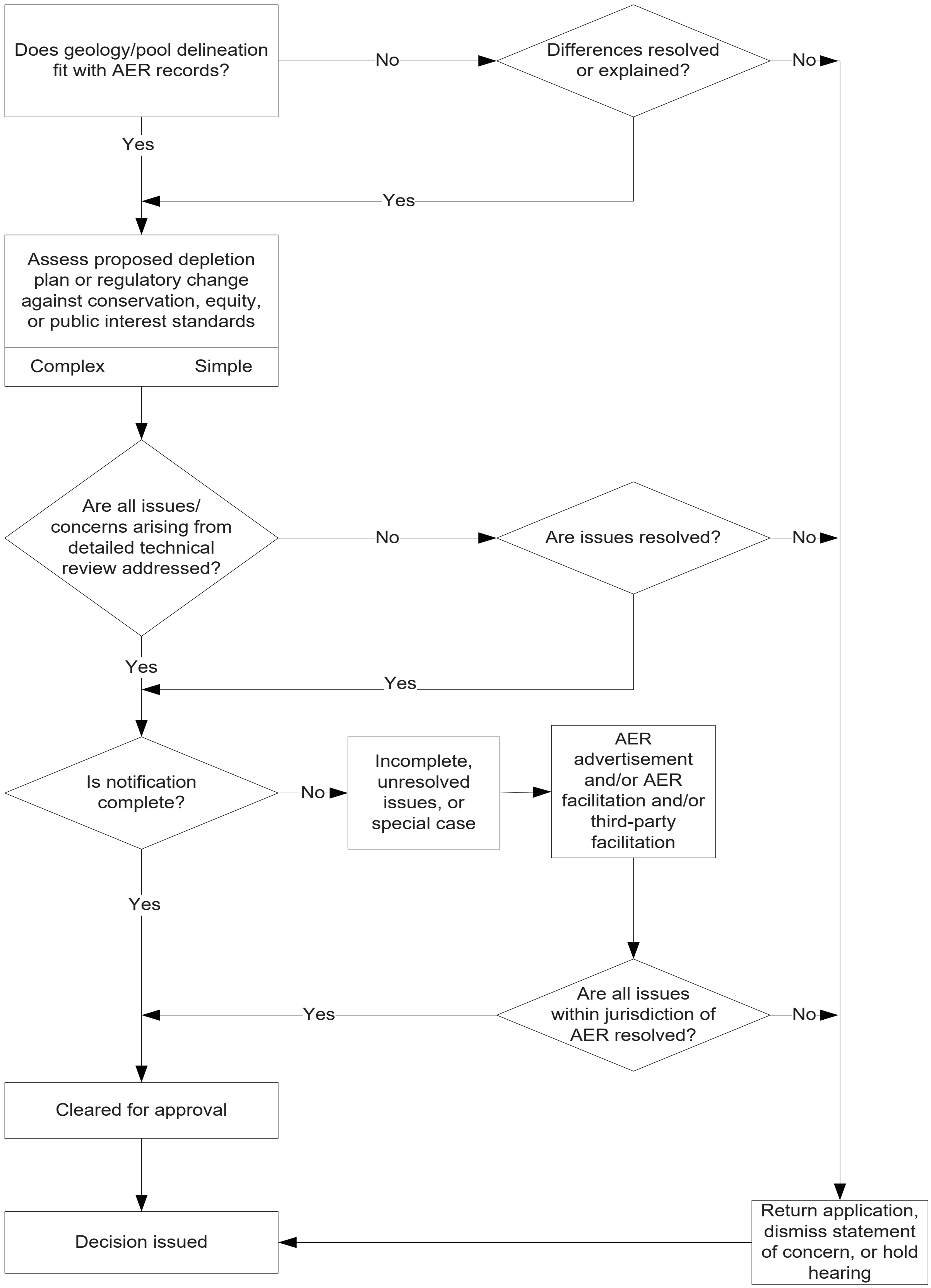

Figure 2 Resources applications evaluation

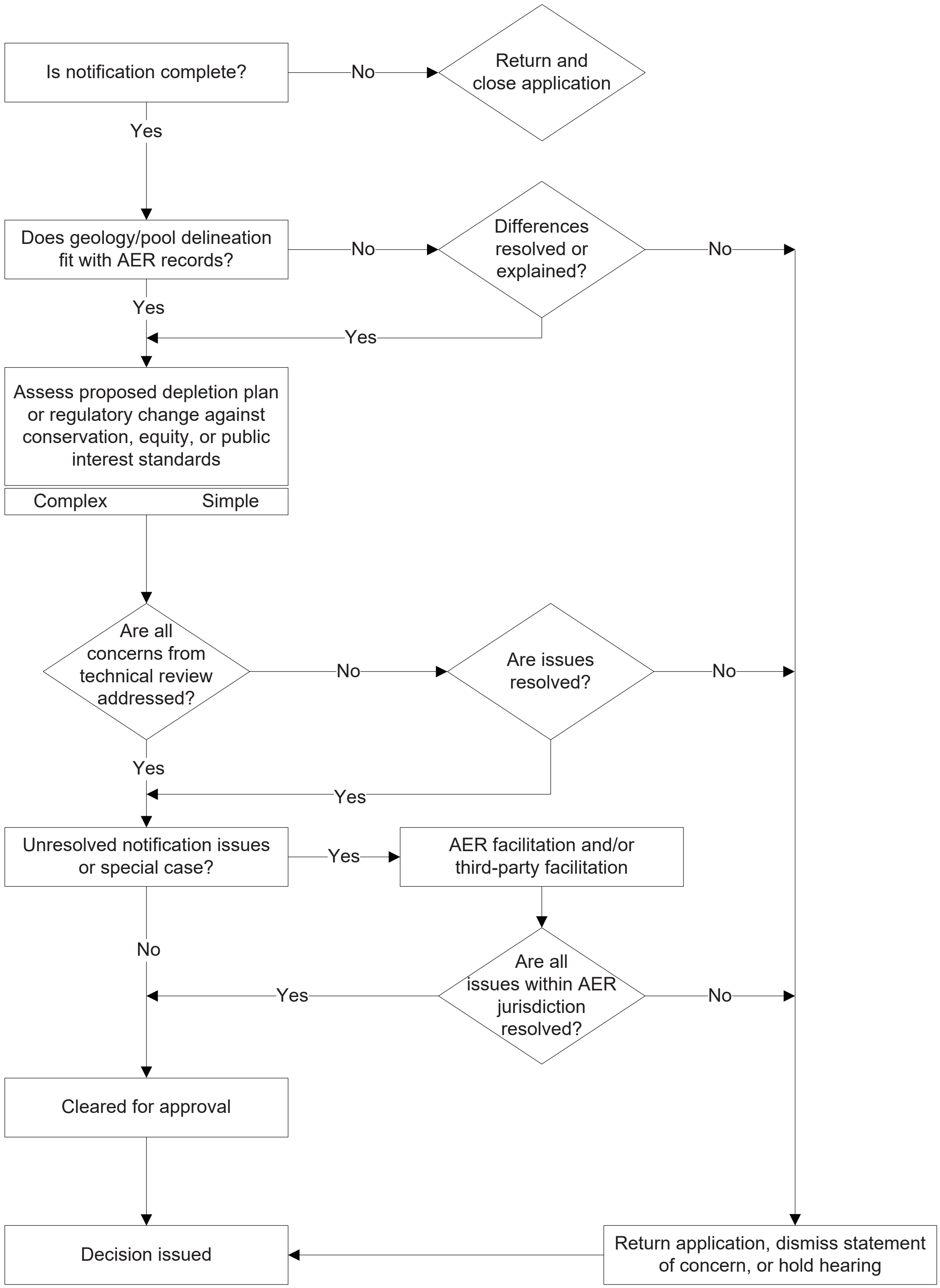

Figure 3 Well spacing applications evaluation

Resources Applications Notification Guidelines

When to Notify

Effective notification and consultation programs are critical not only to ensure an efficient regulatory process but to promote long-term relationships. The AER prefers, and requires for some resource application types, that both industry and public (where required) notification be completed prior to the filing of the applications.

Whom to Notify

Minimum notification requirements for specific types of resources applications are included in tables 1, 2, and 3 in this section and table 3.1 in Unit 3. In addition to meeting the minimum notification requirements, the AER expects you to review your situation and consider whether there are potentially directly and adversely affected parties outside the minimum notification areas and, if so, also provide notification to these parties.

In some cases, the AER requires notification for informational purposes only. This type of notification provides information regarding a potential development to support, promote, and encourage early and ongoing discussions between parties.

How to Conduct Notification

Notification is the first step in providing information and is usually conducted through written correspondence, while consultation must occur face to face or by telephone. Early, proactive notification programs are more likely to result in positive relationships. To this end, the AER believes that newspaper advertisement may not meet these objectives and should only be used to supplement direct notification in extenuating circumstances. If you know there will be contentious or complex issues respecting a resources application, personal consultation may be preferable as a first step rather than notification. Notification programs that do not provide for direct notice to a person should be discussed with the AER prior to conducting the program.

You should provide notification of a proposed application by means of a letter that includes adequate information to allow persons to understand the proposed development and the impact that it may have on them. Examples of notification letters are included in appendix B and appendix J. Notification should take into consideration whether the person being notified is an oil and gas company, a Freehold mineral owner, or a landowner or occupant. You must include applicant contact information in the notification letter, as well as directions about what action a person should take if there is a concern. Stakeholders should be directed to submit any concerns directly to the applicant, but with the option to submit them directly to the AER.

In providing notification, you must take into consideration possible delays in delivery of the notification package. Each person notified must be given a minimum of 15 business days from the date the letter was received to respond. A signed letter of consent or nonobjection to the proposal is not required. However, it should be clear in the letter that if the person notified does not respond to the notification package, filing (if not filed) and processing of the application with the AER will proceed without further contact.

Consequences of Incomplete Notification

For some application types, the AER requires that you provide a description of your notification program and documented evidence of the results in your application, including a list of the persons notified and a copy of the notification letter.

The AER will review your notification information to ensure that you have met the requirements in this directive. Should it be determined that the notification provided was inadequate, the application, in most cases, will be **closed**.

If an application has been approved without a hearing, a directly and adversely affected party may file an application with the AER for a regulatory appeal and an appeal hearing may be held. The approval may be suspended pending the outcome of the regulatory appeal.

Responding to Concerns Raised During the Notification Process

The AER expects applicants to engage in meaningful discussions with any person who has raised concerns or has questions respecting a proposed application. It is expected that applicants will make substantial efforts to resolve the matter prior to filing and during the review of a resources application, including use of third-party mediators, as discussed in the AER's Alternative Dispute Resolution (ADR) program described in AER *Manual 004: Alternative Dispute Resolution Program and Guidelines for Energy Industry Disputes*.

If an applicant has made no attempt to respond to a person who has expressed concerns or is seeking understanding or answers to questions, the application, in most cases, will be **closed**.

The AER recognizes that discussions may come to an impasse or that a person who has expressed concerns may decline to participate in the ADR process. Additionally, in some cases, a company may consider the statement of concern to be not relevant to the issues of the application and that beyond initial efforts it should not be required to attempt to resolve the issue. In these cases, the company may proceed to file its application (if not filed) and to include any statements of concern about the application, its response to the statements of concern, and a discussion of its view of how the AER should proceed with the application.

Table 1 Minimum notification requirements required prior to filing application

Application type (section in *Directive 065*)	**Parties to notify**	**Area of notification**
Special well spacing (Unit 7)	• All mineral rights owners (excluding the Crown and owners that have leased their rights) • All mineral rights lessees	*Regardless of provincial boundaries*, the applied-for area and the area within • one quarter section of the application area for oil applications and • within one section of the application area for gas applications
Rescind Special DSU	• All mineral rights owners (excluding the Crown and owners that have leased their rights) • All mineral rights lessees	The applied-for area only
EOR scheme (amendment) (2.1)	• All licensees of abandoned wells that penetrated the pool and licensees of wells completed in the pool	The applied-for approval area and the area within 800 m of any proposed enhanced oil recovery injector
EOR scheme (new) (2.1)	• All licensees of abandoned wells that penetrated the pool and licensees of wells completed in the pool	The applied-for approval area and the area within a quarter section of the applied-for approval area
CO_2 EOR storage scheme (amendment) (2.1)	• All licensees of abandoned wells that penetrated the pool and licensees of wells completed in the pool	The applied-for approval area and the area within 1.6 km of any proposed enhanced oil recovery injector
CO_2 EOR storage scheme (new) (2.1)	• All licensees of abandoned wells that penetrated the pool and licensees of wells completed in the pool	AER-designated pool
Gas cycling scheme (amendment)	• All licensees of abandoned wells that penetrated the pool and licensees of wells completed in the pool	The applied-for approval area
Gas cycling scheme (new)	• All licensees of abandoned wells that penetrated the pool and licensees of wells completed in the pool	The applied-for approval area and the area within one section of the applied-for approval area
Concurrent production (2.4)	• Unit operator (if applicable) • Approval holder of scheme (if applicable) • All well licensees	AER-designated pool
CO_2 Sequestration (4.1.6)	• Unit operator (if applicable) • Approval holders of schemes • All well licensees, including those of abandoned wells • All mineral lessees • All mineral lessors • Geothermal lease holders • Holders of Crown agreements or authorizations to sequester CO_2	Notifications should cover all zones that overlie and underlie the storage zone's maximum calculated injection fluid area plus 1.6 km. Notifications should also be provided to adjacent sequestration agreement or authorization holders within the approved zone within the sequestration boundary, covering all zones that overlie and underlie within the sequestration agreement boundary.

Application type (section in *Directive 065*)	Parties to notify	Area of notification
Waste disposal (Class I)[1] (4.1)	Industry • Unit operator (if applicable) • Approval holder of scheme • All well licensees, including those of abandoned wells • All mineral lessees • All mineral lessors • Holders of Crown agreements or authorizations to sequester CO_2 • Geothermal lease holders	A radius of 1.6 km from the proposed disposal well where the disposal zone is known to be present
	Public • Landowners/occupants	A radius of 0.5 km from the proposed disposal well
Acid gas disposal[2] (4.1)	• Unit operator (if applicable) • Approval holder of scheme (if applicable) • All well licensees, including those of abandoned wells • All mineral lessees • All mineral lessors • Holders of Crown agreements or authorizations to sequester CO_2 • Geothermal lease holders	If into a depleted hydrocarbon pool, the AER-designated pool; if into an aquifer, a radius of 1.6 km from the section containing the disposal well in the target zone

[1] Notification and consent may be required as part of any request for a surface facility approval associated with waste disposal as per *Directive 058: Oilfield Waste Management Requirements for the Upstream Petroleum Industry*. A surface facility approval must be obtained from the AER's Facilities Applications Group and/or Alberta Environment and Protected Areas before an approval for a waste disposal well can be issued.

[2] All production, injection, or disposal operations that contain fluids with any H_2S must meet the requirements of *Directive 071: Emergency Preparedness and Response*.

Table 2 Minimum consultation requirements prior to filing applications

Application type (section in *Directive 065)*	Consultation and documentation of negotiations with	Area of contact
Rateable take (1.1)	• All well licensees	AER-designated pool if present; otherwise applicant's pool interpretation
Common carrier/processor/ purchaser (1.2, 1.3, 1.4)	• Carrier, processors, or purchasers involved • All well licensees	Not applicable In pool
Compulsory pooling (1.5)	• All mineral lessees • All mineral lessors of unleased tracts	AER-designated drilling spacing unit

Table 3 Minimum notification requirements prior to filing applications[1]

Application type (section in *Directive 065*)	Parties to notify	Area of contact
Commingled production (3.1)	• Refer to section 3.1 for notification requirements	
Good production practice/ special maximum limitation/gas-oil ratio penalty relief (3.2.2, 3.2.3, 3.2.4)	• Unit operator (if applicable) • Approval holder of scheme (if applicable) • All well licensees	AER-designated pool
Gas allowable (3.3)	• Unit operator (if applicable) • Approval holder of scheme (if applicable) • All well licensees	AER-designated pool plus 1600 m surrounding the pool
Disposal except waste disposal (Class I) and acid gas disposal (4.1)	• Unit operator (if applicable) • Approval holder of scheme (if applicable) • All well licensees, including those of abandoned wells • Holders of Crown agreements or authorizations to sequester CO_2 • Geothermal lease holders	A radius of 1.6 km from the proposed disposal well where the proposed disposal zone is known to be present
Underground gas storage (4.2)	• Unit operator (if applicable) • Approval holder of scheme (if applicable) • All well licensees, including those of abandoned wells • All mineral lessees • All mineral lessors	The AER-designated pool boundary of the proposed storage pool and a 1.6 km radius from that pool boundary; notification should cover all zones, including those that overlie and underlie the storage pool

[1] These are minimum requirements. The consequences of incomplete notification are discussed in the preceding text.

Unit 1 Equity

1.1 Application for a Rateable Take Order

1.1.1 Background

The purposes of the *Oil and Gas Conservation Act* (*OGCA*) are, among other things, to effect the conservation of oil and gas resources, to afford each owner the opportunity of obtaining its share of the production of oil or gas from any pool, and to provide for economic, orderly, and efficient development in the public interest. Section 36 of the *OGCA* mandates the AER to address all three of these purposes. Historically this legislation has been used only in the equity context and to allow for economic, orderly, and efficient development; other sections of the *OGCA* have been used to ensure conservation of resources.

Under section 36, the AER may limit the amount of gas that may be produced and/or distribute the amount of gas that may be produced from a pool or part of a pool. Historically, this legislation has been used to authorize the distribution of gas production among wells in a nonassociated gas pool.

1.1.2 When to Make This Application

A situation that could warrant an application under section 36 of the *OGCA* would typically involve a number of gas wells of different ownership in a pool being on production. One owner believes its reserves are being inequitably drained because its well has been placed on production at rates that do not allow the well to capture the owner's share of the pool reserves. The well's rate may be restricted by pipeline or processing capacity or by a gas sales contract.

In the case where the rate limitation is due to pipeline or processing capacity, the owner has capacity or its own facilities and believes that it would not represent economic, orderly, and efficient development to build or obtain additional capacity. Where the limitation is due to a gas sales contract, the owner has been unable to adjust the contract or produce gas in excess of the contract to allow for an equitable rate of production.

1.1.3 How the AER Processes the Application

The AER considers the issuance of a rateable take order to be a very significant action because it has the potential to override contractual arrangements put in place through normal business practices. Consequently, before approving an application, the AER requires an applicant to demonstrate that it is being deprived of the opportunity to obtain its share of production from the pool. The applicant must show that drainage has occurred and continues to occur or that it can be expected to occur with a very high degree of certainty. Additionally, the drainage must be a result of the applicant not having an opportunity to produce its share of production. The restriction in rate must not be due to limitation in well capability. The AER has previously ruled that where the only limitation on production is well capability, a producer is not being deprived of an opportunity to obtain an equitable share of production (*Decision 85-5*).

Each application for a rateable take order will likely proceed to a public hearing.

1.1.4 Requirements for an Application for a Rateable Take Order (file 12 copies)

Requirements	Comments
1) A statement of what is being requested, including a) a reference that the application is being made under section 36 of the *OGCA*, and b) the pool and wells to which the order would apply.	For example, HP Gas Company applies for an order under section 36 of the *OGCA* distributing gas production among wells in the Woodword Viking A Pool, which includes the wells with the unique identifiers of …
2) A discussion giving the reasons why you are requesting the order, including a description of the circumstances that in your opinion have led or will lead to an inequitable situation.	
3) Documentation showing your attempts to negotiate a solution to the problem, including a) identification of all parties involved and the nature of their issues and concerns, and b) an outline of the attempts to resolve the issues, including type of discussions held, timing, and frequency.	You must have made substantial efforts to resolve the situation; the application should be a final resort. You should also continue your efforts to resolve the matter on a voluntary basis (including consideration of a third-party mediator) after the application has been filed with the AER. Your discussion must include why the negotiations did not lead to a settlement and what dispute resolution efforts were conducted. Matters of confidentiality and disclosure should be addressed and determined by the parties prior to submission of the application.

4) Your geological interpretation of the pool involved, including

   a) a net pay isopach map of the pool, including both oil and gas if there is an associated pool;

   b) an interpreted and annotated log cross-section or representative well logs showing

      i) stratigraphic interpretation of the zones of interest,

      ii) interpretation of fluid interfaces present,

      iii) completions and treatments to the wellbores, with dates,

      iv) cumulative production,

      v) finished drilling date and kelly bushing (KB) elevation, and

      vi) the scale of the log readings; and

This information should show that your well is part of the subject pool. The net pay map should show the entire pool and illustrate wells outside the pool that control the edges of the pool.

If there is a dispute among the parties involved regarding the delineation of the pools in question, an annotated cross-section should be included in the application; if there is no dispute respecting this issue, an annotated representative well log is sufficient for the purposes of the application.

   c) a tabulation of the interpreted net pay, porosity, and water saturation for each well in the pool, along with the cutoffs, methodology, formulas, and constants used.

This allows the AER to assess your mapping and reserves calculation requested in the following item. In addition, these data may be used to allocate production (see item 8 below).

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5) An evaluation of the oil and gas reserves for the pool and for your lands, including

   a) an estimate of the initial oil volume and gas volume in place,

   b) an estimate of the oil and gas recovery factors,

The reserves estimates confirm that there are reserves available for production.

c) a description of the methods used in determining (a) and (b) above (e.g., material balance, volumetric analysis, model study, a comparison of analog pools), and	
d) the supporting data used in determining (a) and (b) above and the sources of the data (i.e., pressure/volume/temperature [PVT] properties and source, pressure data and source).	All data used in obtaining the reserves estimates should be provided so that your analysis can be duplicated using information supplied in this application.
6) Deliverability test data showing that your well is capable of producing at an economic rate from the pool to which the proposed order would apply.	A summary of the deliverability test data may be used provided the detailed test data have been filed in accordance with *Directive 040: Pressure and Deliverability Testing Oil and Gas Wells*.
7) Where drainage is alleged, a discussion including	
a) evidence showing that the reserves underlying your lands have been drained subsequent to the completion of your well in the pool, and b) an estimate of the total amount of inequitable drainage that has occurred from your lands since your well was completed in the pool, together with details of how the drainage was calculated.	In cases where a well has remained shut in, drainage may be confirmed by summarizing at least two pressure tests taken on the well. If you are arguing that your currently producing well is not producing at sufficient rates to recover an equitable share of production, a comparison may be made between the actual produced volume from the well and the volume the well should have produced to obtain an equitable share of production. You should present a detailed calculation showing how you determined your equitable share of production.
8) A discussion of your proposal as to how the AER should restrict or distribute production from the pool that includes	The AER usually distributes production among wells in a pool on a percentage basis, rather than setting any specific rate or volume. The proportion of production allocated to each well is commonly based on the following formula:

a) a tabulation of the proportion of production or rate of production that each well or group of wells should be allowed to produce, together with the details of how the proposed production scheme was obtained, and

b) if considered appropriate, the total production rate proposed for the pool, together with the details of how this rate was determined and why such a rate should be set, and

c) if specific rates are proposed under item 8(a),

   i) an indication of why rates, rather than a percentage allocation, are being proposed,

   ii) whether the proposed rates are economic for each well or group of wells, and

   iii) whether each well or group of wells would be capable of producing at the proposed rate.

Percentage of pool production for specific well = 100 × (wellbore net pay × porosity × gas saturation × area of spacing unit or validated area for specific well) / (sum of wellbore net pay × porosity × gas saturation × area of spacing units or validated areas for all wells)

Decision 91-8 discusses the AER's commonly used allocation formula and the validated area concept.

The AER has not commonly used mapping as a means to determine hydrocarbon pore volume in a spacing unit because in many cases such mapping is highly interpretative. The AER has not normally factored the deliverability of a well into an allocation formula to avoid disputes on what constitutes appropriate well testing. You may propose an allocation formula other than the commonly used one; however, you should include detailed justification as to why the AER should deviate from its usual practice in determining an allocation formula.

It is not usually necessary to limit the total rate of production (item 8[b]), but this remains an option. In respect of item 8(c), it is not the AER's usual practice to set specific rates, but this also remains an option. In some cases it may be useful to set minimum rates, with a percentage allocation above the minimum rate. If a well falls below the minimum rate, other wells are restricted only to their minimum rates and not below. Items 8(c)(ii) and 8(c)(iii) should be addressed only when there is likely to be a dispute about the economics of a proposed rate or about the capability of a well to produce at a specified rate.

1.2 Application for a Common Purchaser Order

1.2.1 Background

The *Oil and Gas Conservation Act* (the *OGCA*) affords each owner the opportunity of obtaining its share of the production of oil or gas from any pool. Accordingly, the AER may issue a declaration of common purchasers of oil and gas under sections 50(1) and 51(1) of the *OGCA*. Historically the AER has not received applications filed under section 50(1) respecting common purchasers of oil, as the prorationing of oil has been handled under other legislation. However the AER has considered many applications under section 51(1) respecting common purchasers of gas and, accordingly, existing practices primarily deal with the common purchasers of gas.

1.2.2 When to Make This Application

A situation that would warrant the filing of a common purchaser application with the AER would be when the gas reserves associated with a well are being drained by other wells producing in the same pool because the owner of the well cannot obtain a reasonable market for its gas or negotiate a share of the existing markets of other owners with producing wells in the same pool. The well owner has recourse to apply for the declaration of a common purchaser in order to recover its share of gas from the pool.

1.2.3 Terms of Application

An order under sections 50(1) and 51(1) of the *OGCA* obliges each common purchaser, among other things, to purchase production offered for sale to it without discrimination in favour of one producer or another in the same pool. Thus, a common purchaser order would allow an owner that has been unable to obtain its own market to share in the markets obtained by other owners in the pool.

Under section 56 of the *OGCA*, an applicant filing a common purchaser application has the option of requesting that the common purchaser order be effective retroactively to the date of the application. The AER considers such a request in light of the particular situation and has the discretion to grant the request, deny it, or provide some measure of retroactivity other than what was requested.

In order to give effect to a common purchaser order, an applicant filing a request for the declaration of a common purchaser of gas under section 51(1) of the *OGCA* also has the option to request under section 51(4)(a) or (b) that the AER direct

- the point at which the common purchaser shall take delivery of gas offered for sale, and
- the proportion of gas that the common purchaser shall purchase from each producer or owner offering gas for sale.

If there is a dispute as to the price to be paid by the common purchaser for the gas, either the common purchaser or an owner may also apply to the Alberta Utilities Commission (AUC) to set the price under section 55(2). An applicant may choose to file an application for the AUC to set the price of the gas at the same time as it files an application with the AER for the declaration of a common purchaser. However, in most cases where the AER is prepared to grant a common purchaser order, the application for setting the price of the gas is likely to be deferred to allow for additional negotiations.

Usually it would not be necessary for an applicant making a request under section 51(1) for the declaration of a common purchaser to also make requests under each of sections 51(4)(a), 51(4)(b), and 56, although each option is available if there is a dispute on each issue. For example, an application for the declaration of a common purchaser under section 51(1) typically also includes requests under section 51(4)(b) for allocation of production among wells in a pool and under section 56 respecting the effective date of an order. Requests made under sections 51 and 56 should be included in the same application.

1.2.4 How the AER Processes the Application

In evaluating an application for a common purchaser order, the AER considers

- whether drainage has occurred subsequent to the completion of a well on the applicant's property and, if so, to what extent,
- whether opportunities have existed for the marketing of production from the applicant's property and, if so, when and the nature of them,
- future prospects for marketing the production, and
- if application is being made under sections 51(4)(a) or 51(4)(b) for the designation of a delivery point or the proportion of production to be purchased if the applicant could not make reasonable arrangements on these matters.

Each application for a common purchaser order will likely proceed to a public hearing.

1.2.5 Requirements for an Application for a Common Purchaser Order (file 12 copies)

Requirements	Comments
1) A statement of what you are requesting, including a) the purchasers proposed as the common purchasers, b) the pool to which the common purchaser declaration would apply, and c) the proposed effective date of the order.	For example, Company X applies, pursuant to section 51(1) of the *OGCA*, for an order declaring Company Z as a common purchaser of gas produced from the Woodward Viking A Pool. Company X also requests, pursuant to section 56 of the *OGCA*, that the order be effective as of the date of the application and that, pursuant to section 51(4)(b), the AER direct the proportion of gas that the common purchaser shall purchase from each producer or owner offering gas for sale.
2) A statement of whether you are requesting, pursuant to section 51(4) of the *OGCA*, that the AER, to give effect to the common purchaser declaration, direct a) the point at which the common purchaser shall take delivery of gas offered for sale, and/or b) the proportion of gas that the common purchaser shall purchase from each producer or owner offering gas for sale.	
3) A discussion of the reasons why you are requesting the subject order, including a description of the circumstances that in your opinion have led or will lead to an inequitable situation.	

4) Evidence that your well is completed in the pool to which the common purchaser is to apply, including

   a) a net pay isopach map of the pool, including both oil and gas if there is an associated pool;

   The net pay map should show the entire pool and illustrate wells outside the pool that control the edges of the pool.

   b) an interpreted and annotated log cross-section or representative well logs showing

   If there is a dispute among the parties involved regarding the delineation of the pools in question, you should include an annotated cross-section in the application; if there is no dispute, an annotated representative well log is sufficient.

      i) stratigraphic interpretation of the zones of interest,

      ii) interpretation of the fluid interfaces present,

      iii) completions and treatments to the wellbores, with dates,

      iv) cumulative production,

      v) finished drilling date and kelly bushing (KB) elevation, and

      vi) the scale of the log readings; and

   c) a tabulation of the interpreted net pay, porosity, and water saturation for each well in the pool, along with the cutoffs, methodology, formulas, and constants used.

   These data allow the AER to assess your mapping and reserves calculations requested in the following item. In addition, these data may be used to allocate production (see item 13).

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5) Data showing that the well is completed and capable of producing at an economic rate from the pool to which the common purchaser order is to apply.

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6) An evaluation of the oil and gas reserves for the pool and for your lands, including

The reserves estimates confirm that there are reserves available for production.

a) an estimate of the initial oil volume and gas volume in place,

b) an estimate of the oil and gas recovery factors,

c) a description of the methods used in determining (a) and (b) above (i.e., material balance, volumetric analysis, model study, a comparison of analog pools), and

d) the supporting data used in determining (a) and (b) above and the sources of the data (i.e., pressure/volume/temperature [PVT] properties and source, pressure data and source).

You should provide all data used in obtaining the reserves estimates so that your analysis can be duplicated.

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7) A discussion of drainage, including

a) evidence showing that the reserves underlying your lands have been drained subsequent to the completion of your well in the pool,

b) an estimate of the total amount of drainage that has occurred from your lands since your well was completed in the pool, together with details of how the drainage was calculated, and

c) estimates of the present and the expected future rate of drainage of your reserves in the absence of the common purchaser order, together with the details of how the estimates were obtained.

Drainage should be confirmed by summarizing at least two pressure tests obtained from the well.

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8) A discussion of

   a) the opportunities that have existed for the marketing of gas or oil produced from your property, including documentation showing your attempts to obtain a market for your gas or oil, and

   b) the future prospects for marketing the gas or oil.

You should have made substantial efforts to obtain your own markets and to negotiate a voluntary sharing of the existing markets of other owners in the pool. You should apply to the AER only as a last resort. You should also continue your efforts to resolve the matter on a voluntary basis after filing the application with the AER.

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9) A map showing the areas in the pool from which each purchaser purchases gas or oil and the location of your property.

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10) A statement that the proposed common purchaser purchases, produces, or otherwise acquires gas or oil, as the case may be, from the pool containing your property.

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11) If appropriate, a statement specifying the reasons why all the purchasers in the pool are not being proposed as common purchasers.

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12) If you are requesting, pursuant to section 51(4)(a) of the *OGCA*, that the AER, to give effect to the common purchaser declaration, direct the point at which the common purchaser shall take delivery of gas offered for sale to it,

   a) a discussion and documentation indicating what negotiations were carried out in regard to a delivery point and where the impasse lies,

b) a statement of the proposed delivery point, together with a discussion of the reasons why you propose the location,

c) analyses of the economics of the proposed delivery point and alternate delivery points, and

d) a discussion of the development and probable future development in the area.

For each case, the economic analysis should include a detailed itemization of all costs (excluding sunk costs), forecasts of production and revenue streams, and tabulations of before-tax rate of return, payback, and present value analyses.

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13) If you are requesting, pursuant to section 51(4)(b) of the *OGCA*, that the AER, to give effect to the common purchaser declaration, direct the proportion of the common purchaser's acquisitions of gas from the pool that it shall purchase from each producer or owner offering gas for sale,

a) a discussion and documentation indicating what negotiations were carried out in regard to distributing production among wells in the pool and where the impasse lies, and

b) a discussion of your proposal as to how the AER should distribute production from the pool, including a tabulation of the percentage of total production that each well or group of wells should be allowed to produce, together with details of how the proposed scheme was obtained.

The AER's usual practice is to allocate production among wells in a pool on a percentage basis, rather than setting any specific rate or volume. The proportion of production allocated to each well is commonly based on the following formula:

Percentage of pool production for specific well = 100 × (wellbore net pay × porosity × gas saturation × area of spacing unit or validated area for specific well) / (sum of wellbore net pay × porosity × gas saturation × area of spacing units or validated areas for all wells)

Decision 91-8 discusses the AER's commonly used allocation formula and the validated area concept. The AER has not commonly used mapping as a means to determine hydrocarbon pore volume in a spacing unit because in many cases such mapping is interpretive. The AER has not normally factored the deliverability of a well into an allocation formula to avoid disputes on what constitutes appropriate testing of wells.

You may propose an allocation formula other than the commonly used one; however, you should include detailed justification as to why the AER should deviate from its usual practice in determining an allocation formula.

In some cases it may be useful to set minimum rates, with a percentage allocation above the minimum rate. If a well falls below the minimum rate, other wells are restricted only to their minimum rates and not below.

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14) If you are requesting, pursuant to section 56 of the *OGCA*, that the proposed order be effective prior to the date the order is issued but not prior to the date the application for the order was made to the AER, a discussion as to why the order should be effective on the requested date, including

    a) the steps that you have taken to market your production, and

    b) an indication of whether or not your well is tied into a gathering system and, if not, why the order should be made on a retroactive basis.

1.3 Application for a Common Carrier Order

1.3.1 Background

The *Oil and Gas Conservation Act* (*OGCA*) affords each owner the opportunity of obtaining its share of the production of oil or gas from any pool and provides for economic, orderly, and efficient development in the public interest. Accordingly, the AER may issue a declaration of a common carrier of oil, gas, or synthetic crude oil under section 48 of the *OGCA*.

The common carrier provisions of the *OGCA* cannot be used to gain access to an oil battery, as indicated in the AER letter of October 26, 2005, respecting Application No. 1398650.

1.3.2 When to Make This Application

A typical situation that would warrant the filing of a common carrier application with the AER would be when an owner of a capable well has a market for its gas and has made arrangements to have the gas processed at a nearby plant. Its analysis shows the existing gathering system to be the only economically feasible way, the most practical way to transport the substance in question, or clearly superior environmentally for transporting its gas to the processing plant. However, the owner has been unsuccessful in negotiating an agreement on reasonable terms to use the existing pipeline. The well owner has recourse to apply for the declaration of a common carrier in order to obtain its share of gas from the pool.

1.3.3 Terms of Application

An order under section 48 of the *OGCA* obliges each common carrier, among other things, to transport production without discrimination as between any of the owners for whom transportation is provided. Thus, a common carrier order would allow an owner to share in the existing capacity of the pipeline.

Under section 56 of the *OGCA*, an applicant filing a common carrier application has the option of requesting that the common carrier order be effective retroactively to the date of the application. The AER considers such a request in light of the particular situation and has the discretion to grant the request, deny it, or provide some measure of retroactivity other than what was requested.

In order to give effect to a common carrier order, an applicant filing a request for the declaration of a common carrier under section 48(1) of the *OGCA* also has the option to request that the AER direct

- the point at which the common carrier shall take delivery of the production (section 48(4)(a)), and
- the proportion of production to be taken by the common carrier from each producer or owner offering production to be gathered, transported, handled, or delivered by means of a pipeline (section 48(4)(b)).

If there is a dispute as to the tariff to be paid to the common carrier, either the common carrier or an owner may also apply to the Alberta Utilities Commission (AUC) to set the price under sections 55(1) or 55(3) of the *OGCA*. An applicant may choose to file an application with the AUC to set tariffs at the same time as it files an application under section 48. However, in most cases where the AER is prepared to grant a common carrier order, the application for the setting of tariffs may be deferred to allow for additional negotiations.

Usually it would not be necessary for an applicant making a request under section 48(1) of the *OGCA* for the declaration of a common carrier to also make requests under each of sections 48(4)(a), 48(4)(b) and 56, although each option is available if there is a dispute on each issue. For example, an application for the declaration of a common carrier under section 48(1) typically also includes requests under section 48(4)(b) for allocation of production among wells in a pool and under section 56 respecting the effective date of an order. Requests under sections 48 and 56 should be included in the same application.

1.3.4 How the AER Processes the Application

In evaluating an application for a common carrier order, the AER considers whether the applicant has demonstrated that

- producible reserves are available for transportation through an existing pipeline,
- there is a reasonable expectation of a market for the substance that is proposed to be transported by the common carrier operation,
- the applicant could not make reasonable arrangements to use the existing pipeline,
- the proposed common carrier operation is the only economically feasible way, the most practical way to transport the substance in question, or clearly superior environmentally, and
- where application is being made under sections 48(4)(a) or 48(4)(b) of the *OGCA* for the designation of a delivery point or the proportion of production to be delivered to the pipeline the applicant could not make reasonable arrangements on these matters.

Each common carrier application will likely proceed to a public hearing.

1.3.5 Requirements for an Application for a Common Carrier Order (file 12 copies)

Requirements	Comments
1) A statement of what is being requested, including a) a reference that you are making the application under section 48 of the *OGCA*, b) the name of the company to be designated as the common carrier, c) reference to the pool or pools to which the proposed common carrier declaration would apply, or if it is proposed that the order not apply to any specific pool, a discussion as to why the order should not apply to a specific pool or pools, d) the location of the pipelines to which the proposed common carrier order would apply, including the proposed tie-in and terminating points, and e) the proposed effective date of the order.	For example, Company X applies under section 48 of the *OGCA* for an order declaring Company Z to be a common carrier of gas produced from the Woodward Viking A Pool through a pipeline extending from LSD x to LSD y and including a field compressor located in LSD z. Company X also requests, pursuant to section 56 of the *OGCA*, that the order be effective as of the date of the application and that, pursuant to section 48(4)(b) of the *OGCA*, the AER direct the proportion of production to be taken by the common carrier from each producer or owner.
2) A statement of whether you are requesting, pursuant to section 48(4) of the *OGCA*, that the AER, to give effect to the common carrier declaration, direct a) the point at which the common carrier shall take delivery of production, and/or b) the proportion of production to be taken by the common carrier from each producer or owner.	See comments for items 13, 14, and 16.

3) A discussion giving the reasons why you are requesting the subject order, including a description of the circumstances that in your opinion have led or will lead to an inequitable situation.	
4) Documentation showing that reasonable arrangements for the use of the pipeline could not be agreed upon, including a) identification of all parties involved and the nature of their issues and concerns, and	You should have made substantial efforts to negotiate a resolution to the matter prior to filing an application with the AER. The application should be a last resort. You should also continue your efforts to resolve the matter on a voluntary basis (including consideration of a third-party mediator) after filing the application with the AER.
b) an outline of the attempts to resolve the issues, including type of discussions held, timing, and frequency.	Your discussion must include the reasons why the negotiations did not lead to a settlement and what dispute resolution efforts were conducted. Matters of confidentiality and disclosure should be addressed and determined by the parties prior to submission of the application. The documentation should illustrate your case that you have been unable to obtain reasonable arrangements. Matters of dispute may include access on terms that would allow you to obtain your share of production from the pool at reasonable fees.
5) A statement specifying the operator and ownership of the pipeline to be subject to the proposed order.	
6) An indication of the available capacity of the pipeline to be subject to the proposed common carrier order.	

7) A map showing the location of the subject pool, pipelines, any alternative facilities, and your production facilities.

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8) Your geological interpretation of the pool involved, including

   a) a net pay isopach map of the pool, including both oil and gas if there is an associated pool;

   The net pay map should show the entire pool and illustrate wells outside the pool that define the edges of the pool.

   b) where pool delineation or fluid interfaces are based on structural interpretation, a structure contour map of the pool and offsetting area;

   c) an interpreted and annotated log cross-section or representative well logs showing

      i) stratigraphic interpretation of the zones of interest,

      ii) interpretation of the fluid interfaces present,

      iii) completions and treatments to the wellbores, with dates,

      iv) cumulative production,

      v) finished drilling date and kelly bushing (KB) elevation, and

      vi) the scale of the log readings; and

   If there is a dispute among the parties involved regarding the delineation of the pools in question, you should include an annotated cross-section in the application; where there is no dispute respecting this issue, an annotated representative well log is sufficient.

   d) a tabulation of the interpreted net pay, porosity, and water saturation for each well in the pool, along with the cutoffs, methodology, formulas, and constants used.

   These data assist the AER to assess your mapping and reserves calculations requested in the following item. In addition, these data may be used to allocate production (see item 14).

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9) An evaluation of the oil and gas reserves for the pool and for your lands, including

   a) an estimate of the initial oil volume and gas volume in place,

   b) an estimate of the oil and gas recovery factors,

   c) a description of the methods used in determining (a) and (b) above (e.g., material balance, volumetric analysis, model study, a comparison of analog pools), and

   d) the supporting data used in determining (a) and (b) above and the sources of the data (i.e., pressure/volume/temperature [PVT] properties and source, pressure data and source).

The reserves estimates confirm that there are reserves available for production.

You should provide all data used in obtaining the reserves estimates so that your analysis can be duplicated.

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10) A discussion of drainage, including

   a) evidence showing that the reserves underlying your lands have been drained subsequent to the completion of your well in the pool, and

   b) an estimate of the total amount of inequitable drainage that has occurred from your lands since your well was completed in the pool, together with details of how the drainage was calculated.

Drainage is not a prerequisite for the issuance of a common carrier order but could be one factor in determining the need for an order. In addition, the AER would consider the extent to which drainage has occurred in evaluating what the effective date of the order should be.

In cases where a well has remained shut in, you may confirm drainage by summarizing a minimum of two pressure tests taken on the well. If you are arguing that your currently producing well is not producing at sufficient rates to recover an equitable share of production, you may make a comparison between the actual produced volume from the well and the volume the well should have produced to obtain an equitable share of production. You should present a detailed calculation showing how you determined your equitable share of production.

11) A discussion of the practicability, economics, and any environmental concerns of

   a) the proposed common carrier operation,

   b) the alternative of building new facilities,

   c) the alternative of using other facilities (such as taking the gas to another existing plant), and

   d) any other alternatives available.

For each case, the economic analysis should include a detailed itemization of all costs used (excluding sunk costs), forecasts of production and revenue streams, and tabulations of before-tax rate of return, payback, and present value analyses.

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12) A discussion of the availability or the reasonable expectation of a market for the oil, gas, or synthetic crude oil that would be transported in the common carrier operation.

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13) If you are requesting, pursuant to section 48(4)(a) of the *OGCA*, that the AER, to give effect to the common carrier declaration, direct the point at which the common carrier shall take delivery of any production to be gathered, transported, handled, or delivered by means of the subject pipeline,

   a) a discussion and documentation indicating what negotiations were carried out in regard to a delivery point and where the impasse lies,

   b) a statement of the proposed delivery point, together with a discussion of the reasons why you propose the location,

c) analyses of the economics of the proposed delivery point and alternative delivery points, and

d) a discussion of the development and probable future development in the area.

For each case, the economic analysis should include a detailed itemization of all costs (excluding sunk costs), forecasts of production and revenue streams, and tabulations of before-tax rate of return, payback, and present value analyses.

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14) If you are requesting, pursuant to section 48(4)(b) of the *OGCA*, that the AER, to give effect to the common carrier declaration, direct the proportion of production to be taken by the common carrier from each producer or owner offering production to be gathered, transported, handled, or delivered by means of the subject pipeline,

a) a discussion and documentation indicating what negotiations were carried out in regard to distributing production among wells in the pool and where the impasse lies, and

b) a discussion of your proposal as to how the AER should distribute production from the pool that includes a tabulation of the proportion or percentage of total production that each well or group of wells should be allowed to produce, together with the details of how the proposed production scheme was obtained.

The AER's usual practice is to allocate production among wells in a pool on a percentage basis, rather than setting any specific rate or volume. The proportion of production allocated to each well is commonly based on the following formula:

Percentage of pool production for specific well = 100 × (wellbore net pay × porosity × gas saturation × area of spacing unit or validated area for specific well) / (sum of wellbore net pay × porosity × gas saturation × area of spacing units or validated areas for all wells)

Decision 91-8 discusses the AER's commonly used allocation formula and the validated area concept. The AER has not generally used mapping as a means to determine hydrocarbon pore volume in a spacing unit because in many cases such mapping is highly interpretive. The AER has not normally factored the deliverability of a well into an allocation formula to avoid disputes on what constitutes appropriate testing of wells. You may propose an allocation formula other than the commonly used one; however, you should offer detailed justification as to why the AER should deviate from its consistent practice in determining an allocation formula.

In some cases it may be useful to set minimum rates, with a percentage allocation above the minimum rate. If a well falls below the minimum rate, other wells are restricted only to their minimum rates and not below.

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15) If you are requesting, pursuant to section 56 of the *OGCA*, that the proposed order be effective prior to the date the order is issued but not prior to the date the application for the order was made to the AER, a discussion as to why the order should be effective on the requested date, including

    a) the steps that you have taken to market your production, and

    b) an indication of whether your well is tied into a gathering system and, if not, why the order should be made on a retroactive basis.

1.4 Application for a Common Processor Order

1.4.1 Background

The *Oil and Gas Conservation Act* (*OGCA*) affords each owner the opportunity of obtaining its share of the production of oil or gas from any pool and provides for economic, orderly, and efficient development in the public interest. Accordingly, the AER may issue a declaration of a common processor of gas under section 53 of the *OGCA*.

1.4.2 When to Make This Application

A typical situation that would warrant the filing of a common processor application with the AER would be when an owner of a capable well has a market for its gas requiring processing to meet contract specifications. The owner believes that using the existing plant is the only economically feasible or most practical way to process the gas in question or is clearly superior environmentally, but the owner has been unsuccessful in negotiations to gain access to the plant on reasonable terms. The owner has recourse to apply for the declaration of a common processor in order to gain access to the plant and allow it to obtain its share of gas from the pool.

1.4.3 Terms of Application

An order under this section obliges each common processor, among other things, to process gas that may be made available for processing in the plant without discrimination in favour of one producer or owner as against another in the pool.

Under section 56 of the *OGCA*, an applicant filing a common processor application has the option of requesting that the common processor order be effective retroactively to the date of the application. The AER considers such a request in light of the particular situation and has the discretion to grant the request, deny it, or provide some measure of retroactivity other than that requested.

In order to give effect to a common processor order, an applicant filing a request for the declaration of a common processor also has the option of requesting that the AER direct

- the proportion of production to be processed by the common processor from each producer or owner in the pool (section 53[5][a]), and/or
- the total amount of gas to be processed by the common processor from the pool subject to the common processor declaration (section 53[5][b]).

If there is a dispute as to the tariff to be paid to the common processor, either the common processor or an owner may also apply under section 55(2) of the *OGCA* to the Alberta Utilities Commission (AUC) to set the price.

An applicant may choose to file an application with the AUC to set fees at the same time as it files an application under section 53. However, in most cases where the AER is prepared to grant a common processor order, the application for the setting of tariffs may be deferred to allow for additional negotiations.

Usually it would not be necessary for an applicant making a request under section 53(1) for the declaration of a common processor to also make requests under each of sections 53(5)(a), 55(2), and 56, although each option is available if there is a dispute on each issue. For example, an application for the declaration of a common processor under section 53(1) typically also includes requests under section 53(5)(a) for allocation of production among wells in a pool and under section 56 respecting the effective date of an order. Requests under sections 53 and 56 should be included in the same application.

1.4.4 How the AER Processes the Application

In evaluating an application for a common processor order, the AER considers whether the applicant has demonstrated that

- producible reserves are available for processing and processing facilities are needed,
- reasonable arrangements for use of processing capacity in the subject processing plant could not be agreed upon by the parties,
- the proposed common processor operation is either the only economically feasible or most practical way to process the gas in question or is clearly superior environmentally, and
- when an application is being made under sections 53(5)(a) or 53(5)(b) of the *OGCA* for the allocation of production or a direction of the total volume of gas from the pool to be processed at the plant the applicant could not make reasonable arrangements on these matters.

Each application for a common processor order will likely proceed to a public hearing.

1.4.5 Requirements for an Application for a Common Processor Order (file 12 copies)

Requirements	Comments
1) A statement of what is being requested, including a) a reference that you are making the application under section 53 of the *OGCA*, b) the name of the company to be designated as the common processor, c) a reference to the pool or pools to which the proposed common processor declaration would apply, d) the name and the location of the processing plant to which the proposed common processor order would apply, and e) the proposed effective date of the order.	For example, Company X applies under section 53 of the *OGCA* for an order declaring Company Z to be a common processor of gas produced from the Woodward Viking A Pool through the Grande Coulee Gas Plant located at LSD. Company X also requests, pursuant to section 56 of the *OGCA*, that the order be effective as of the date of the application and that, pursuant to section 53(5)(a) of the *OGCA*, the AER direct the proportion of production to be taken by the common processor from each producer or owner in the Woodward Viking A Pool.
2) A statement of whether you are requesting, pursuant to section 53(5) of the *OGCA*, that the AER, in order to give effect to the common processor declaration, direct a) the proportion of production to be processed by the common processor from each producer or owner in the pool or pools, and/or b) the total amount of gas to be processed by the common processor from the pool or pools subject to the common processor declaration.	See comments for items 14, 15, and 17.

3) A discussion giving the reasons why you are requesting the order, including a description of the circumstances that in your opinion have led or will lead to an inequitable situation.

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4) Documentation showing that reasonable arrangements for the use of processing capacity in the plant could not be agreed upon, including

   a) identification of all parties involved and the nature of their issues and concerns, and

   b) an outline of the attempts to resolve the issues, including type of discussions held, timing, and frequency.

You should have made substantial efforts to negotiate a resolution to the matter prior to filing an application with the AER. The application should be a last resort. You should also continue your efforts to resolve the matter on a voluntary basis (including consideration of a third-party mediator) after you have filed the application with the AER.

Your discussion must include the reasons why the negotiations did not lead to a settlement and what dispute resolution efforts were conducted. Matters of confidentiality and disclosure should be addressed and determined by the parties prior to submission of the application.

The documentation should illustrate your case that you have been unable to obtain reasonable arrangements. Matters of dispute may include access on terms that would allow you to obtain your show or production from the pool at reasonable tariffs.

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5) A map showing the location of the subject pool, processing plant, any alternative facilities, and your production facilities.

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6) A statement specifying the operator and ownership of the processing plant.

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7) A discussion of

   a) the total processing capacity of the plant,

   b) the volumes of gas from the pool or pools to be subject to the proposed common processor declaration and from other pools currently processed at the subject plant, and

   c) the processing capacity available to you in the plant.

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8) An analysis of the composition of the gas to be processed under the common processor declaration, together with a discussion as to the capability of the plant to process the subject gas.

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9) Your geological interpretation of the pool involved, including

   a) a net pay isopach map of the pool, including both oil and gas if there is an associated pool;

   The net pay map should show the entire pool and illustrate wells outside the pool that control the edges of the pool.

   b) where pool delineation or fluid interfaces are based on structural interpretation, a structure contour map of the pool and offsetting area;

   c) an interpreted and annotated log cross-section or representative well logs showing

      i) stratigraphic interpretation of the zones of interest,

      ii) interpretation of the fluid interfaces present,

   If there is a dispute among the parties involved regarding the delineation of the pools in question, you should include an annotated cross-section in the application; if there is no dispute respecting this issue, an annotated representative well log is sufficient.

iii) completions and treatments to the wellbores, with dates,

iv) cumulative production,

v) finished drilling date and kelly bushing (KB) elevation, and

vi) the scale of the log readings; and

d) a tabulation of the interpreted net pay, porosity, and water saturation for each well in the pool, along with the cutoffs, methodology, formulas, and constants used.

These data assist the AER to assess your mapping and reserves calculations requested in the following item. In addition, the data may be used to allocate production (see item 14).

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10) An evaluation of the oil and gas reserves for the pool and for your lands, including

The reserve estimates confirm that there are reserves available for production.

a) an estimate of the initial oil volume and gas volume in place,

b) an estimate of the oil and gas recovery factors,

c) a description of the methods used in determining (a) and (b) above (e.g., material balance, volumetric analysis, model study, a comparison of analog pools), and

d) the supporting data used in determining (a) and (b) above and the sources of the data (e.g., pressure/volume/temperature [PVT] properties and source, pressure data and source).

You should provide all data used in obtaining the reserves estimates so that your analysis can be duplicated.

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11) A discussion of drainage, including a) evidence showing that the reserves underlying your lands have been drained subsequent to the completion of your well in the pool, and b) an estimate of the total amount of inequitable drainage that has occurred from your lands since your well was completed in the pool, together with details of how the drainage was calculated.	Drainage is not a prerequisite for the issuance of a common processor order but could be one factor in determining the need for an order. In addition, the AER considers the extent to which drainage has occurred in evaluating what the effective date of the order should be. In cases where a well has remained shut in, you can confirm drainage by summarizing a minimum of two pressure tests taken on the well. If you are arguing that your currently producing well is not producing at sufficient rates to recover an equitable share of production, you may make a comparison between the actual produced volume from the well and the volume the well should have produced to obtain an equitable share of production. You should present a detailed calculation showing how you determined your equitable share of production.
12) A discussion of the practicability, economics, and any environmental concerns of a) the proposed common processor operation, b) the alternative of building new facilities, c) the alternative of using other facilities (such as taking the gas to another existing plant), and d) any other alternatives available.	For each case, the economic analysis should include a detailed itemization of all costs (excluding sunk costs), forecasts of production and revenue streams, and tabulations of before-tax rate of return, payback, and present value analyses.
13) A discussion of the availability or the reasonable expectation of a market for your gas that would be processed at the plant.	

14) If you are requesting, pursuant to section 53(5)(a) of the *OGCA*, that the AER, in order to give effect to the common processor declaration, direct the proportion of production to be processed by the common processor from each producer or owner in the pool or pools,

    a) a discussion and documentation indicating what negotiations were carried out in regard to distributing production among wells in the pool and where the impasse lies, and

    b) a discussion of your proposal as to how the AER should distribute production from the pool, including a tabulation of the proportion or percentage of total production that each well or group of wells should be allowed to produce, together with the details of how the proposed production scheme was obtained.

The AER's usual practice is to allocate production among wells in a pool on a percentage basis, rather than setting any specific rate or volume. The proportion of production allocated to each well is commonly based on the following formula:

> Percentage of pool production for specific well = 100 × (wellbore net pay × porosity × gas saturation × area of spacing unit or validated area for specific well) / (sum of wellbore net pay × porosity × gas saturation × area of spacing units or validated areas for all wells)

Decision 91-8 discusses the AER's commonly used allocation formula and the validated area concept. The AER has not generally used mapping as a means to determine hydrocarbon pore volume in a spacing unit because in many cases such mapping is highly interpretive. The AER has not normally factored the deliverability of a well into an allocation formula to avoid disputes on what constitutes appropriate testing of wells. You may propose an allocation formula other than the commonly used one; however, you should offer detailed justification as to why the AER should deviate from its consistent practice in determining an allocation formula.

In some cases it may be useful to set minimum rates, with a percentage allocation above the minimum rate. If a well falls below the minimum rate, other wells are restricted only to their minimum rates and not below.

15) If you are requesting, pursuant to section 53(5)(b) of the *OGCA*, that the AER, in order to give effect to the common processor declaration, direct the total amount of gas to be processed by the common processor from the pool or pools subject to the common processor declaration,

   a) a statement of why you believe such a total volume should be set,

   b) a discussion and documentation indicating what negotiations were carried out in regard to the total amount of gas to be processed by the common processor from the pool or pools subject to the common processor declaration and where the impasse lies, and

   c) a statement of the total amount of gas you propose be processed by the common processor from the pool or pools subject to the common processor, together with a discussion of how the volume was determined.

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16) If you are requesting, pursuant to section 56 of the *OGCA*, that the proposed order be effective prior to the date the order is issued but not prior to the date the application for the order was made to the AER, a discussion as to why the order should be effective on the requested date, including

   a) the steps that you have taken to market your production and

   b) an indication of whether your well is tied into a gathering system and, if not, why the order should be made on a retroactive basis.

1.5 Application for a Compulsory Pooling Order

1.5.1 Background

Section 4.021 of the *Oil and Gas Conservation Rules* specifies that no well shall be produced unless there is common ownership throughout the drilling spacing unit (DSU). This means that if there are separate tracts within a DSU with different ownership, all owners within the DSU must have an arrangement to share in the costs and revenues associated with drilling and producing a well from that spacing unit. This type of arrangement is generally referred to as a pooling agreement. In most cases, mineral holders negotiate voluntary pooling arrangements. However, if an owner attempts but fails to negotiate a satisfactory pooling arrangement in a reasonable period of time, or a tract owner is missing and untraceable, or there is a dispute as to the ownership of a tract, the owner wishing to drill a well may apply to the AER for a compulsory pooling order. This order serves the same purpose as a voluntary pooling arrangement by ensuring that each owner in the DSU shares appropriately in the costs and revenues associated with a well in the DSU.

The AER's role in pooling matters, therefore, is to offer a regulatory avenue to resolve problems relating to pooling issues, thereby allowing each owner the opportunity to obtain its share of oil and gas from any pool.

Applications for compulsory pooling are made

- under section 80 of the *Oil and Gas Conservation Act* (*OGCA*);
- if there is a missing and untraceable owner in the spacing unit, under both sections 80 and 85 of the *OGCA* (section 85 provides that the revenues associated with the missing and untraceable owner be paid to the Public Trustee); and
- if there is a dispute as to the ownership of a tract or ownership is unknown, under both sections 80 and 86 of the *OGCA* (section 86 provides that revenues associated with the disputed tract be paid to the Provincial Treasurer to be held in trust pending an order of the Court of Queen's Bench or until a settlement has been reached by the parties).

The AER's current policies and practices respecting pooling arise from a combination of specific provisions of the *OGCA*, historical decisions made by the AER, consultations with industry, and AER decisions resulting from pooling applications considered at public hearings. These avenues have resulted in an AER pooling order with standard terms. Nonstandard terms are included in an order only if there is substantial justification to do so. General information on major AER policies and practices respecting pooling and the standard terms of a pooling order are noted below in the Requirements sections. More detailed information can be obtained from AER staff.

1.5.2 How the AER Processes the Application

AER staff initially review a pooling application for completeness. If additional information is required, a letter is issued itemizing the information required. Processing of the application is deferred pending receipt of the requested information.

Except in cases involving missing and untraceable owners or minor amendments to existing pooling orders, once an application is complete the AER normally issues a notice of application. The notice of application would not usually be published in any newspapers but would be sent directly to parties with an interest in the petroleum and/or natural gas underlying the DSU. Interested parties would have a specified time period in which to file any submissions they may have respecting the application.

If no submissions are received in response to the notice of application, the AER makes a decision on the application without further notice or a hearing. If a submission is filed in response to the notice of hearing, the scheduled hearing will likely proceed and the AER will consider the application and the filed submissions.

1.5.3 Requirements for an Application for a Compulsory Pooling Order (file 12 copies)

Requirements

1) A statement of what you are requesting, including

   a) a reference to the sections of the *OGCA* under which you are making the application, and

   b) the legal description of the DSU involved.

Comments

You should cite section 80 of the *OGCA* and, if applicable, sections 85 or 86. For example: Company X is applying for a compulsory pooling order for the production of gas under section 80 of the *OGCA* in the DSU constituting Section 13-45-12W4M.

The size of the DSU involved should be consistent with the substance to be pooled (oil or gas). Thus, oil would normally be pooled within a standard oil DSU of a quarter section, while gas would be pooled within a standard gas DSU of one section.

Compulsory pooling occurs only within a single DSU. Section 80 of the *OGCA* does not allow for compulsory pooling within several DSUs.

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2) A statement providing the legal description of each tract within the DSU and the ownership of that tract, together with a table showing the mailing addresses for all lessors and lessees (except the Crown).

For example, for the gas DSU constituting Section 13-45-12W4M:

Ownership			
Tract	**Lessor**		**Lessee**
SW quarter	Crown		Company A
SE quarter	Freehold	1/2 undivided I. Doe	Company A
		1/2 undivided P. Doe	Not leased
North half	Freehold	Company B	Company A

You should provide the mailing addresses of all lessors (except the Crown) and lessees as an attachment to the application. This allows the AER to provide notice of the application to all potentially adversely affected parties.

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3) A statement of the formation to which you propose to drill or from which you propose to produce.	The formation subject to the pooling order would be cited in the order. In previous pooling applications where there has been a dispute about which formations should be subject to a pooling order, the AER decided to limit the formation subject to the order to the known productive zone or to the major productive zone (*Examiner Reports 91-6* and *95-2*).
4) A statement that an agreement to operate the tracts as a unit cannot be made on reasonable terms.	
5) The particulars of the efforts you have made to obtain a voluntary agreement, including a) identification of all parties involved and the nature of their issues and concerns, b) an outline of the attempts to resolve the issues, including type of discussions held, timing, and facilities, and c) an indication of your view of why attempts to obtain a voluntary pooling arrangement have failed in each case.	You should have made substantial efforts to negotiate a voluntary pooling arrangement. The application should be a last resort. You should also continue your efforts to resolve the matter on a voluntary basis (including considerations of a third-party mediator) after filing the application with the AER. Your discussion must include the reasons why the negotiations did not lead to a settlement and what dispute resolution efforts were conducted. Matters of confidentiality and disclosure should be addressed and determined by the parties prior to submission of the application. A description of your efforts to resolve the situation should include a summary of telephone calls and meetings and copies of relevant correspondence.
6) If there is a well on the DSU that is to be produced under the proposed pooling order, a statement of the unique identifier of the well and its producing formation or formations.	The well to be subject to the pooling order would be cited in the pooling order.

7) If there is not a well on the DSU drilled to the formations referred to in item 3, a statement indicating the location (LSD) of the well to be drilled.	The proposed well location would be included in the pooling order.
8) If there is not a well on the DSU drilled to the formations referred to in item 3, a statement that if an order is made by the AER, you are prepared to drill a well to the formations in question, and in the event that no production of gas or oil is obtained, you will pay all costs incurred in the drilling and abandonment of the well in accordance with section 80(2)(f) of the *OGCA*.	
9) If there is not a well drilled on the DSU, an indication of whether you would see any difficulty in drilling the well within six months of the date of the proposed order if issued, and if so, an indication of what would be a more appropriate time limit to drill.	Section 82(2) of the *OGCA* implies that a well should be drilled within six months of the date of the order.
10) A statement of the operator to be appointed for the well of interest in the proposed pooling order.	All pooling orders normally include a clause that names the operator of the well subject to the pooling order.
11) A statement that the allocation of costs and revenues under the pooling order would be on a tract area basis, or if allocation is proposed to be on a basis other than an area basis, the proposed allocation and the details of how the allocation was determined, including	Section 80(4)(c) of the *OGCA* indicates that allocation shall be on an area basis unless it can be shown to the AER that this is inequitable. Thus, allocation on an area basis is the normal provision of a pooling order, and an applicant would not need to justify why it has chosen to request an area-based allocation.

a) a net pay isopach map of the pool, including both oil and gas if there is an associated pool;

b) if pool delineation or fluid interfaces are based on structural interpretation, a structure contour map of the pool and offsetting area;

c) an interpreted and annotated log cross-section or representative well logs showing

    i) stratigraphic interpretation of the zones of interest,

    ii) interpretation of the fluid interfaces present,

    iii) completions and treatments to the wellbores, with dates,

    iv) cumulative production,

    v) finished drilling date and kelly bushing (KB) elevation, and

    vi) the scale of the log readings, and

d) a tabulation of the interpreted net pay, porosity, and water saturation for each well in the pool, along with the cutoffs, methodology, formulas, and constants used.

If there is a dispute among the parties involved regarding the delineation of the pools in question, you should include an annotated cross-section in the application; if there is no dispute respecting this issue, an annotated representative well log is sufficient.

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12) A statement indicating whether you are proposing that the requested order provide for the equalization of the actual cost of drilling the well to and completing it in the formations named in the pooling order, in accordance with section 80(4)(d) of the *OGCA*.

This is a standard provision of a typical pooling order. It applies to a situation where an applicant has itself drilled a well for the purpose of producing the zone to be subject to the pooling order or is proposing to drill such a well.

If the case is not the standard one—for example, if a well was drilled and produced from a zone other than the one to be subject to the pooling order—it would normally be appropriate to modify the standard provision such that not all original drilling and completion costs would be shared.

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13) A statement as to whether you are proposing that the requested order provide for a penalty to be imposed against actual drilling and completion costs in accordance with section 80(5) of the *OGCA* and, if so,

    a) what penalty should be imposed,

    b) the justification for the proposed penalty, and

    c) confirmation that in accordance with normal AER practice, you would agree that the proposed penalty would be applied if the tract owner did not pay its share of actual drilling and completion costs within 30 days of the pooling order being issued, the well commencing production, and the tract owner being notified in writing of its share of costs, whichever is later; or if you are proposing an alternative to the AER's normal practice, a justification of why the AER should depart from its normal practice in this case.

A penalty under section 80(5) of the *OGCA* is a standard provision of pooling orders involving disputes between industry players. In these cases, the AER has normally provided for the maximum penalty allowed by section 80(5). That is, if the maximum penalty applies and a tract owner has chosen to incur the penalty rather than pay costs "up front," the tract owner would owe the well operator its share costs plus the penalty of two times the cost. If the tract owner's share of costs were $10 000 and it chose to incur the penalty, it would pay costs of $10 000 plus two times the costs, equalling $20 000, for a total of $30 000.

1.6 Special Drilling Spacing Unit

[Rescinded]

Unit 2 Conservation

2.1 Application for an Enhanced Recovery Scheme

2.1.1 Introduction

2.1.1.1 Background

Enhanced recovery (ER) improves hydrocarbon recovery by injecting fluids into a hydrocarbon reservoir to

- add to or maintain reservoir energy (pressure),
- displace hydrocarbons to production wells, and/or
- alter the reservoir fluids so that hydrocarbon flow and recovery are improved.

An application to implement or amend an ER scheme is required in accordance with section 39(1)(a) of the *Oil and Gas Conservation Act* (*OGCA*). Additional approvals from the AER or other government agencies may also be required to implement an ER scheme.

If changes to an existing ER scheme approval are required, an application must be made for the appropriate amendments.

2.1.1.2 Application Process

A) How to Make an ER Scheme Application

Apply for an ER scheme application using the enhanced recovery scheme application form found in appendix F. This form, together with Schedule 1 and the required attachments, constitute the "complete application" prescribed by section 2.1.3.3.

Submit the information electronically using the Electronic Application Submission (EAS) process accessed through the Digital Data Submission (DDS) screen on the AER's website, www.aer.ca. The AER will validate all applications to ensure that the requirements for ER schemes have been met. Incomplete applications or those containing significant errors will be closed.

This application process does not apply to crude bitumen ER schemes in the oil sands areas. An application for these schemes must comply with the *Oil Sands Conservation Act* (section 10 for new schemes, or section 13 for an amendment to an existing scheme).

Wells proposed as injectors on an enhanced recovery scheme do not necessarily have to be drilled before submitting an enhanced recovery scheme application. If the injection well has not yet been drilled, an optional two-step pre-drill application process is available. This process allows operators to receive a conditional approval before the drilling of the wells. If the application for the scheme is approved, the process will provide information on the possible approval conditions before an investment decision is made by the applicant. This process, in the context of enhanced oil recovery schemes, is only recommended where conditions exist that may lead to some uncertainty as to the regulatory restrictions that may be imposed on an injection well location. Further details regarding the pre-drill process are outlined in the application process guidelines on the AER's website.

If the pre-drill application process is not used, the regular enhanced recovery application process must be used, which requires that the proposed injection wells be drilled before application. Notifications, as required in tables 1–3, are normally valid for two years, and renotification may be required if the ownership structures and potentially affected parties change in the interim.

The AER will permit, without application, a maximum cumulative water injection of 500 m^3 in order to acquire the information required under *Directive 051: Injection and Disposal Wells – Well Classifications, Completions, Logging, and Testing Requirements* and to determine the maximum wellhead injection pressure (MWHIP).

B) How the AER Processes the Application

The AER reviews all ER scheme applications to ensure that hydrocarbon recovery will be optimized and that all ER scheme requirements are met. ER scheme applications meeting the base criteria detailed in figure 2.1 will be processed in an expedited manner under a quick ER application process.

Applications qualifying for the quick process will be processed in a way that shifts the review emphasis from scheme design (application) to scheme performance (audit). Applications not meeting these base criteria will require a more detailed review addressing those areas in which the criteria are not met.

The AER will issue its disposition of ER scheme applications electronically, with the disposition being available for viewing through IAR Query for 30 days after the disposition of the application. IAR Query is accessible via the Systems and Tools portal on the AER's website.

The *Directive 051* application for all injection wells can be submitted at any time before or after the *Directive 065* ER scheme application. Submit the *Directive 065* and *Directive 051* applications through the DDS system. All injection wells must meet the initial and subsequent *Directive 051* requirements.

Injection operations that contain fluids with any H_2S must meet the requirements of *Directive 071: Emergency Preparedness and Response Requirements for the Petroleum Industry*. Also, if an injection fluid contains H_2S, all pipelines and facilities associated with the scheme must be approved for the appropriate sour service as directed by *Directive 056: Energy Development Applications and Schedules*.

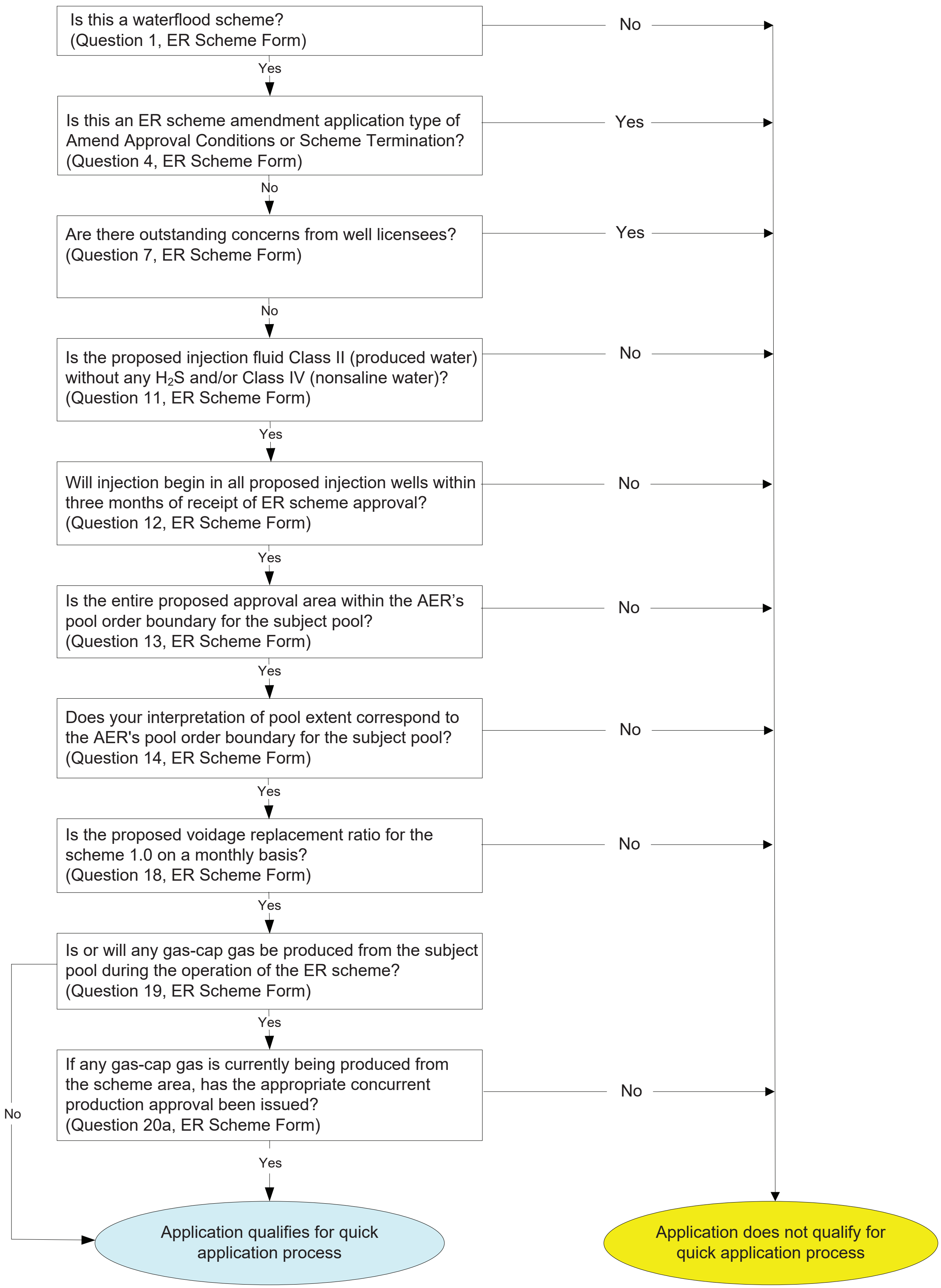

Figure 2.1 Decision tree for the quick enhanced recovery application process

Before submitting an ER scheme application, ensure pool delineation differences that are pertinent to the ER scheme design are resolved by a separate pool delineation application, in accordance with section 2.5 of this directive, so there are no differences between the applicant's and the AER's interpretation of pool delineation pertinent to the ER scheme. An exception may be if the proposed approval area is larger than the pool order boundary due to wells not yet evaluated by the AER.

2.1.1.3 Other Issues

A) Allowable Administration

For oil pools on maximum rate limitation (MRL) administration, upon approval of a new ER scheme or ER scheme amendment, good production practice (GPP) will normally be granted to the wells within the approval area. If injection is not scheduled to begin within three months of the scheme approval, the AER may decide to grant GPP after written notification to the AER that injection has commenced. Wells outside of the approval area will normally remain on MRL.

If granted with the condition that injection will begin within three months, GPP will be effective concurrent with the ER scheme approval. Wells must not produce above their MRL before GPP is granted. With the granting of GPP before confirmation that injection has commenced, the AER expects operators to prudently produce their wells pending the successful implementation of ER.

For oil pools on GPP administration, upon approval of a new ER scheme or ER scheme amendment, GPP will normally be retained for wells within the approval area. For wells outside the ER approval area, the AER may require the well licensees to address ER feasibility and the appropriateness of continued GPP status.

B) Wellbore Integrity and Completion Requirements

Wellbore integrity requirements and application processes are detailed in AER *Directive 051*.

The *Directive 051* application, in most cases, may be submitted before, at the same time as, or after the submission of the ER scheme application. Injection may not, however, begin without the receipt of written confirmation that the ER scheme application has been approved and the *Directive 051* requirements have been met.

C) Reserves

The AER sets ER reserves outside of the ER scheme application review process, but a nominal amount of reserves information is useful in providing a better understanding of the intent of this application. Processing of ER scheme applications will not be delayed to conduct a detailed review of reserves, but ER reserves will be set as soon as possible after approval of an ER scheme. Approval holders may be required to provide additional, up-to-date reserves information outside the application review process.

Reserves changes are not communicated directly to companies, but AER reserves estimates are available upon request through the Customer Contact Centre. Any well rate administration changes that result from reserve changes are reflected in the monthly MRL order.

D) Use of Nonsaline Water

The AER supports the water management objectives of Alberta's *Water for Life: Alberta's Strategy for Sustainability* and the reduction plans outlined in the *Advisory Committee on Water Use Practice and Policy Final Report*. Accordingly, applicants proposing to use nonsaline water in an ER scheme must obtain prior approval from Alberta Environment and Protected Areas (AEPA) under the *Water Act* for the diversion of the nonsaline water. This approval must be obtained before submitting an application for an ER scheme to the AER. AEPA requires applicants for water diversion to fully investigate alternatives and submit evidence that there are no practical alternative saline water sources. For information on a water diversion application, contact the regional offices of AEPA.

2.1.2 AER Requirements and Expectations for ER Schemes

The AER's objective in regulating ER schemes is to ensure that hydrocarbon recovery is optimized. In meeting this objective, the AER must also ensure that scheme operations are conducted in a manner that is safe, is in the best interest of the public, protects the environment, and is fair to other well licensees.

2.1.2.1 Scheme Requirements

Scheme requirements are those rules that must be met and against which the AER will take enforcement action in cases of noncompliance. In addition to all other requirements of the *Oil and Gas Conservation Act* and *Rules*, the following are some specific requirements for all ER schemes:

- The approval holder is responsible for the successful operation of an ER scheme.
- The approval holder must comply with all conditions of ER scheme approvals.
- The approval holder must be the current operator of the scheme.
- Injection must not begin in a well until after written confirmation that the ER scheme application has been approved and the *Directive 051* requirements have been met.
- Gas-cap gas production requires AER approval for concurrent production.
- The type of ER scheme (e.g., waterflood, miscible flood, gas cycling) must be selected and operated to maximize hydrocarbon recovery.
- At the application stage, CO_2 EOR storage must demonstrate residual hydrocarbon recovery and permanent net geological storage of CO_2 in the approved scheme approval area.

- The proposed approval area must reflect the area that will be effectively swept by the injection wells and must conform to the AER-approved spacing.
- The approval will only list existing injection wells and wells that have been licensed or are in the process of being licensed under *Directive 056*.
- Injection pressures must remain below the approved MWHIP at all times.
- The approval holder must comply with the initial and subsequent *Directive 051* requirements.
- Gas must be conserved in accordance with *Directive 060: Upstream Petroleum Industry Flaring Guide*.
- Injection operations that contain fluid with any H_2S must meet the requirements of *Directive 071: Emergency Preparedness and Response Requirements for the Petroleum Industry*.

2.1.2.2 Scheme Expectations

Although optimal operating practices may vary for each reservoir, there are fundamental principles and practices that the AER expects to be followed, in addition to the above-noted requirements, for all ER schemes. AER expectations on how ER schemes should be assessed, designed, implemented, and operated are described below.

A) Assessment Stage

- For all pools, including those that are on GPP, the feasibility of ER should be reviewed on an ongoing basis.
- For retrograde gas condensate pools, the feasibility of gas cycling should be evaluated before reaching the dew point pressure in order to maximize hydrocarbon recovery.
- Well licensees should collect the appropriate reservoir data necessary to accurately assess ER potential.
- ER should normally be evaluated and, if feasible, implemented in oil pools prior to the production of the gas cap and before the pool pressure declines below the reservoir fluid bubble point pressure.
- Pool delineation should be well understood prior to designing and implementing an ER scheme.
- The applicant should have a good understanding of the reservoir and fluid properties prior to designing the ER scheme.
- For EOR CO_2 storage schemes, storage capacity must be determined. Storage capacity is defined as the amount of pore space in the applied for pool area including the miscible portion that is available for CO_2 storage.

B) Design Stage

- Produced water should be reinjected in water injection schemes.
- Production wells that are second or third line offset from injection wells should be included in the proposed scheme only when it is anticipated that the proposed injection wells will be able to provide adequate sweep and pressure support.

C) Implementation Stage

- Injection operations should be initiated at the optimal time. Injection should begin before the reservoir pressure drops below the bubble point pressure in oil pools or the dew point pressure in the case of retrograde gas condensate pools.
- Injection operations in all approved injection wells should begin as soon as possible. The AER will specify a deadline for the commencement of injection of three months from the date of the approval or amendment.

D) Operations

- If there are multiple well licensees within the approval area, the approval holder is expected to coordinate the scheme operations to ensure that maximum hydrocarbon recovery is attained.
- All well licensees in the approval area are expected to adhere to the approval conditions.
- Well licensees should collect the appropriate reservoir data necessary to accurately assess an ER scheme and optimize scheme performance.
- Alternatives to nonsaline water injection should be assessed on an ongoing basis.
- The entire approval area should have a uniform voidage replacement and pressure distribution.
- Where feasible and appropriate, the ER scheme should be operated at a reservoir pressure close to the bubble point pressure or dew point pressure.
- To provide operating flexibility, an ER approval does not need to be amended to remove wells that have ceased injection.
- Well licensees are expected to prudently produce their wells pending the successful implementation of ER.
- ER schemes should be monitored and adjustments or changes made to ensure optimum recovery.
- In the case of a CO_2 EOR storage scheme, monitoring is required as outlined in section 2.1.4.

2.1.3 Requirements for ER Scheme Applications

2.1.3.1 Requirements That Must Be Met Before an ER Application Is Submitted

An ER application may be submitted to the AER once the following requirements have been met:

- The primary applicant has obtained the right to represent all well licensees within the proposed approval area.
- The proposed injection wells have been drilled, except where an injection well is being applied for using the two-step process.
- There are no differences between the applicant's and the AER's interpretation of pool delineation that are pertinent to the ER scheme, as described in section 2.1.1.2.
- For a scheme amendment, the primary applicant is the approval holder.

2.1.3.2 Minimum Notification Requirements for ER Scheme Applications

Minimum notification requirements are outlined in the section "Resources Applications Notification Guidelines" in the preamble of this directive as well as in tables 1, 2, and 3. Notification must include scheme details such as approval area, type of ER scheme, and injection well locations to all well licensees before submitting the application to the AER. Failure to complete notification as required may result in an application being closed without being processed.

Special circumstances, such as pressure communication between pools through a common aquifer, may expand the notification requirements.

The AER expects well licensees to act in the best interest of all parties with an interest in a well, including lessees and lessors, particularly in cases of mixed ownership within the proposed approval area.

Applicants must retain the list of well licensees notified about the proposed scheme/amendment, the notification document, and any responses or comments received. This information is not required to be submitted as part of the ER application unless there are unresolved licensee concerns. In this case, a Licensee Concerns attachment must be included.

2.1.3.3 Forms and Attachments Required for ER Scheme Applications

A) Summary of Required Application Documents

All ER scheme applications must include

- Resources Applications – Schedule 1
- ER scheme application form (appendix F)
- Attachments
  - Application
  - Approval area map
  - Pressure-volume-temperature (PVT) data (required for new enhanced oil recovery schemes and recommended for amendments)
  - Reserves data (required for new enhanced oil recovery schemes and recommended for amendments)
  - Injectivity test data (if not available, MWHIP prescribed by table 1 of appendix O)
  - Licensee concerns (if there are any unresolved concerns)
  - Isopach map (for new ER schemes and significant area amendments)
  - Well logs (for new ER schemes and significant area amendments)
  - Pressure data and interpretation (for new ER schemes and significant area amendments)
  - Structure map (for new gas cycling schemes)
  - Miscellaneous (additional information to support the request)

Further explanation on the ER scheme application form and attachments is provided in the following sections (B) and (C).

B) Explanatory Notes for ER Scheme Application Form Questions

The ER scheme application form is in appendix F. The numbering below corresponds to the questions on the form.

Application Type

1) Type of ER scheme being proposed or amended:

Only one type of ER scheme may be selected. Although schemes may have multiple types of injection fluid, there generally is a predominant recovery mechanism or scheme type. For example, a scheme with water-alternating-gas (WAG) injection is a miscible scheme even though solvent, water, and gas would be injected during the scheme's life.

If you choose Other, you must include a description of the ER process and supporting technical documents/papers discussing the method in the application.

2) *Is this application for a new ER scheme or for an amendment to an existing ER scheme approval?*

If an AER approval for ER does not exist for the subject scheme, select New.

If an AER approval for ER exists for the subject scheme, select Amendment.

3) *What is the existing AER approval number proposed for amendment?*

If the application is for an amendment to an existing ER scheme approval, enter the current approval number without alpha characters.

4) *Type of Amendment:*

If the application is for an amendment to an existing ER scheme approval, the type of amendment must be selected. Multiple amendment types may be selected, with the exception of "Scheme termination," which must be a singular ER scheme amendment type.

Add injection well locations: Select this box if you are requesting approval to add one or more injection well locations to the approval.

Amend approval area: Select this box if you are requesting a change to the current approval area (shown in the appendix to the approval). The proposed approval area should reflect the area that will be effectively swept by the injection wells and should conform to the AER-approved spacing.

Amend approval conditions: Select this box if you are requesting a change to a condition of the approval. For example, this could include changes to the minimum operating pressure or voidage replacement requirements, but not a change to the holder of the approval.

Scheme termination: Select this box if you are requesting approval to rescind the ER approval.

Ownership and Notification Information

5) *The primary applicant must*

   a) *be the proposed approval holder for a new scheme or the current approval holder for an existing scheme, and*

   b) *represent all well licensees in the proposed approval area.*

   Have these requirements been met?

YES means that both of these requirements have been met and the primary applicant accepts responsibility for compliance with all conditions of the approval.

NO means that one or both of these requirements have not been met, and as a consequence the application may not be submitted. Any request to change the approval holder must be made in accordance with unit 5 of this directive.

6) *An ER scheme application cannot be submitted until notification of all well licensees has been completed in accordance with* Directive 065.

Has notification been completed in accordance with *Directive 065*?

YES means that the notification requirements specified in section 2.1.3.2 have been met.

NO means that these requirements have not been met. An ER scheme application may not be submitted until these requirements have been met.

7) *Are there outstanding concerns from well licensees? If yes, the licensee concerns attachment must be submitted as part of the application, in accordance with* Directive 065.

YES means that there are unresolved concerns or objections from one or more of the well licensees that were notified of the application. The information required in a licensee concerns attachment is identified in section 2.1.3.3(C) of this directive.

NO means that there are no known unresolved well licensee concerns from any of the well licensees that were notified of the application.

Proposed Injection Well Locations and Injection Intervals

Complete this section for new ER schemes and amendment types when requesting to add injection well locations.

8) *An ER scheme application cannot be submitted unless the source of the proposed injection fluid has been secured.*

Has the source of the proposed injection fluid been secured?

YES means that the supply of injection fluid is secured and will be available for use by the proposed injection date.

If nonsaline water is to be used for injection, you must have a valid water diversion permit from the AER. The water diversion permit number must be provided in the application attachment.

NO means that the injection fluid source has not been secured. The AER is not prepared to accept an ER application when the injection fluid has not been secured because of the potential for delays in the commencement of injection.

9) *Provide the following for the proposed injection well locations:*

Use a well location completed in the subject pool if the optional two-step pre-drill application process is to be adopted.

Well Licence Number: The well licence number issued by the AER for the proposed injection well.

Unique Well Identifier (UWI): The UWI (LE/LSD-SEC-TWP-RGEWMER/ES) associated with the well licence number. This parameter is populated on the basis of the well licence number provided. Please note that only wells with an active status can be used here.

Injection Interval: The top and base depth of the injection interval.

Porosity Interval: The porosity top and porosity base depth of the reservoir proposed for injection.

Fluid Interface: The current gas/oil and oil/water depths (if applicable) in the reservoir proposed for injection. These depths may be measured or estimated.

10) *What type of injection fluid, as identified by* Directive 051*, will be used?*

Multiple injection fluids may be selected. Further descriptions of the injection classes are in *Directive 051*.

10a) *The applicants or approval holders must meet the requirements in* Directive 071: Emergency Preparedness and Response.

11) *Will injection commence in all proposed injection wells within twelve months of receipt of approval?*

If no, a discussion addressing the anticipated commencement of injection and the reason for the delay must be included in the application attachment, in accordance with Directive 065.

YES means that injection will begin within twelve months of the date of approval. This commencement of injection date will be a condition of the approval.

NO means that injection will not begin within twelve months of receipt of approval. Provide reasons for the delay in the commencement of the injection date beyond the standard three-month period. If injection will not begin within three months, the AER will generally not grant GPP at the time of the ER approval due to conservation concerns. The AER may decide to grant GPP after written notification to the AER that injection has begun.

Proposed Approval Area

Complete this section for new ER schemes and amendment types when requesting an amendment to the approval area.

12) *Is the entire proposed approval area within the AER's pool order boundary for the subject pool?*

YES means that the entire proposed approval area is within the AER's current pool order boundary for the subject pool.

NO means that the proposed approval area extends beyond the AER's current pool order boundary for the subject pool. The AER cannot approve ER approval areas larger than the pool order boundary. Differences in pool delineation should be addressed before submitting the ER application. Note that the approval area will not include injectors without hydrocarbon pay, but such injectors may be listed in the approval.

The AER's pool order boundaries are under the AER Order System on the Systems & Tools portal of the AER website, www.aer.ca.

13) *Does your interpretation of pool extent correspond to the AER's pool order boundary for the subject pool?*

YES means that your interpretation of pool extent coincides with the area identified by the AER's current pool order boundary for the subject pool.

NO means that your interpretation of pool extent does not coincide with the area identified by the AER's current pool order boundary for the subject pool.

The AER's pool order boundaries reflect quarter section for wells with oil pay and one section for wells with gas pay.

14) *Is the difference in pool delineation interpretation pertinent to the proposed ER scheme, in accordance with* Directive 065?

Provide a discussion of the difference in pool delineation and the pertinence to the proposed ER scheme in the application attachment, in accordance with Directive 065.

A difference in pool delineation (e.g., the proposed approval area extends beyond the AER's pool order boundary for the subject pool or your interpretation of pool extent does not coincide with the AER's pool order boundary for the subject pool) is considered pertinent if it affects any of the following aspects of the proposed ER scheme: approval area, approval conditions, notification, or approved injection wells.

Pool delineation is very important to the AER's review of any ER scheme. The assessment of the effectiveness of the proposed scheme relative to the optimal depletion strategy for the entire pool requires that overall pool delineation be known. Also, accurate pool delineation is necessary to allow for the identification of possible equity concerns involved with the proposed ER scheme.

YES means that your pool interpretation differs from that of the AER in a manner that could affect the ER approval. Significant differences in pool delineation must be dealt with before making an ER scheme application. However, an exception may be where the proposed approval area is larger than the pool order boundary due to wells that are yet to be evaluated by the AER.

NO means that your pool interpretation differs from that of the AER in a manner that does not affect the ER approval. For example, the recognized differences are significantly outside of the proposed approval area.

Scheme Details

15) *Is the scheme area currently administered under good production practice?*

YES means that all of the wells within the proposed approval area have been granted GPP.

NO means that some or all of the wells within the proposed approval area are subject to a prescribed maximum rate limitation (MRL) or that the proposed scheme is in a gas pool.

A copy of the most recent MRL order can be found on the AER's website.

16) *Will produced gas from the ER scheme area be conserved in accordance with* Directive 060 *requirements?*

The AER expects that gas conservation is in accordance with *Directive 060*.

17) *What is the proposed voidage replacement ratio (VRR), on a monthly basis, for the scheme?*

The AER normally specifies a cumulative VRR of 1.0 from production initiation as the upper bound, and a monthly VRR greater than a level chosen by the applicant as the lower bound. A technical justification is required if the elected cumulative VRR is greater than 1.0 or the monthly VRR target is lower than 0.2.

The VRR should reflect the injection into and production from the total scheme area. The AER will normally specify a VRR as a condition of the approval.

18) *Is or will any gas-cap gas be produced from the subject pool during the operation of the ER scheme?*

If yes, include a discussion on the potential for fluid migration into the gas cap in the application attachment, in accordance with Directive 065.

YES means that gas-cap gas is or will be produced from the pool, either within or outside of the scheme area, during the period that the ER scheme is operational.

If any gas-cap gas is or will be produced from the subject pool during the operations of the ER scheme, provide a discussion on the potential for fluid migration from the scheme into the gas cap and pressure depletion in the scheme due to gas-cap gas production. If potential for fluid migration or pressure depletion is identified, the discussion should include the impact on ultimate hydrocarbon recovery.

NO means either that there is no associated gas cap in the pool or that the associated gas cap will not be produced during the period that the ER scheme is operational.

19) *Is gas-cap gas currently being produced from the scheme area?*

YES means that an associated gas cap is present in the pool and this gas is currently being produced from the scheme.

NO means that an associated gas cap is present in the pool but this gas is not currently being produced from the scheme.

19a) *Has the appropriate concurrent production (CCP) approval been issued?*

If question 19 is answered yes, gas-cap gas is currently being produced from the scheme area and this question must be answered.

YES means that the appropriate form of concurrent production that encompasses the current gas-cap gas production has been approved by the AER. The CCP approval details are listed in the AER's MRL order.

NO means that the current gas-cap gas production has not been approved by the AER.

19b) An application for CCP is required. Has an application for CCP been registered?

If question 19a is answered no, the current gas-cap gas production has not been approved by the AER and this question must be answered.

YES means that an application for CCP has been registered with the AER.

NO means that an application for CCP has not yet been registered with the AER. Unauthorized CCP is not permitted; an application for CCP is required pursuant to section 39(1)(f) of the *OGCA* and section 2.4 of this directive.

19c) If yes, provide the CCP application number.

If question 19b is answered yes, an application for CPP has been registered with the AER and this question must be answered.

If an application for CCP has been registered, enter the AER application number. Information details on applications registered with the AER are on the AER's website.

C) Explanatory Notes for ER Scheme Application Attachments

Application Attachment

1) Provide an attachment that describes the proposed scheme, including
   - the proposed injection pattern;
   - the expected sweep efficiencies (e.g., vertical, areal);
   - the displacement type (e.g., bottom water drive, horizontal);
   - the measures taken to prevent channeling and to maximize the swept reservoir volume;
   - the proposed date of commencement of injection;
   - the approximate date when the proposed VRR will be achieved; and
   - the type, composition, and source of the injection fluid, including chase gas for miscible floods. For changing injection fluid compositions, provide the anticipated range of compositions; for nonsaline water injection, provide the water diversion permit number.
2) If all of the proposed injection wells will not begin injection within three months of the approval date, include a discussion addressing the anticipated commencement of injection for each injection well and the reason for the delay. Injection dates up to six months from the date of approval may be considered by the AER.

3) If your interpretation of pool delineation is different than the AER's interpretation, as reflected by the current pool order boundary, include a discussion of the difference in pool delineation and why the difference is not pertinent to the proposed ER scheme. In cases where wells in the proposed scheme area have not yet been evaluated by the AER, the wells requiring review should be identified.
4) If the proposed VRR is greater than 1.0 or is lower than 0.2 on a monthly basis, provide technical justification for a VRR outside of this range, including the reasons for the over- or under-injection and its impact on scheme recovery. For example, if partial pressure maintenance is provided by an associated aquifer, include detailed analysis to show that the proposed VRR in combination with the aquifer will maintain reservoir pressure.
5) If any gas-cap gas is or will be produced from the subject pool during the operations of the ER scheme, provide a discussion on the potential for fluid migration from the scheme into the gas-cap and pressure depletion in the scheme due to gas-cap gas production. If potential for fluid migration or pressure depletion is identified, the discussion should include the impact on ultimate hydrocarbon recovery.
6) If any gas-cap gas is currently being produced from the proposed scheme area and the appropriate concurrent production approval does not exist, provide a discussion of your plans to submit a concurrent production application.

Approval Area Map Attachment

Maps showing

1) the AER's current pool order boundary for the subject pool (see the AER Order System on the Systems & Tools portal of the AER website);
2) the location and current status (indicated by well symbols) of each well
    - within the proposed approval area and
    - within the notification area specified in section 2.1.3.2,

    with wells completed in the pool highlighted;
3) the outline of other existing ER recovery scheme approval areas within the pool that offset the subject scheme; and
4) for a **new ER scheme**, include the applied-for approval area, and for an **ER amendment application**, include the current approval area and any proposed areas of amendment and the zero edge of the pool.

The proposed approval area must reflect the area anticipated to be swept by the scheme injectors and should conform to the AER-approved drilling spacing units.

For clarity, the information may be provided on separate maps.

For very large pools, the map should focus on the region in and surrounding the scheme area.

For a new scheme, the net oil/gas pay isopach maps must be provided as a separate attachment. For scheme amendments, the pool zero edge in the region of the proposed scheme area must be provided.

PVT Data Attachment

PVT properties must be provided, including the source of the data.

Reserves Data Attachment

Estimates of the oil and gas reserves must be provided, including estimation technique.

A fundamental service that the AER provides to all stakeholders is maintaining reserve estimates for all pools in Alberta.

A nominal level of reserves information is required in ER scheme applications, and more detail may be required for applications involving more complex ER processes. As well, additional information may be requested during the application review, after approval, or during a future audit.

Maximum Wellhead Injection Pressure Attachment

All injection wells will be subject to an MWHIP. Best practices for the determination of the MWHIP are based on the formation fracture pressure with a safety factor applied. The formation fracture pressure may be determined from a step-rate injectivity, in-situ stress tests, or reliable and analogous offset data. In the absence of such information, the MWHIP prescribed in appendix O, table 1, will be assigned to the injector.

The requirements for the determination of MWHIP include

- a statement on the basis of the proposed MWHIP, if requesting MWHIP other than as prescribed by appendix O, table 1;
- a technical justification for all analogous source proposals;
- a technical justification for the proposed MWHIP. This will include the complete test data and all analysis;
- a discussion about the proposed safety factor for use in the determination of the MWHIP to ensure fluid containment; and

- the wellbore configuration expected to be used during injection operations. Any deviations from this configuration that could result in a higher bottomhole injection pressure will require a *Directive 065* application for a revised MWHIP.

Licensees are responsible for providing the historical wellhead injection pressure data to the AER for an audit.

An application for the amendment of the MWHIP, assigned with appendix O (table 1), should be submitted as an ER scheme (amend) application through DDS, addressing the above requirements for MWHIP.

Licensee Concerns Attachment

If there are unresolved concerns from a well licensee, provide an attachment that includes the following information:

1) contact information for the well licensee that has unresolved concerns;
2) a copy of the notification letter provided to the well licensees;
3) a list of any other documents distributed;
4) copies of any statements of concerns received, or if not available, a summary of issues;
5) a chronology of any discussions conducted with the well licensees;
6) a discussion of how the applicant would like the AER to proceed with the application; and
7) a statement on the steps taken to mitigate the unresolved concerns and the applicant's response to the concerns.

Isopach Map Attachment (for new ER schemes and significant area amendments)

Provide an isopach map of net oil and/or gas pay showing

1) the location of the initial fluid interfaces (gas-oil, gas-water, oil-water), and
2) the location and current status (indicated by well symbols) of each well within and offsetting the proposed approval area.

The AER requires the geological extent and hydrocarbon pay thickness of a pool, any fluid interfaces, and well control with statuses to assess how the proposed scheme relates to optimum pool depletion, other existing schemes, and potential pool delineation and equity issues.

For very large pools, the map should focus on the region in and surrounding the scheme area.

Well Log Attachment (for new ER schemes and significant area amendments)

Provide an interpreted and annotated log cross-section or representative well logs showing

1) stratigraphic interpretation of the zones of interest,
2) interpretation of fluid interfaces (original and current, if applicable),
3) completion and treatments to the wellbores, with dates,
4) cumulative production,
5) finished drilling date and kelly bushing elevation, and
6) the scale of the log readings.

This cross-section may be presented in a number of ways—as one representative well log, several well logs, or a detailed cross-section of the entire pool—depending on the complexity and heterogeneity of the pool. The information on this cross-section assists in establishing the vertical continuity within the pool and the overall quality of the pool.

Pressure Data and Interpretation Attachment (for new ER schemes and significant area amendments)

Provide reservoir pressure data, including

1) measured or estimated reservoir pressures for the scheme area,
2) the source of the data, and
3) a discussion of how the pressure data relates to and supports the scheme operations.

The applicant must include all pressure data available for scheme wells. The data may be presented in various formats, such as a pressure-time plot, an isochronal map, or a table illustrating the pressures for the scheme wells. Pressure data should be corrected to the AER established pool datum.

All pressure data must be in metric units.

Reservoir pressure data are a key component in ensuring the success and optimal operation of ER schemes. Taking timely and representative reservoir pressure measurements ensures that the necessary information is available to help monitor and optimize scheme performance. All new ER schemes will be added to the annual pressure survey schedule unless otherwise stated.

Structure Map Attachment (requirement for new gas cycling schemes)

Provide a structure map of the subject pool clearly identifying interpreted fluid interfaces (current and original, if applicable), stratigraphic horizon, and contoured surface (porosity top or formation top).

If the proposed ER scheme is for a gas cycling scheme or an ER scheme where vertical displacement is important for evaluating the scheme design, a structure contour map must be provided.

D) Additional Requirements for ER Scheme Amendment Applications

The requirements listed in this section are supplemental to the mandatory requirements and vary according to the type of amendment.

Add Injection Well Locations

Provide a technical explanation of why the additional injection locations are required and how they are consistent with the optimal depletion strategy, which is to ensure that hydrocarbon recovery from the scheme area is maximized.

Amend Approval Area

Provide a written description of the proposed changes to the approval area. For a significant expansion to the area of an existing scheme, the AER requires the isopach map, well logs, and pressure data and interpretation attachments.

Amend Approval Conditions

Provide the specific details of and technical justification for the proposed changes to the approval conditions.

Scheme Termination

An application to rescind an ER approval is required to terminate an ER scheme. Generally, termination of the scheme involves ceasing all injection.

An application to rescind an ER approval must include

1) a discussion of the reasons for termination of the scheme, including how the pressure and production performance justifies the request for termination;
2) a discussion of the future depletion strategy for the approval area and the remaining recoverable reserves; and

3) a discussion of the success of the ER scheme, including the details of the actual incremental volumes by recovery mechanism (e.g., primary, waterflood, gas cycling, miscible flood).

All scheme amendment applications must include a statement on the state of compliance with the existing approval conditions.

E) Additional Requirements for Miscible Flood Scheme Applications

The requirements listed in this section are supplemental to the mandatory requirements and are specific to new miscible flood schemes. Amendments to existing miscible flood schemes should only address the requirements necessary to justify the request.

An application for a new miscible flood scheme must include

1) proof of miscibility with the reservoir oil; proof usually requires slim tube or rising-bubble tests over a range of injection fluid compositions and/or pressures to establish the point or boundary of miscibility;
2) the proposed miscibility conditions, as appropriate, established from the following:
   a) the minimum miscibility pressure (MMP) at the proposed composition of the injection fluid:

      The MMP is the lowest pressure for which the injection fluid can develop miscibility through a multicontact process with the given reservoir oil at reservoir temperature. To maximize oil recovery, the AER may specify a minimum operating pressure (MOP) in the approval. The specified MOP will usually be nominally higher than the MMP to incorporate a safety factor for miscibility;

   b) a correlation of injection fluid composition versus operating pressure;
   c) the minimum pseudocritical temperature of the injection fluid and MOP;
   d) the minimum C2+ content of the injected fluid and MOP; and
   e) other conditions to ensure miscibility; and
3) the methodologies proposed to be used to determine when injection fluid breakthrough occurs and to calculate the volumes of injection fluid breakthrough. Fluid sampling and analysis for miscible flood schemes, where required, have the following minimum requirements:
   a) gas sampling and analysis on a quarterly basis for all produced wells where no other method is available for the estimation of the breakthrough volumes of each fluid at the producers; and
   b) sampling and analysis of the injected solvent and chase gas on a quarterly basis.

F) Additional Requirements for Gas Cycling Scheme Applications

If an operator considers gas cycling appropriate, submit an application for an ER scheme. Amendments to an existing gas cycling scheme should only address the requirements necessary to justify the request. In addition to the requirements for an application for a new ER scheme, an application for a new gas cycling scheme must include

1) the proposed rate of cycling and the cycling period before blowdown commences with supporting technical and economic data;
2) the following historical and forecast annual production under various depletion strategies (including primary depletion, partial gas cycling, and full gas cycling):
   a) raw gas,
   b) sales gas,
   c) individual liquid coproducts, and
   d) sulphur;

   this performance information for gas cycling schemes should provide the basis for the economic evaluation used in determining the optimum depletion strategy;
3) the forecast annual gas injection showing the portion of make-up gas versus reinjected gas;
4) the composition of the current gas-cap gas, and the average composition of the injected gas on an annual basis;
5) the estimated liquid and sales gas recovery by the various depletion strategies compared to primary depletion; and
6) economic evaluation used to determine the optimum depletion strategy.

The quantification of natural gas liquids carried in the gas cap is of primary importance to the feasibility of the scheme.

2.1.4 Additional Requirements for Carbon Dioxide (CO_2) EOR Storage Schemes

Carbon dioxide (CO_2) EOR storage schemes are often referred to as carbon capture, utilization, and storage (CCUS) projects. CO_2 EOR storage schemes should optimize flood design and well placement for extracting additional residual oil and promote long-term storage and trapping (net geological sequestration) of CO_2.

In addition to the detailed requirements in the following table, a CO_2 EOR storage scheme application must

1) define the storage capacity estimates and injectivity,

2) develop models and execute simulations to predict the extent of the CO_2 fluid plume (the free-phase injected CO_2 in the pool),

3) predict the behaviour of the hydrocarbon-CO_2 phase,

4) confirm that the proposed scheme will perform effectively and safely,

5) establish a site-specific risk assessment that will allow for thorough risk management throughout the life of scheme approval and outline risk factors, threats, preventive controls, top events, hazards, mitigative controls, and consequences,

6) establish baseline conditions to design and implement a monitoring program, and

7) assess the risks associated with storage and remediation strategies in case of loss of containment.

The risk assessment includes the identification of safety-critical preventive and mitigative controls (such as safety-critical equipment and safety critical human actions, as defined in *CSA Z767 Process Safety Management*) and monitoring their effectiveness throughout the life of a scheme. The level of detail in a risk assessment should be proportionate to the risk and appropriate to the nature of the hazard. See the latest edition of the following standards for guidance on risk assessment: *CSA Z767 Process Safety Management* and *CSA IEC 31010 Risk management – Risk assessment techniques*.

The extent of the CO_2 fluid plume is a useful concept for the AER to evaluate containment and identify high-risk offset wells. Models and simulations should be used (as applicable on a site-specific basis) to evaluate and predict the behaviour of the CO_2 EOR storage scheme area and to inform the risk assessment. Include a discussion of the maximum and final expected extent of the CO_2 fluid plume surrounding the proposed wells over the life of the scheme, including any pressure gradients that exist because of past or current production or injection operations.

The scheme approval areas and the proposed injection wells must be within the AER pool boundary. Changes to an approval area can be requested at any time by submitting a CO_2 EOR storage amendment application. The containment assurance requirements outlined in the following table are a component of a monitoring, measurement, and verification (MMV) plan. An operator of a CO_2 EOR storage scheme should maintain a MMV plan that is appropriate for a CO_2 EOR storage scheme for the life of the scheme approval and follow the applicable principles and objectives outlined in appendix P.

The MMV plan should be risk based and site specific and address health, safety, and environmental risks, evaluate storage performance, and provide evidence for long-term safety and security of the CO_2 within the approval area.

2.1.5 Application Requirements for a CO_2 EOR Storage Scheme

Equity

Requirements	Comments
1) Evidence that you have been issued the appropriate rights by Alberta Energy and Minerals to inject CO_2 into the proposed zone.	

Conservation

Requirements	Comments
2) If an immiscible flood is proposed, evidence of improved sweep efficiency for the extraction of residual oil and promote the storage of CO_2.	
3) A description of the planned CO_2 flood as a) continuous CO_2 injection, b) different modes of WAG, c) using chase gas or otherwise, and d) the composition of each injection.	

4) The screening criterion for selecting oil reservoirs for CO_2 EOR storage and estimates of incremental oil or gas recovery with corresponding theoretical CO_2 storage capacity.

Theoretical assessments of CO_2 storage capacity in oil and gas reservoirs should be based on the reserves database and reported in tonnes of CO_2. This method assesses the total amount of produced and injected fluids to estimate the volume of CO_2 that could be stored in the pool above the hydrocarbon-water contact.

Theoretical assessments of CO_2 storage capacity should use volumetric means of calculating the CO_2 storage capacity in oil and gas reservoirs based on oil in place for oil reservoirs, gas in place for gas reservoirs, and the geometry (areal extent and thickness) of the reservoir.

The pore volume invaded by water from underlying aquifers could be estimated with monitoring of the gas-oil-water interface and knowledge of reservoir characteristics.

Containment Assurance

Requirements

5) A demonstration of geological containment of the CO_2 EOR storage reservoir and the following information for the applied-for scheme area:

   a) a geological discussion on the upper and lower confining intervals (lithology, continuity, thickness, integrity, and extent)

   b) isopach maps of the upper and lower containment intervals

   c) an interpretated and annotated cross-section demonstrating the continuity and extent of the confining intervals

Comments

Maps and cross-sections should include an expanded area if any impacts to containment are presumed or interpreted beyond the applied-for scheme area.

d) maps showing known faulting that could compromise containment with a supporting discussion

e) any interpreted seismic data that provides further information regarding containment assurance

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6) If a subsurface risk to the containment of the CO_2 EOR storage reservoir is known, interpreted, or presumed by the applicant, then the following is required:

   a) Identification of above-zone monitoring intervals and proposed monitoring well locations. The intervals and proposed well locations may be subject to the following requirements:

      i) pressure monitoring

      ii) annual carbon isotope sampling of producing fluids

      iii) bi-annual gas sampling for chemical compositional analysis

   b) The AER may require changes to proposed monitoring well locations, or additional monitoring wells, if, in its opinion, circumstances so warrant.

Subsurface containment of CO_2 is of utmost importance. It is necessary for the AER to determine that there will be no migration to other zones or groundwater.

The focus of containment monitoring should be the earliest detection of CO_2 migration out of the CO_2 EOR storage reservoir.

Above-zone containment monitoring wells should be appropriately distributed throughout the scheme area.

Above-zone containment interval samples must be collected from current producing wellbores or wellbores capable of production.

7) A groundwater monitoring program is required that

   a) ensures protection of nonsaline groundwater

   b) establishes baseline data for nonsaline aquifers

The scheme operator must submit a site-specific groundwater monitoring program above the base of groundwater protection (BGWP).

c) demonstrates that the scheme will not degrade existing water quality d) summarizes planned measures to mitigate effects and any anticipated residual effects e) monitors industry and domestic monitoring wells, where appropriate	
8) If a subsurface risk to the geological containment of the CO_2 EOR storage reservoir is known, interpreted, or presumed by the applicant, identify all above-zone, at-risk aquifers, including the following within the applied for scheme area: a) an isopach and structure map for each aquifer b) potentiometric surface maps in metres of freshwater equivalent head above sea level c) plots of representative pressure head measurements versus depth and representative pressure head measurements versus elevation with comparisons to hydrostatic pressure and an assessment of hydraulic communication between aquifers	
9) Results of modelling and simulations undertaken (as applicable on a site-specific basis).	The scheme operator should collect sufficient data needed to verify and update models and simulations annually.

10) A surface casing vent flow (SCVF) / gas migration (GM) plan that satisfies *Directive 087: Well Integrity Management* requirements for wellbore locations within the CO_2 fluid plume.

Directive 087 section 3.1.1(h) defines a serious SCVF as one that constitutes a fire, public safety, or environmental hazard. Until the source depth or formation origin is determined as outlined in *Directive 087* section 3.4.1, there is a risk that the surface SCVF could be related to ongoing downhole operations.

Safety

Requirements

11) A list of the formation fracture pressures and fracture propagation pressures for the storage formation with a description of how they were determined.

12) For the bounding formations, provide

   a) continuity and thickness of base and caprock,

   b) lithology,

   c) evidence of fracturing,

   d) caprock threshold pressure, and

   e) a discussion of the integrity of the base and caprock and its containment features.

Comments

Long-term reservoir containment of CO_2 may be of a concern if the average reservoir pressure exceeds the initial pool pressure.

It is necessary to determine if the formation may be fractured and the extent to which the fractures may spread. Fracturing of the reservoir and the caprock due to dynamic changes in the thermal gradient should also be considered over the life of the scheme, including monitoring of the injectivity.

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13) For CO_2 EOR storage scheme applications requesting an MWHIP, a recent injectivity test that is representative of the reservoir conditions prior to the commencement of the CO_2 injection.

   a) The safety factor must be applied at the bottomhole formation fracture pressure

Injectivity tests conducted at the early stage of pool production may not be representative of the fracture pressures of a pressure depleted pool being considered for CO_2 EOR storage.

If the injectivity test was conducted with only wellhead measurements, the calculation of the bottomhole pressures must account for the frictional losses.

b) Analogous offset data must be supported with a brief geological assessment indicating its suitability.

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14) A statement indicating that notification of the scheme for emergency response plan (ERP) purposes has been made. Details of any outstanding concerns from the notified parties must be included.

Where facilities may pose a risk to the public, ERP requirements must be met prior to commencement of operations. Generally, an ERP is required if a risk assessment indicates that there are members of the public within a defined hazard area. Ensure that the requirements in *Directive 071: Emergency Preparedness and Response* have been met. Questions may be directed to the Emergency Management help line at 403-297-2625 or EPAHelpline@aer.ca.

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15) A wellbore risk assessment that

a) reviews new and existing wellbores within 1.6 km beyond the CO_2 fluid plume to assess for and manage risks over the life of the CO_2-EOR storage approval. The review must consider expected development plans and

i) the locations of proposed injection and production wells,

The CO_2 fluid plume is the free-phase CO_2 injected in the EOR scheme area.

The risk assessment should address communication, reservoir containment, protection of other hydrocarbon zones, protection of groundwater intervals, and surface impacts.

Risk management should be iterative, systematic, technically defensible, aligned with containment assurance plans, and support post-EOR termination plans.

   ii) opportunities to convert existing wells for observation and monitoring, and

   iii) justify any wells that will not be upgraded to the Level A abandonment standards in *Directive 020* and timelines for abandonment activities.

b) reviews offsetting wells for fluid containment to ensure hydraulic isolation of the CO_2 EOR storage reservoir, within a 1.6 km radius surrounding the proposed injection wells or the maximum expected fluid plume, whichever is larger.

The post-EOR risk assessment must include future use plans for the wellbore and address any changes made in the monitoring plan for life of the EOR scheme approval and into the post-EOR phase.

Records of risk assessments (including all iterative updates and comparisons of predicted behaviour of the sequestered CO_2 with measured performance) must be retained for the life of the scheme to support containment assurance plans and reclamation certificate applications.

Records demonstrating cement integrity, casing inspection, and hydraulic isolation log requirements in *Directive 051* may be needed to support the risk assessment.

Any high-risk offset wells within 100 metres of a proposed injection well may need to be abandoned as per *Directive 020*.

The AER may require additional wellbore risk assessment and enhanced containment standards through *Directive 020* abandonment if it deems such work necessary.

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16) A hazard assessment evaluating the potential for induced seismicity within the maximum CO_2 plume extent and the applied-for CO_2 EOR storage scheme approval area.

Assessment of pre-injection mitigation measures is an approach to avoid unacceptable induced seismicity.

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17) If induced seismic events or new hazards are identified once a CO_2 EOR storage scheme has commenced injection, the scheme operator must immediately contact the AER at Resources.Applications@aer.ca to propose a response and monitoring plan. The AER may amend scheme approval conditions with mitigations as needed.

The hazard assessment can be completed using established earthquake catalogues for the region, probabilistic seismic hazard analysis assessments produced for the province's injection wells, and publicly available data sources (e.g., Alberta Geological Survey, Earthquakes Canada).

Well Integrity, Suspension & Abandonment

Requirements

Directive 087, *Directive 013*, and *Directive 020* apply to CO_2 EOR storage schemes and wells.

18) Any SCVF/GM detected in wellbores in the CO_2 EOR storage area must be tested for the presence of CO_2 and listed as serious if the vent flow has CO_2.

19) Completed intervals must be abandoned to the Level A abandonment standards for containment of the stored CO_2.

Comments

Presence of CO_2 in the vent flow would indicate loss of containment and may have impacts on Alberta Environment and Protected Area's *TIER Quantification Protocol for the Geological Sequestration of Carbon Dioxide*.

Post-EOR, the scheme operator must ensure the stored CO_2 does not compromise the long-term integrity of well abandonments. At EOR termination, the remaining operating wellbores will need to meet the suspension requirements from *Directive 013* before being abandoned following the requirements for Level A as described in *Directive 020*.

Reporting

Requirements	Comments
20) Annual progress reports providing updates on scheme operation and at a minimum a) tables reporting CO_2 volumes injected monthly and annually per well and for the total scheme area, b) density of the injection fluid stream, c) CO_2 volume/mass produced and re-injected, d) net and gross CO_2 volumes injected, e) net CO_2 volumes stored in the reservoir, f) a discussion of the overall performance of the scheme, including the volume of incremental oil produced as a result of the CO_2 injection, g) updated CO_2 plume extent and pressure distribution models, and h) results and evaluation of all monitoring and testing done during the reporting period.	The scheme approval will outline a date by which annual progress reports and containment assurance plans are to be filed. Volumes must be reported in metric units.
21) Monthly reports to the AER via the Petroleum Information Network (Petrinex) on the density of the injection fluid stream.	

2.1.6 ER Related Processes

2.1.6.1 Reporting Requirements

Scheme performance reporting requirements, when necessary, will be detailed in the approval document. Typically, the AER only imposes reporting conditions when a novel technology or specific process is being used. Reporting requirements may include providing regular progress reports regarding scheme operation and performance.

2.1.6.2 Audit, Surveillance, and Enforcement

The AER may audit all new ER schemes and selected scheme amendments about 12 months after approval issuance. These audits will be conducted to

- confirm compliance with approval conditions,
- review scheme performance (actual versus predicted) to identify any issues, and
- validate data integrity.

If issues arise, the AER may request additional information or clarification from the approval holder, take appropriate enforcement action, and require corrective measures necessary to protect the oil and gas resource, equity, safety, and the environment.

In addition to the twelve-month audit, the AER may conduct surveillance on all provincial ER schemes on an ongoing basis. Random or targeted reviews may be conducted to ensure that compliance is met and that performance is consistent with expectations. If compliance or performance issues are identified, the AER will take appropriate enforcement action and require the approval holder to implement corrective measures.

2.2 Application for Concurrent Production

2.2.1 Background

Concurrent production (CCP) is defined as the production of an oil accumulation and its associated gas cap at the same time. Section 39(1)(e) of the *Oil and Gas Conservation Act* requires that no CCP scheme may proceed unless approved by the AER. CCP is a poolwide depletion decision requiring equitable treatment of all participants with productive wells.

2.2.2 When to Make This Application

If there is a need or desire to produce gas-cap gas either directly via a gas well or indirectly through oil zone perforations, application must be made to the AER.

CCP approval can take the form of one or more of the following:

- outright CCP that allows for production of gas-cap gas from both oil and gas wells
- CCP where gas may be produced through the oil zone perforations only
- CCP with a maximum gas withdrawal rate
- CCP with a maximum gas-oil ratio (GOR) above which the wells must be shut in
- CCP where only certain wells may be produced
- CCP for specific areas of a pool

2.2.3 Terms of Approval

A CCP application would likely be approved if the AER is satisfied that

1) gas-cap gas production would have a negligible impact on the ultimate oil recovery from the pool or that gas-cap gas production is unavoidable if oil is to be recovered from a given pool,
2) all gas production is or will be conserved, and
3) all potentially adversely affected parties in the pool agree with the proposed CCP scheme.

2.2.4 Requirements for an Application for Concurrent Production

Conservation

Requirements	Comments
1) Your geological interpretation of the pool involved, including a) oil and gas net pay isopach maps of the pool; b) where pool delineation or fluid interface locations are based on structural interpretation, a structure contour map of the pool and offsetting area; c) an interpreted and annotated log cross-section or representative well logs showing the i) stratigraphic interpretation of the zones of interest, ii) interpretation of the fluid interfaces present, iii) completions and treatments to the wellbores with dates, and iv) cumulative production.	
2) If you are applying for CCP through certain wells, a list of the wells proposed for CCP.	
3) A statement of whether you have attempted recompletion efforts to reduce gas-cap gas production. If yes, state the results. If no, explain why not.	Gas cap production from oil wells may be reduced or eliminated by reperforating the well lower in the zone.

4) Your evaluation of the oil and gas reserves for the pool, including a) an estimate of the initial oil volume and gas volume in place, b) an estimate of the oil and gas recovery factors under the existing depletion mechanism and under the proposed CCP depletion strategy, c) a description of the methods used in determining (a) and (b) above (e.g., material balance, volumetric analysis, model study, a comparison of analog pools), and d) the supporting data used in determining (a) and (b) above and the sources of the data (e.g., pressure/volume/temperature [PVT] properties and source, pressure data and source).	The stage of depletion of the pool may influence the AER's decision and should be discussed where appropriate.
5) An estimate of the current oil in place and gas in place and an estimate of the annual oil and gas production under CCP.	An understanding of the current stage of depletion of the subject pool and the future rate of depletion of the gas caps and the oil zone is key to evaluating the appropriateness of CCP for a pool.
6) An estimate of the gas cap segregation drive index, with supporting data and calculations.	Depending on its size relative to the associated oil pool, a gas cap can be a valuable source of pressure to the pool.
7) A discussion of planned operational changes, if any, for the subject pool (such as infill drilling).	Potential changes to a pool, such as infill drilling, pool expansion, and changes in production operations, can alter a pool significantly, and hence a decision on CCP would be deemed premature.

8) Comments as to the feasibility of enhanced oil recovery and gas cycling if there is a retrograde condensate gas cap in the subject pool.	A request for CCP is premature if enhanced recovery or gas cap cycling are feasible but have not been implemented in the pool.
9) Confirmation that all gas will be conserved; if this is not the case, a detailed discussion on the feasibility of gas conservation.	Except in cases where gas production is unavoidable, gas production would not generally be approved in the absence of gas conservation. Your evaluation of gas conservation should use the decision tree and economic decision process set out in AER *Directive 060*, sections 2.3 and 2.4. Under full gas conservation, only nonroutine flaring can occur. *Directive 060*, section 2.6, defines nonroutine flaring at conserving facilities and specifies operational requirements to minimize this flaring. Failure to address gas conservation in accordance with *Directive 060* may result in processing delays and deficiency requests.

Equity

Requirements	**Comments**
1) Documentation identifying notification to the unit operators, approval holders (if applicable), or well licensees in the AER-designated pool.	CCP applications often involve complex oil and gas equity issues. Failure to notify others involved in the pool will result in the return of your application.

2.3 Application for Pool Delineation and Ultimate Reserves

2.3.1 Background

The AER establishes pool boundaries (vertically and horizontally) and assigns reserves to all oil and gas pools in Alberta. These are shown in Pool Orders (G Orders), annual reserve publications, and individual well and pool files. Well licensees of new oil wells outside of established G Orders must submit a completed application for a New Well Base Allowable or Base MRL (O-38 form).

The initial oil volume or gas volume in place for new pools is often based on simple building-block assignment areas and wellbore parameters. Initially, recovery factors for new pools may be based on analog pools in the area. Initial delineation reflects early geological and pressure information. As the pools are developed and further well data and performance data are available, delineation and reserves may be adjusted to reflect this new information. Net pay isopach maps, material balance analyses, decline analyses, and analytical and numerical models may take the place of the simple building-block approach. Different pressure trends or new gas/oil or oil/water interface information may alter pool boundaries.

The interpretation of pool reserves and delineation can affect regulatory requirements related to the operation and development of oil and gas pools in Alberta, as well as equity-related issues between operators.

2.3.2 When to Make This Application

Following the initial well assignment and if additional information becomes available that substantially changes current decisions, a well licensee may choose to, and in fact is encouraged to, make an application to change assigned reserves or vary pool delineation for several reasons, including

- **conservation** (For example, new evidence may permit a restricted gas well to produce if it is no longer within a gas cap or the second well in a DSU.)
- **equity** (For example, new evidence supports delineation for a well to a pool with a higher MRL or GPP.)
- **future applications** (For example, while reserves evaluations are required in many other applications in this directive, an applicant may choose to file a standalone reserve application. Maintaining a common reservoir information base or understanding differences may assist or accelerate processing future applications for matters addressed in this directive.)
- **provincial records** (For example, pool boundaries and reserves are the foundation for conservation and equity protection.)

The AER monitors pool performance and interprets new well information. As a result, the AER may also request well licensees to file reserve submissions to update reserves for pools of provincial significance.

2.3.3 How the AER Processes the Application

Upon receipt of a standalone pool delineation or reserve application, the AER analyzes the new evidence, reviews the applicant's interpretation, and assesses potential alternatives.

These applications are considered a technical information submission, and as such there are no specific requirements to notify and discuss the different interpretations with other well licensees.

The AER may seek input on the delineation or reserve interpretation from well licensees in the area as part of the overall review and may hold a hearing into the matter. The AER will consider all input prior to rendering a decision. This decision may not agree with the applicant, who may reapply as additional information becomes available.

2.3.4 Requirements for an Application for Pool Delineation

Requirements	Comments
1) The data and your interpretation, if the basis for proposing a pool delineation change is a specific, definitive piece of evidence.	There may be a sharp contrast in performance between wells, such as distinctly different pressure data, that conclusively supports delineation changes. Building-block reserves may be split or adjusted to reflect new boundaries.
2) A detailed reserve submission, if the basis for proposing a pool delineation change is a composite of indicators.	Analysis of a set of data provides for identification of both supporting and refuting elements and a "best fit" decision.

2.3.5 Requirements for an Application for Ultimate Reserves

Requirements	Comments
1) Your geological interpretation of the pool, including a) a net pay isopach map of the pool, including both oil and gas if there is an associated pool; b) where pool delineation or fluid interface locations are based on structural interpretation, a structure contour map of the pool and offsetting area; c) an interpreted and annotated log cross-section or representative well logs showing the	Your application must provide a geological interpretation of the entire pool, not just the portion underlying lands you own. If it will help to clarify your basis for pool delineation or other aspects of your geological interpretation, you should submit a log cross-section containing wells both within and outside of the pool. As a minimum you must submit at least one representative well log from a well in the pool showing the information required in 1(c).
i) stratigraphic interpretation of the zones of interest, ii) interpretation of the fluid interfaces present, iii) completions and treatments to the wellbores, with dates, iv) cumulative production, v) finished drilling date and kelly bushing (KB) elevation, and vi) scale of the log readings; and d) a tabulation of your interpreted net pay, porosity, and water saturation for each well in the pool, along with the cutoffs, methodology, formulas, and constants used.	Your application will have fewer processing delays if you provide a clear picture of your geological interpretation, including the potential for further pool development.

2) Your evaluation of the oil and gas reserves for the pool, including

   a) an estimate of the initial oil volume and gas volume in place,

   b) an estimate of the oil and gas recovery factors,

   c) a description of the methods used in determining (a) and (b) above (e.g., material balance, volumetric analysis, model study, a comparison of analog pools), and

   d) the supporting data used in determining (a) and (b) above and the sources of the data (e.g., pressure/volume/temperature [PVT] properties and source, pressure data and source).

If there are sufficient pressure, production, and PVT data, a material balance evaluation should be done and compared to the volumetric results.

Failure to provide the calculation methods and supporting data will delay processing of your application.

It is not necessary to provide production plots for the wells, except to illustrate a particular point or issue (e.g., decline analysis, specific well performance issues).

Unit 3 Production Control

3.1 Commingled Production

3.1.1 Background

Commingled production occurs when two or more pools are produced without segregation in the wellbore. Commingled production is regulated in accordance with sections 3.050 and 3.060 of the *Oil and Gas Conservation Rules* (*OGCR*).

Segregation of production in the wellbore is regulated to

- avoid wellbore and/or reservoir conditions that may adversely affect resource recovery,
- maintain the ability to gather data on an individual-pool basis for resource evaluation and reservoir management,
- ensure operational safety, and
- ensure the protection of nonsaline groundwater.

While these reasons for segregated production remain valid, commingling of production from multiple pools in the wellbore following approval by the AER is a longstanding practice in Alberta that has occurred over a wide range of formations and depths. The AER recognizes that commingling maximizes conservation in many cases and is necessary for economic and orderly development of lower productivity resources.

Sections 3.1.5 and 3.1.6 of *Directive 065* allow commingling to occur without an application being filed or an AER approval being issued if the associated risk is low and specific requirements are met. For higher risk situations, if the commingling of production from two or more pools in the wellbore is desired, an application for approval to commingle must be submitted to the AER in accordance with section 3.1.8 of *Directive 065*.

3.1.2 Processes for the Management of Commingled Production

Three processes exist for the management of commingled production in the wellbore:

- development entity (DE),
- self-declared (SD) commingling, and
- approval of an application in accordance with *Directive 065*.

If the proposed commingling does not meet the requirements for commingling through the DE or SD process, the licensee must obtain approval for the commingling through the application process (figure 3.1 in section 3.1.4).

3.1.3 AER Expectations, Notification Requirements, and Compliance Assurance for All Commingled Production

3.1.3.1 Commingled Operations

The AER expects licensees to use good engineering practices when commingling production. This includes

- a good understanding of the reservoir and fluid properties prior to commingling;
- the collection of the appropriate reservoir data necessary to accurately assess and properly manage the reservoirs—this may exceed the minimum requirements prescribed by the AER; and
- review of all commingled wells and pools on an ongoing basis to ensure continued adherence to the requirements that originally supported the onset of commingled production.

Licensees must comply with all requirements set out in this directive and submit any additional data collected for reservoir management in accordance with section 11.005 of the *OGCR*.

The AER supports the water management objectives of Alberta's *Water for Life: Alberta's Strategy for Sustainability* and stresses that a licensee must meet the requirements in *Directive 035: Baseline Water Well Testing Requirement for Coalbed Methane Wells Completed Above the Base of Groundwater Protection* and *Directive 044: Requirements for the Surveillance, Sampling, and Analysis of Water Production in Hydrocarbon Wells Completed Above the Base of Groundwater Protection*.

3.1.3.2 Reporting and Administration of Commingled Production

The licensee must identify the process used to commingle production by selecting the appropriate item on the Petroleum Information Network (PETRINEX) drop-down list entitled "Commingling Process." The licensee must also update the commingling process in the event

- corrections to historical misuse of commingling process are required,
- a well no longer meets DE or SD commingling decisional tree criteria and commingling approval is reflected on a commingling (MU) order, or
- wellbore configurations have been changed (e.g., segregation or additional perforations expanding the completed interval).

If "MU Commingling Order" is selected as the "Commingling Process" in PETRINEX, then the associated MU order number must also be entered. (See section 5 of *Manual 011* for more details on PETRINEX and commingling.)

The temporary commingled code 999660 (TMP CMGL CODE) must be chosen when reporting commingled production for the first time regardless of the commingling process used. The DE and SD commingling codes will remain on the drop-down pool code listing for AER administration; however, these codes should not be selected to report commingled production.

The AER will evaluate all wells for which production is initially reported with a temporary commingled pool code. A commingled production code based on the geological evaluation of the pools completed in the well will then be assigned to the production by the AER to replace the temporary code for that well on the PETRINEX. However, where the DE or SD process has been used, the creation of this new commingled pool code does not imply that other wells completed in the same pools in the future may be commingled without further process. Each new well in which commingling is proposed through the DE or SD process must meet the DE or SD requirements, and production from the well must be reported to the PETRINEX initially using the temporary commingled pool code.

3.1.3.3 Data Collection

Data collection requirements associated with commingling under the various processes is set out in sections 7.025, 11.005, 11.070, 11.102, and 11.140 of the *OGCR* and in *Directive 040*.

The data collection requirements for gas production from coals and shales are set out in sections 11.005, 11.040, 11.070, 11.102, 11.140, and 11.145 of the *OGCR* and in *Directive 040*. Section 7.025 of the *OGCR* requires control wells for gas production from coals and shales. These control well requirements must be met by all licensees that have gas production from coals or shales.

3.1.3.4 Compliance Assurance

The AER has substantially strengthened its surveillance, audit, and enforcement processes to ensure that it is more effective in identifying and dealing with potential unauthorized commingling and other related noncompliant situations. Any noncompliance with commingled production requirements may result in a regulatory response from the AER.

The AER believes that it is prudent for licensees to proactively review their wells to ensure that all production operations are in compliance with the regulations and *Directive 065*. Licensees should disclose any instances of unauthorized commingling to ResourceCompliance@aer.ca.

The decision tree criteria for DE and SD commingling processes must be met for the life of the commingled stream. Licensees must review wells previously commingled using the DE and SD processes to ensure that the wells continue to meet the decision tree criteria.

In some compliance situations, pool designation may be an issue. The operator or licensee, as defined in the *Oil and Gas Conservation Act*, must comply with the current AER pool designation.

If the licensee wishes to present an alternative pool interpretation, it is expected to provide a technically sound assessment with supporting details.

Current AER pool designation information may be found on the official site for AER Field and Pool Orders at AER Home : Data & Publications : Orders : AER Order System. Field and pool orders are updated monthly.

Further information about pool designations can be obtained by contacting the AER by telephone at 403-297-8311 (Customer Contact Centre) or by email at PoolDesignation@aer.ca.

If there are questions regarding pool interpretations in a compliance situation, the AER will notify the licensee directly in writing. The licensee will have an opportunity to respond to new evidence or rulings on complex or unclear situations in four ways. The licensee may

- qualify to use the DE or SD process described in this section to restore compliance,
- segregate pools in the well,
- submit a complete commingling application under *Directive 065* requirements to restore compliance, or
- submit a technically supported pool delineation application in accordance with *Directive 065*.

Failure to respond within the specified timeframe to an AER request regarding noncompliance or pool delineation issues results in a regulatory response.

3.1.3.5 Notification Requirements for Commingling

A) Notice of Commingling When Using the DE or SD Process

There are no notification requirements associated with the DE or SD commingling processes.

Information on wells that are producing using the DE and SD commingling processes can be obtained by reviewing the list of wells located on the AER website, www.aer.ca, under Data & Publications : Orders : Commingling Orders. This list is updated daily.

As production without segregation in the wellbore may occur only from pools or zones that have common ownership within the drilling spacing unit, all ownership matters must be resolved before any commingling occurs. The licensee of the well in which commingling is occurring under the DE or SD process must also address any concerns that have been raised by Freehold mineral owners or licensees of wells offsetting the drilling spacing unit involved. The AER will continue to accept submissions from parties that have concerns about whether DE or SD commingling should have occurred, as noted in section 3.1.7.

Refer to the Explanatory Notes in section 3.1.7(7) for information on off-target well issues that may be raised for wells with production commingled using the DE or SD process and disputes regarding DE and SD commingling.

B) Notice of Commingling When Using the Application Process

Notification requirements when using the application process are outlined in the section "Resources Applications Notification Guidelines" in the preamble of this directive as well as in table 3.1. The applicant may be required to complete the notification requirements in more than one of the categories depending on the circumstances. The response period must be complete for all parties notified prior to the application for commingling being filed with the AER.

Consent from notified parties is not required. However, the AER expects applicants to engage in meaningful discussions with any stakeholder that has raised concerns or questions. The AER expects that applicants will make reasonable efforts to resolve matters prior to filing an application.

Table 3.1 Notification requirements for commingling applications

If you are applying for commingling because	You must send notice of the proposed commingling at minimum to
1) the proposed commingling is for a situation where • there is actual or anticipated water production equal to or greater than 30 m^3/month in a well with perforations above the base of groundwater protection (BGWP), or • there are unresolved equity issues with respect to the proposed commingling.	• well licensees of nonabandoned wells in the standard[1] DSU where the subject well is located and in the eight standard DSUs offsetting the subject well, and • Freehold lessors in the standard DSU where the subject well is located and in the eight standard DSUs offsetting the subject well.
2) the proposed commingling is for a situation where • the reservoir pressure of a pool or interval proposed for commingling exceeds 90 per cent of the lesser of the closure or breakdown fracture pressure of one of the other pools or intervals proposed for commingling, or • the well is in a designated oil sands area or is in a pool overlapping a designated oil sands area.	• well licensees of nonabandoned wells in the area of the smaller of the pools proposed for commingling and in the standard DSUs offsetting the smaller of the pools,[2] or if the smaller pool is a single-well pool, in the standard DSU where the subject well is located and in the eight standard DSUs offsetting the subject well, and • Freehold lessors in the area of the smaller of the pools proposed for commingling and in the standard DSUs offsetting the smaller of the pools, or if the smaller pool is a single-well pool, in the standard DSU where the subject well is located and in the eight standard DSUs offsetting the subject well.
3) the proposed commingling is for a situation where • the commingled stream contains H_2S, • the commingled stream contains oil, associated gas, and/or nonassociated gas, • there are two or more oil pools with production greater than 3 m^3/day from any well in any pool, • there is a pools subject to an existing or proposed enhanced recovery scheme, or • commingling of production would address an operational issue not specifically detailed in this directive.	• well licensees of nonabandoned wells in the pools proposed for commingling,[3] and • Freehold lessors in the area of the smaller of the pools proposed for commingling and in the standard DSUs offsetting the smaller of the pools, or if the smaller pool is a single-well pool, in the standard DSU where the subject well is located and in the eight standard DSUs offsetting the subject well.
4) the proposed commingling is for an area.	• well licensees of nonabandoned wells in the area of application and in the standard DSUs offsetting the area of application, and • Freehold lessors in the area of application and in the standard DSUs offsetting the area of application.

[1] For a gas well, a standard DSU is one section; for an oil well, a standard DSU is one quarter section. If the proposed commingling mixes oil and gas, notice must be provided for the larger DSU involved.

[2] Area of pool as defined by AER, or if the AER has not defined the pool when the notice is provided, the area of the pool as interpreted by the applicant. The AER may request the applicant to provide notice to additional parties if during the evaluation of the application the AER interprets the pool area to be larger than interpreted by the applicant.

[3] If a pool involved is extremely large, the applicant must make a judgement as to what area of the pool should be covered in the notification. This judgement would involve an assessment of which parties might be impacted by the proposed commingling. The AER may request the applicant to provide notice to additional parties if the AER considers that insufficient notice was provided.

3.1.4 Determination of Commingling Process to Use

A determination of which commingling process to use—DE, SD, or the application process—can be made using the decision tree in figure 3.1.

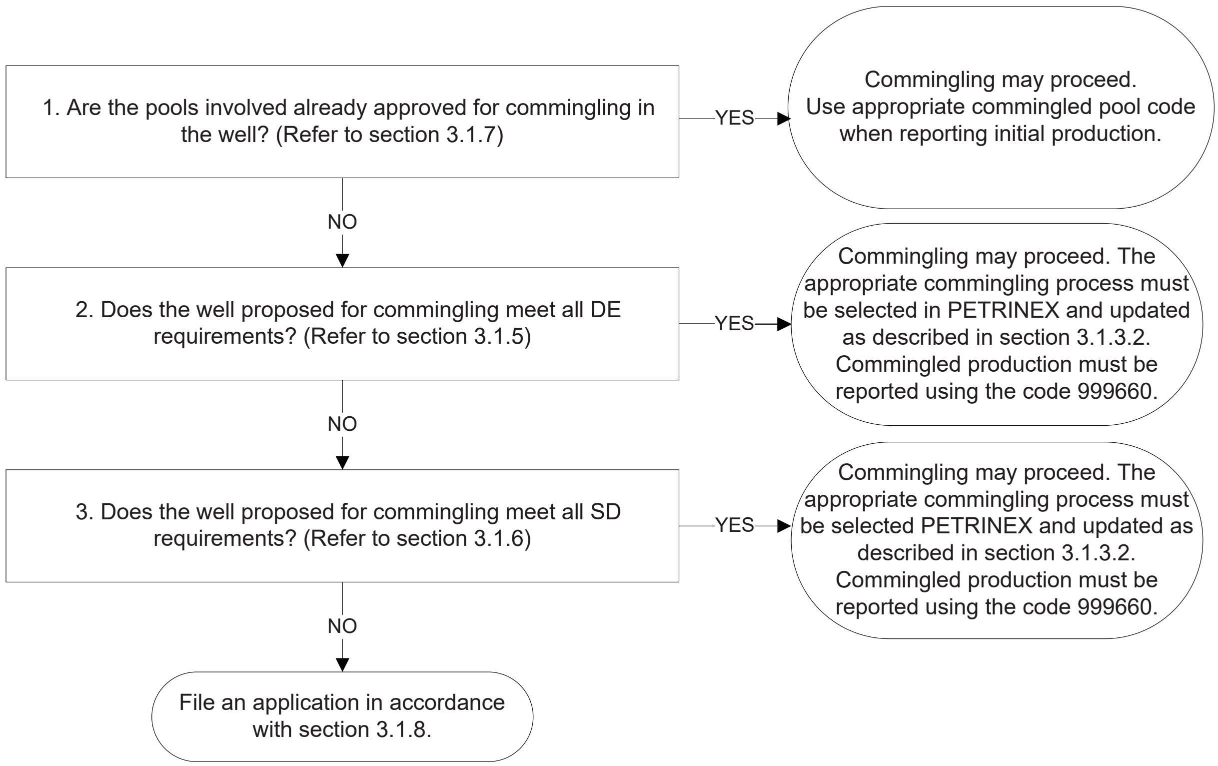

Figure 3.1 Decision tree to determine process to commingle production

3.1.5 Unsegregated Gas Production Within a DE

A DE is an AER-defined entity consisting of multiple stacked formations in a specific area where there is an adequate understanding of the resources to allow commingled production of these formations to be the standard development practice. The AER has established DEs where commingled production of multiple pools over a large area is already occurring and there is minimal risk that unsegregated production will negatively affect conservation or the environment. A DE is administered as a single commingled pool by the AER, although individual formation-based contributing pools within the DE will be identified on the AER order system. AER Orders No. DE 2006-1 and DE 2006-2 show the geographic area and stratigraphic intervals for the two DEs that have been established. These orders are available on the AER website, www.aer.ca, under Data & Publications : Orders : Commingling Orders.

If a licensee meets the requirements set out in section 3.051(1) of the *OGCR* and in this unit, unsegregated gas production from a DE may commence at a well without an application being filed or an AER approval being issued. Each well commingled in a DE must meet all DE requirements for the life of the commingled stream. The DE commingling process can be used for unsegregated production only and does not apply to non-producing wellbores. That is, a well that has been identified as using the DE process for commingling cannot be initially completed and left with pools unsegregated in the wellbore without production commencing. Licensees must identify the well as using the DE commingling process, in accordance with section 3.1.3.2 of this directive; any unsegregated production must be reported using the temporary pool code 999660.

Data requirements for wells with production commingled in the wellbore under the DE process include those set out in sections 11.005, 11.070, 11.102, and 11.140 of the *OGCR* and in *Directive 040: Pressure and Deliverability Testing Oil and Gas Wells—Minimum Requirements and Recommended Practices*.

The data collection requirements for gas production from coals and shales are set out in sections 11.005, 11.040, 11.070, 11.102, 11.140, and 11.145 of the OGCR and in *Directive 040*. Section 7.025 of the *OGCR* requires control wells for the production of coalbed methane (CBM) and shale gas. These control well requirements must be met by all licensees that have gas production from coals or shales.

3.1.5.1 Requirements for Commingling of Gas Production in a DE

The following are the specific requirements set out in section 3.051(1) of the *OGCR* that must be met before **nonassociated gas** production may be undertaken without segregation in the wellbore under the DE process:

1) There are no unsegregated completions above or below the stratigraphic interval of the DE.
2) Anticipated or actual water production is less than 30 m^3/month if there are completions above the base of the BGWP.
3) There is no H_2S in the production stream.
4) The licensee has resolved any concerns of lessors or lessees of the mineral rights whose rights may be directly and adversely affected by the unsegregated production.
5) The reservoir pressure of any interval completed for production does not exceed 90 per cent of the fracture pressure of any other interval completed for production.
6) There is no production of gas associated with an oil accumulation.

For additional information, refer to the decision tree in figure 3.2 and the explanatory notes in section 3.1.7.

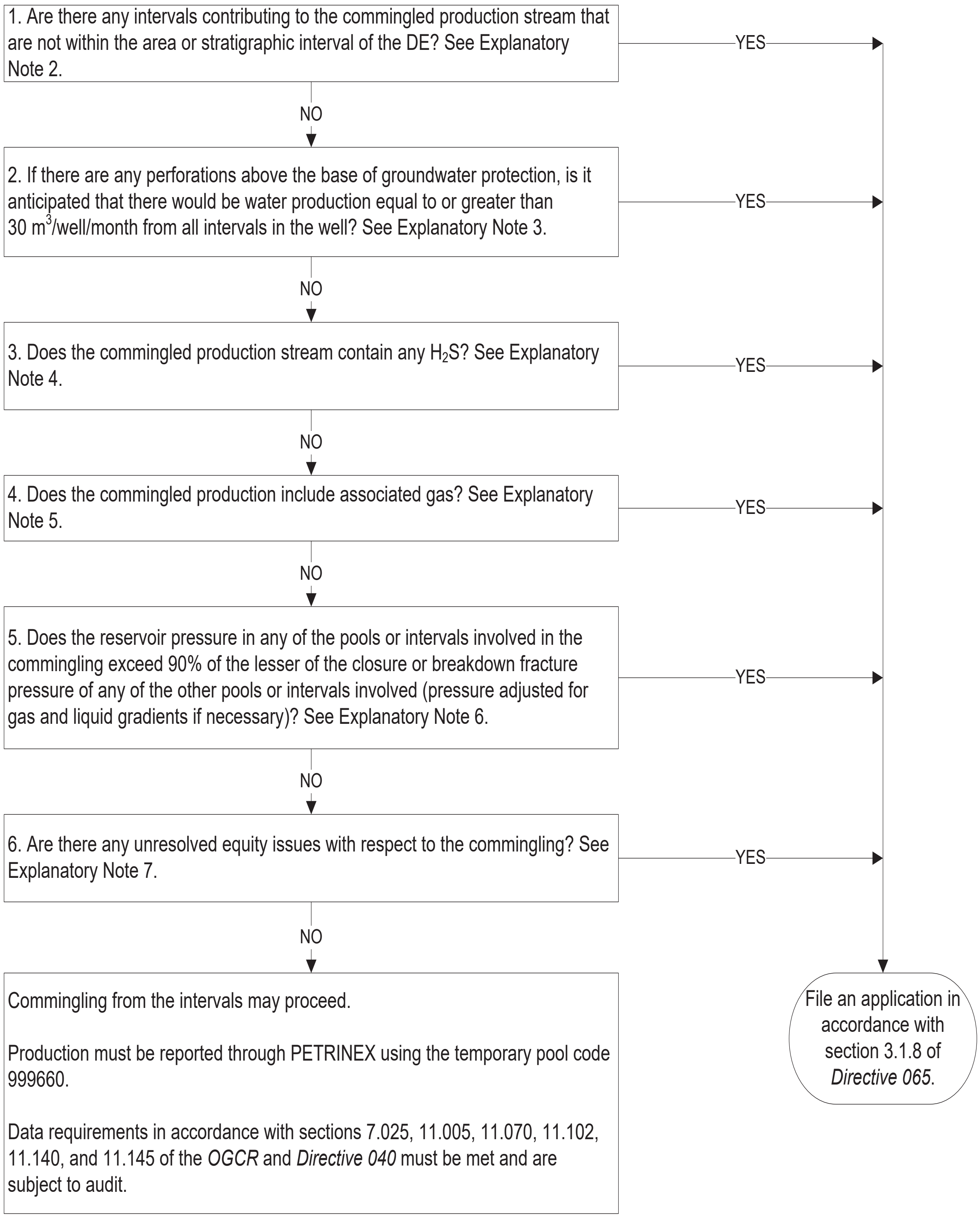

Figure 3.2 Decision tree for the commingling of gas production from intervals within a development entity (DE)

3.1.6 SD Unsegregated Production

If a licensee meets the requirements set out in sections 3.051(2) and (3) of the *OGCR* and in this unit, unsegregated gas production may commence using the SD process without an application being filed or an AER approval being issued. Each well commingled using this process must meet all SD requirements for the life of the commingled stream. The SD commingling process can be used for unsegregated production only and does not apply to non-producing wellbores. That is, a well that has been identified as using the SD process for commingling cannot be initially completed and left with pools unsegregated in the wellbore without production commencing. Licensees must identify the well as using the SD oil or SD gas commingling process, in accordance with section 3.1.3.2 of this directive; any unsegregated production must be reported using the temporary pool code 999660.

The SD process is for commingling of production from gas pools only or oil pools only. Commingled production from gas and oil pools in the same wellbore is not permitted under this process and requires a commingling application. The SD commingling process has limited applicability with respect to oil production at present, being available for use with only very low-rate oil wells. Also, the SD process may not be used if the proposed commingling involves any H_2S, or wells in a designated oil sands area or in a pool that overlaps into a designated oil sands area.

Production from a well completed within a DE may be commingled with production from intervals above or below the stratigraphic intervals of the DE using the SD process, provided that all requirements for SD commingling are met.

Data collection requirements associated with commingling under the SD process are set out in sections 11.005, 11.070, 11.102, and 11.140 of the *OGCR* and in *Directive 040*. The SD commingling process is the same for all situations, but well testing requirements vary for gas wells depending on the well flow rate, as set out in *Directive 040*.

3.1.6.1 Requirements for SD Commingling of Gas Production

The following are the specific requirements set out in section 3.051(2) of the *OGCR* that must be met before *nonassociated gas* production may be undertaken without segregation in the wellbore under the SD process:

1) Anticipated or actual water production is less than 30 m^3/month if there are completions above the base of the groundwater protection.

2) There is no H_2S in the production stream.

3) The licensee has resolved any concerns of lessors or lessees of the mineral rights whose rights may be directly and adversely affected by the unsegregated production.

4) The reservoir pressure of any interval completed for production does not exceed 90 per cent of the fracture pressure of any other interval completed for production.
5) There is no production of gas associated with an oil accumulation.
6) The well is not in a designated oil sands area or in a pool that overlaps a designated oil sands area.
7) The pools or intervals are not subject to any existing or proposed enhanced recovery scheme.

For additional information, refer to the decision tree in figure 3.3 and the explanatory notes in section 3.1.7.

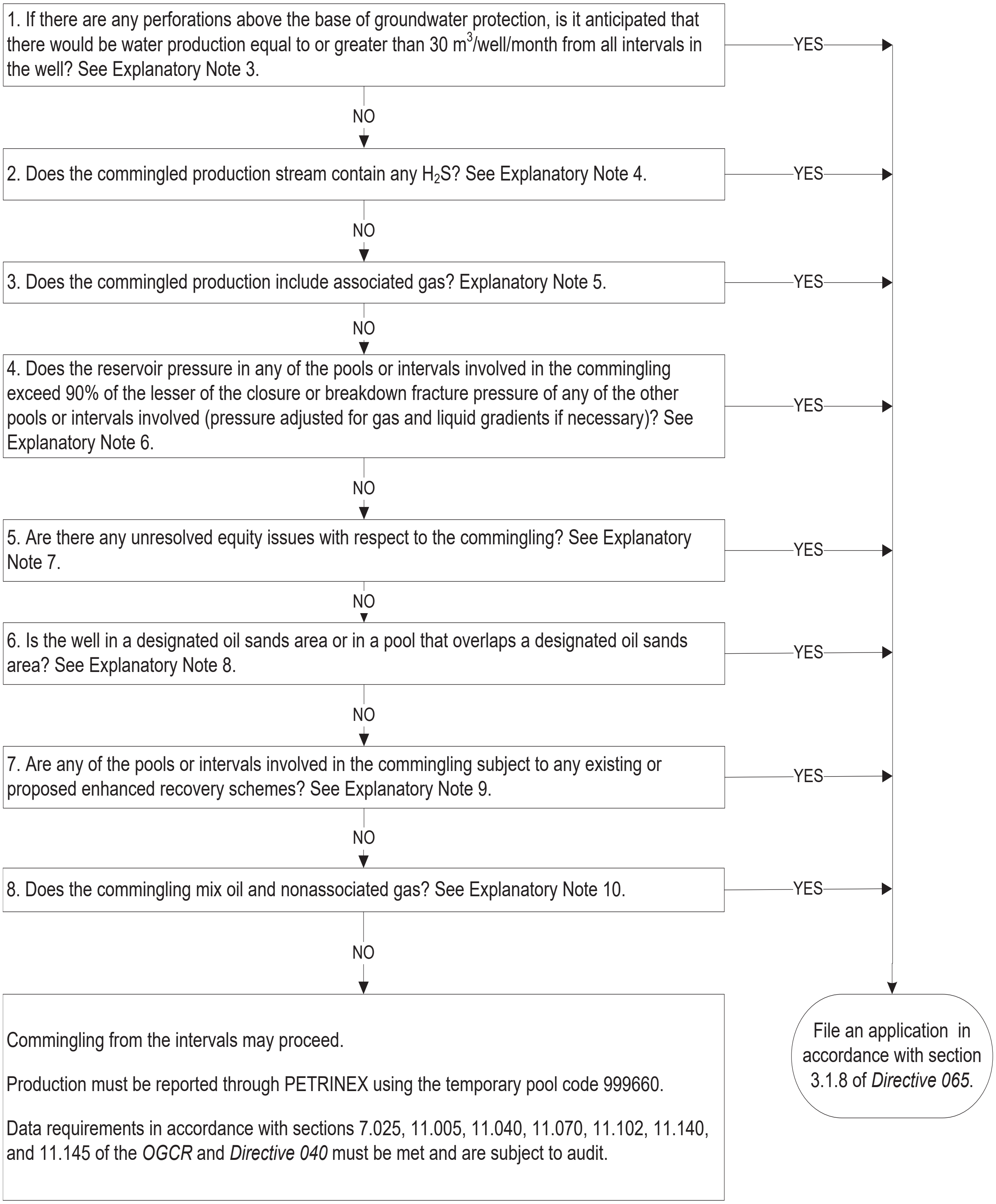

Figure 3.3 Decision tree to determine if the proposed commingling is a candidate for self-declared gas commingling in a well

3.1.6.2 Requirements for SD Commingling of Oil Production

The SD commingling process has limited applicability with respect to oil production at present, being available for use with only low rate oil wells. Also, while the commingling of oil production under the SD process is on a well-by-well basis, as it is for all SD commingling, the production rate of all other oil wells in the pools involved with the SD commingling must be taken into consideration, as noted in requirement 10 below, prior to proceeding with using the SD process for the commingling of oil production. This measure is in effect to ensure that resource conservation issues associated with higher productivity oil pools are considered through an application in accordance with section 3.1.7 prior to commingling commencing in the pools.

A licensee must meet the following requirements set out in section 3.051(3) of the *OGCR* before oil production may be undertaken without segregation in the wellbore under the SD process:

1) Anticipated or actual water production is less than 30 m^3/month if there are completions above the BGWP.
2) There is no H_2S in the production stream.
3) The licensee has resolved any concerns of lessors or lessees of the mineral rights whose rights may be directly and adversely affected by the unsegregated production.
4) The reservoir pressure of any interval completed for production does not exceed 90 per cent of the fracture pressure of any other interval completed for production.
5) The well is not in a designated oil sands area or in a pool that overlaps a designated oil sands area.
6) The pools or intervals are not subject to any existing or proposed enhanced recovery scheme.
7) There is no production of gas that is not associated with an oil accumulation.
8) The oil pools have the same rate administration.
9) There are no oil pools that have associated gas caps that have not been approved for concurrent production.
10) The unsegregated flow rate of every well in the pools proposed for commingling is less than 3 m^3/day when calculated over three consecutive months of production.
    - [Total production for 3 consecutive months] ÷ [Total hours on production during those 3 months] × [24 hours/day] must be less than 3.0 m^3/operating day, **and** the flow rate of each well in the pools involved with the SD commingling must also be less than 3.0 m^3/operating day when calculated in the same manner.

For additional information, refer to the decision tree in figure 3.4 and the explanatory notes in section 3.1.7.

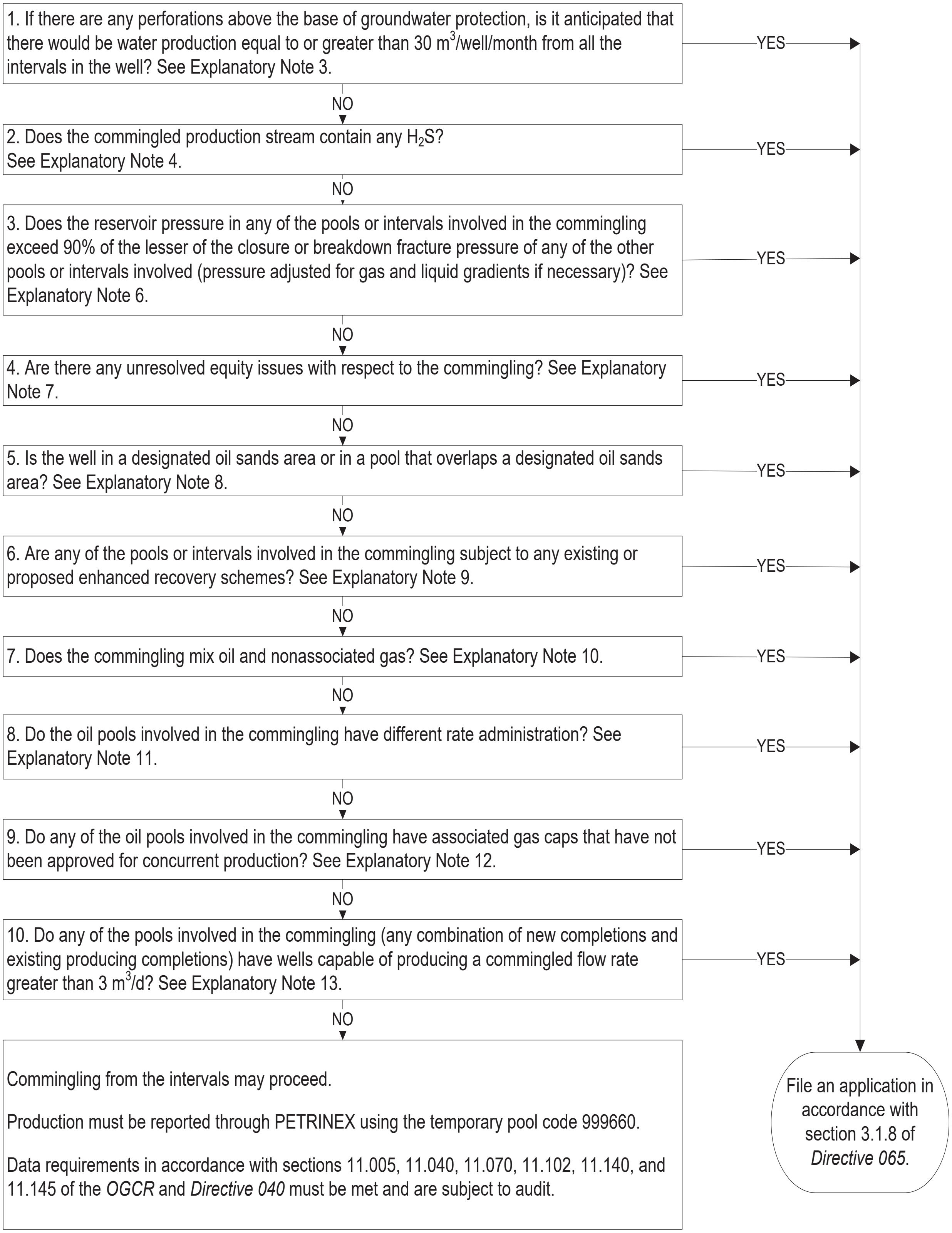

Figure 3.4 Decision tree to determine if the proposed commingling is a candidate for self-declared oil commingling in a well

3.1.7 Explanatory Notes to Determine if the DE or SD Processes May Be Used

1) *Are the pools involved already approved for commingling in the well?*

To answer this question, the list of pools approved for commingling, as identified in the field-based MU orders, must be checked. An evaluation needs to be made as to whether each productive interval in the well proposed for commingling is currently part of an existing pool as defined by the AER. If each interval proposed for commingling is within the boundaries of existing pools as defined at the time the licensee is conducting its evaluation and these pools are already approved for commingling, production from the pools may be commingled in the subject well without any notice to the AER. Commingled production must be reported to the PETRINEX using the existing commingled production code for the pools involved.

If at the time of the evaluation, the pools in the well have not been approved for commingling as set out in the field-based MU orders, the licensee may proceed to use the DE or SD decision tree to determine whether the well is a candidate for commingling through the DE or SD process. If the well is a candidate for commingling using the DE or SD process, production may be commingled in the wellbore immediately. Commingled production must initially be reported to the PETRINEX using the temporary commingled pool code 999660 for each field, and the licensee must operate within the DE and SD criteria at all times. If the proposed commingling does not meet the criteria for either DE or SD commingling and commingling is desired, an application in accordance with section 3.1.8 of *Directive 065* must be submitted.

2) *Are there any intervals contributing to the commingled production stream that are not within the area or stratigraphic interval of the DE?*

To answer this question, the licensee must confirm if the well and intervals proposed for commingling are within the area and stratigraphic interval of the related DE. This information is provided on the order for each DE, which is available on the AER website, www.aer.ca, under Data & Publications : Orders : Commingling Orders. If the well is outside the area of the DE or there are any perforated intervals within the wellbore that are outside the stratigraphic interval of the DE, the well is not permitted to commingle production under the DE process. If commingling of production is desired in this circumstance, the licensee may proceed to the SD decision tree and determine if the proposed commingling meets the criteria for SD commingling. If the proposed commingling does not meet the criteria for either DE or SD commingling and commingling is desired, an application in accordance with section 3.1.8 of *Directive 065* must be submitted.

3) *If there are any perforations above the BGWP, is it anticipated that there would be water production equal to or greater than 30 m^3/well/month from all intervals in the well?*

A licensee may determine whether any interval proposed for commingling is above BGWP from the data provided in AER *ST55: Alberta's Base of Groundwater Protection (BGWP) Information*.

The volume of 30 m^3/well/month is proposed as a practical cutoff to allow for small volumes of water, including water of condensation that may periodically need to be cleaned out of the well.

If it is anticipated that water volumes equal to or greater than 30 m^3/well/month could be produced from any or all intervals in the well that has perforations above the BGWP, a licensee may not commingle production using the DE or SD process. If the well begins to produce equal to or greater than 30 m^3/well/month after the commencement of commingled production, the licensee must immediately self-disclose to the AER (see section 3.1.3.4).

If an existing well that is to be recompleted for commingled production has produced greater than 30 m^3/well/month of water from the well in any of the last 12 months, a licensee may not commingle production using the DE or SD process.

If the licensee wishes to commingle production in this circumstance, an application in accordance with section 3.1.8 of *Directive 065* must be submitted. The application must provide a case that water produced with commingled production will not contaminate groundwater or adversely impact the recovery of gas from coals. Licensees should note that commingling of production in wells with completions above the BGWP that have actual or anticipated water production equal to or greater than 30 m^3/month conflicts with *Directive 044*.

Licensees must also ensure that operations comply with the *Water Act* taking particular note that non-saline water may not be produced without a groundwater diversion permit, non-saline aquifers may not be mixed, and saline and non-saline aquifers may not be mixed.

4) *Does the commingled production stream contain any H_2S?*

Gas or oil with any H_2S content greater than 0.00 mole/kilomole is considered to contain H_2S. This is consistent with table 7.1 in *Directive 056: Energy Development Applications and Schedules*.

A licensee may not commingle gas or oil production containing H_2S using the DE or SD process. If commingling of production is desired in this situation, an application in accordance with section 3.1.8 of *Directive 065* must be submitted. If H_2S is detected subsequent to the commencement of DE or SD commingling, the decisional tree criteria are no longer being met and **licensees must immediately self-disclose to the AER**.

5) *Does the commingled production include associated gas?*

Commingling of associated gas and nonassociated gas may not occur using the DE or SD (gas) process. If the licensee wishes to commingle any nonassociated gas with associated gas, an application in accordance with section 3.1.8 of *Directive 065* must be submitted.

6) *Does the reservoir pressure in any of the pools or intervals involved in the commingling exceed 90 per cent of the lesser of the closure or breakdown fracture pressure of any of the other pools or intervals involved (pressure adjusted for gas and liquid gradients if necessary)?*

Closure pressure is the pressure needed to open and/or extend a fracture resulting from previous stimulation operations. Breakdown pressure is the pressure needed to initially fracture a reservoir during stimulation operations.

Having extreme pressure differences between pools proposed for commingling raises a safety issue in that wellbore control may be jeopardized if fluid from a high-pressured reservoir flows into a lower-pressured reservoir that has a well completion or wellhead equipment not designed for such high pressures. Another concern about the commingling of production from pools with extreme pressure differences arises when a new well is drilled into a pool that has an unusually high pressure due to cross-flow from a commingled completion; this raises a safety issue in that the party drilling nearby may not anticipate the higher pressure.

The onus is on the licensee to evaluate this issue. If the reservoir pressure in any of the pools proposed for commingling exceeds 90 per cent of the lesser of the closure or breakdown fracture pressure in any other pools proposed for commingling (with pressure adjusted for gas and liquid gradients in the wellbore if necessary), a licensee may not commingle gas in the wellbore without the specific approval of the AER through an application filed in accordance with section 3.1.8 of *Directive 065*. Any application requesting approval for commingling in this situation must show that the pools involved will be isolated during any shut-in periods and that casing and cement integrity and wellhead design are adequate for the proposed completion.

7) *Are there any unresolved equity issues with respect to the commingling?*

Although there are no notification requirements associated with the DE and SD processes, well licensees must ensure that there is common ownership within a drilling spacing unit before any production occurs. Licensees should also be aware that well spacing may not be the same for all zones.

Licensees using the DE and SD commingling processes in off-target wells should also be aware that commingling may be an issue because commingling will affect the licensee's ability to obtain segregated pool data, which in turn may adversely affect the ability of offsetting licensees to determine the possible effects of the off-target well. For example, the offsetting licensee may not be able to adequately judge whether the off-target well is in the same pool as the offsetting licensee's well because of a lack of segregated pool data.

If a licensee is considering drilling an off-target well and is also considering commingling production in the wellbore from the onset, it is recommended that the licensee determine in advance whether such commingling is likely to be an issue with any offsetting mineral holder with a wellbore, so that the question on equity on the decision trees can be adequately answered.

If there is commingling in an off-target well and subsequently a dispute arises respecting the off-target well, the AER may require the licensee to segregate production from the pools in question so that data can be obtained to resolve the dispute.

If a party has a concern as to whether the commingling should have occurred, it must contact the licensee of the well in which the commingling is occurring. The parties should attempt to resolve the issue through negotiation, appropriate dispute resolution, and other mutually acceptable means. If the dispute is not resolved, either party may contact the AER for resolution. After review of the matter, the AER may require that production in the well under dispute be segregated.

Although it would normally be expected that any concerns raised regarding commingling would be brought forward by Freehold mineral lessors or licensees with an interest in the drilling spacing unit where commingling is to occur or in an adjacent drilling spacing unit, concerns raised by parties outside of that area must also be addressed. If the AER were asked to make a decision in such a case, it would consider the arguments brought forward on their own merits and would not automatically reject the concerns raised solely due to the location of the objecting party's interests.

8) *Is the well in a designated oil sands area or in a pool that overlaps a designated oil sands area?*

The licensee must check AER Orders No. OSA 1, OSA 2, and OSA 3 showing designated oil sands areas and strata. These orders are available on the AER website, www.aer.ca, and from AER Information Services. Because the issue of gas production in oil sands areas can be complex and the optimum processes for dealing with the production of gas reservoirs in contact with bitumen reserves have not been determined, wells in this area are not candidates for SD commingling. If approval to commingle gas production in a designated oil sands area or from any pool that overlaps a designated oil sands area is desired, an application in accordance with section 3.1.8 of *Directive 065* must be submitted.

9) *Are any of the pools or intervals involved in the commingling subject to any existing or proposed enhanced recovery scheme?*

Conservation may be jeopardized if any pool proposed for commingling is part of an enhanced recovery scheme. The lack of segregation could result in operational difficulties and the loss of data required to properly manage the scheme. In this situation, SD commingling may not occur. If approval to commingle production is desired, an application in accordance with section 3.1.8 of *Directive 065* must be submitted.

10) Does the commingling mix oil and nonassociated gas?

Conservation of oil may be jeopardized if there is commingling of oil and nonassociated gas. The lack of segregation could make it difficult to determine if the oil pool is a candidate for enhanced recovery. In this situation, SD commingling may not occur. If approval to commingle is desired, an application in accordance with section 3.1.8 of *Directive 065* must be submitted.

11) Do the oil pools involved in the commingling have the same rate administration?

Oil pools proposed for commingling must have a common rate administration. This means that all pools have been approved for good production practice (GPP) or, alternatively, that all wells in the pools are subject to a maximum rate limitation (MRL). The MRLs can be different for the wells.

If commingling is desired for pools with different rate administration, the well licensee's first step must be to file an application requesting the same rate administration for all pools involved (i.e., all pools are either approved for GPP or all pools are subject to MRL). If the AER approves the application to establish the same rate administration, the well licensee may then review the wells and pools involved to determine if commingling may occur under the SD process. If the wells and pools still do not meet all the SD criteria and approval to commingle in this situation is still desired, an application in accordance with section 3.1.8 of *Directive 065* must be submitted.

12) Do any of the oil pools involved in the commingling have associated gas caps that have not been approved for concurrent production?

If commingling is desired for any pool with a gas cap that has not been previously approved by the AER for concurrent production, the well licensee's first step must be to file an application requesting approval of the appropriate concurrent production. If the AER approves the application for concurrent production, the well licensee may then review the wells and pools involved to determine if commingling may occur under the SD process. If the wells and pools still do not meet all the SD criteria and approval to commingle in this situation is still desired, an application in accordance with section 3.1.8 of *Directive 065* must be submitted.

13) Do any of the [oil] pools involved in the commingling (any combination of new completions and existing producing completions) have wells capable of producing a commingled flow rate greater than 3 m^3/day?

Pools that have wells capable of producing a commingled flow greater than 3 m^3/day are considered to be potential enhanced recovery candidates.

For each existing segregated producing oil pool, the rate must be determined while the well is producing in a pumped-off fashion. The rate must be an average of the last three months of production, calculated using operating hours; the three months need not be consecutive, nor is there a minimum time for production in a given month. All wells in the pools must be reviewed to ensure that there are no wells capable of producing a commingled flow rate greater than 3 m^3/day.

For a new oil pool/well, the anticipated production rate must be determined from test data collected from the oil zones in the well.

If approval to commingle in this situation is desired, an application in accordance with section 3.1.8 of *Directive 065* must be submitted.

This decisional criterion must be met for the life of the commingled stream. This means that any remedial operations on wells to increase productivity or any expansion of the pool that adds higher productivity wells may place the SD commingled wells in noncompliance (see section 3.1.3.4 of this directive).

3.1.8 Approval to Commingle Production Through an Application

If the proposed commingling does not meet the criteria to allow commingling through the DE or SD processes and is not already approved for the pools in question, the licensee must obtain approval for commingling through the application process. The licensee must file an application in accordance with section 3.050 of the *OGCR* and section 3.1.8 of *Directive 065*. The application may request commingling on a well, pool, or area basis.

For wells, pools, or areas applied for under this process, the intervals applied for commingling must remain segregated until the AER has issued an order approving the application.

In summary, the application process may be used to obtain approval to commingle production in accordance with section 3.050 of the *OGCR* if the proposed commingling is not permitted through the DE or SD process. In addition, applications may be made for area-based commingling; however, area-based applications should only be submitted for areas and strata that do not qualify for the DE or SD process.

3.1.8.1 How to Make a Commingling Application

Submit applications electronically, rather than on paper, using the Electronic Application Submission (EAS) process, accessed through the Digital Data Submission (DDS) screen on the AER website, www.aer.ca. The AER will review all applications to ensure that the requirements for commingling applications have been met. Incomplete applications or those containing significant errors will be closed.

3.1.8.2 How the AER Processes the Application

The AER reviews all commingling applications to ensure that oil and/or gas recovery will be optimized, there will not be any adverse effects from the commingling, safety is maintained, and non-saline groundwater is protected.

The AER will disposition applications electronically, with the disposition being available for viewing through IAR Query for 30 days after the disposition of the application. IAR Query is accessible via the Systems & Tools page on the AER website.

3.1.8.3 Requirements for an Application for Commingled Production on a Well, Pool, or Area Basis

The requirements for all situations where commingling may be desired are numbered and described later in this section. The information required for any specific commingling application will depend on the reasons that the application is being made. Table 3.2 shows the numbered requirements that must be met in each of the situations noted. Depending on the situation, the applicant may be required to choose more than one of the categories and meet the combined requirements in the application.

If the proposed commingling includes gas from coal or shale, an applicant must file an application for approval of commingling on an area basis, rather than for a well or pool-based approval. An area-based approval can include one or more DSUs. Applications should be formatted so that the number of the requirement in table 3.2 corresponds with the numbered discussion in the application.

Table 3.2 Summary of requirements for commingling on a well, pool, or area basis

Reason for filing a commingling application	Requirements for applications
1) There is actual or anticipated water production equal to or greater than 30 m^3/month in a well with perforations above the BGWP.	1, 2(a), 2(b)(i), 3–7, 9, 10–14
2) There is H_2S in the proposed commingled production stream.	1, 2(a), 2(b)(ii), 3, 4, 7–14
3) The proposed commingling is for • nonassociated and associated gas, • oil and nonassociated gas, • oil, associated gas, and nonassociated gas, or • oil pools (any combination of new completions and existing producing completions) having wells capable of producing a commingled flow rate more than 3 m^3/day.	1, 2(a), 2(b)(iii), 3, 4, 10–14, 17
4) The reservoir pressure of a pool or interval proposed for commingling exceeds 90 per cent of the lesser of the closure or breakdown fracture pressure of one of the other pools or intervals proposed for commingling.	1, 2(a), 2(b)(iv), 3, 4, 10–13, 15
5) There are unresolved equity issues with respect to the proposed commingling.	1, 2(a), 2(b)(vi), 3
6) The well is in a designated oil sands area or is in a pool overlapping a designated oil sands area.	1, 2(a), 3, 4, 10–14, 18
7) A pool proposed for commingling is subject to an existing or proposed enhanced recovery scheme.	1, 2(a), 2(b)(v), 3, 4, 10–14, 16
8) Area-based commingling is desired.	1, 2(a), 2(b)(vi), 3, 4, 7, 10–14, 19
9) Commingling of production would involve an operational issue not specifically detailed in *Directive 065*.	All requirements are to be included in the application. For any requirement not applicable to the situation, the applicant must indicate that the requirement does not apply.

An application for approval to commingle production must include the information for those items as specified in the table above and as described on the following pages.

Requirements	Comments
1) A statement of what is being requested, including	
a) a reference that the application is being made under section 3.050 of the *OGCR*, and	
b) if approval for commingling is requested on a well or pool basis, the name of the wells and pools that are the subject of the application, together with identification of each productive interval (kelly bushing [KB] elevation, in metres) in each well of interest from which you propose to commingle production, or	If the pools involved have not been defined by the AER at the time of application, the pools should be referred to as undefined. Inclusion of the intervals ensures that there is no confusion about the pools involved, which might occur if the AER and an applicant have different terminology for the same zones.
c) if an area-based commingling approval is being requested, a list of the sections in the area of application and the zones to which the commingling would apply, together with a geophysical log of a type well with annotations identifying the subject zones.	
2) A discussion of the reasons why you are requesting commingling, including, as appropriate,	In general, improved economics with commingling alone or the ability to conduct fewer tests under a commingling approval are not considered valid reasons for an application.
a) a statement of the DE or SD criteria that were not met or the operational issues that would be addressed by commingling, and	
b) justification as to why commingling should be granted, including, where required,	Your discussion of why commingling should be permitted should draw on the information and evaluations included elsewhere in the application.

i) why commingling will not contaminate any non-saline water interval, with supporting technical evaluation as appropriate,

ii) why commingling of the sour gas will not cause problems, including contamination of sweet pool, with supporting technical evaluation,

iii) why commingling will not adversely impact recovery from the oil pool, with supporting technical evaluation,

iv) why the differences in pressure between the pools will not be a safety issue if commingling is permitted, with supporting technical evaluation; provide an explanation of why the higher pressured zone/s cannot be produced first so that the pressure depletion will allow the addition of lower pressured zones at a later date,

v) why the commingling will not adversely impact the operation of the enhanced recovery scheme, with supporting technical evaluation, or

vi) why the commingling will not have any adverse impacts, with supporting technical evaluation.

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3) A description of your notice program, including	Notification requirements are set out in table 3.1.
a) lists of the parties notified,	You must provide a tabulation of Freehold owners and well licensees notified. The tabulation should include the legal land description by DSU for the area of notification and the names of the mineral owners, except as noted below, and well licensees contacted for each DSU. The tabulation must not include the names of individual Freehold mineral owners, as this might raise privacy issues. For these persons, the tabulation should specify “Freehold – Individual.” You must compile a list of the names, legal description of the land involved, and mailing addresses of all Freehold mineral owners notified and have this information available to the AER on request. As this list contains personal information, it is *not* to be filed upon submitting the application to the AER.
b) evidence of notification, and	Provide a written statement that all of the Freehold mineral owners and well licensees as required by table 3.1 have been notified. Provide an example of the notification letter sent to individual Freehold mineral owners and to well licensees. Do not include any individual’s name or contact information in the example of the letter sent to Freehold mineral owners. Do **not** provide copies of any notification letters that were sent unless specifically requested by the AER.

c) summary of notification results.	Provide a statement of the results of your notification program. The AER does not require letters of consent from the parties notified. Do **not** file copies of any consent letters that may have been received unless requested to do so by the AER. You must include the details of unresolved concerns, both written and verbal, in the application filed with the AER. Include a discussion of how you have addressed the unresolved concerns and the outcome you expect from the AER regarding the unresolved concerns. If an unresolved concern is from an individual Freehold mineral owner, do not include the person's name, contact information, or written correspondence. In these cases the person must be identified as "Freehold – Individual" in the application. You must have the name, contact information, and written correspondence from such individuals available to the AER on request. If a substantiated, valid statement of concern is filed that cannot be resolved by the parties involved in a reasonable time, the AER will typically schedule a public hearing to consider the application.
4) If there are perforations above 600 mKB, identification of the base of groundwater protection (BGWP) (mKB).	The BGWP may be obtained from the data provided in AER *ST55-2007: Alberta's Base of Groundwater Protection (BGWP) Information* or from your own analysis. If you have completed your own analysis, you must include the geological and/or technical information to support your pick of the BGWP in the application.

5) a) Identification of the source (intervals), composition, and volumes of the water, and b) a discussion of how anticipated water production was estimated or how produced water was measured or estimated.	You must conduct sampling and analysis of the water in accordance with *Directive 044*. Well licensees are responsible for ensuring that the volume of water produced from a well is measured accurately.
6) If the applicant is proposing to produce non-saline water, the number of the water diversion permit that has been obtained from Alberta Environment and Protected Areas.	The *Water Act* prohibits the production on non-saline water unless such production is approved by a water diversion permit obtained from Alberta Environment and Protected Areas.
7) A copy of the fluid analysis for each pool, coal zone, and shale zone proposed for commingling.	
8) Confirmation that the infrastructure to produce and transport the reservoir fluid is appropriate for the commingled production stream.	
9) All production operations that contain fluids with any H_2S must meet the requirements of *Directive 071: Emergency Preparedness and Response*.	If you believe that an updated ERP is not necessary, your discussion must indicate why you believe that is the case.
10) A discussion of the geology of the pools, coal zones, and shale zones involved in the application.	Knowledge of the geological setting for a pool/zone can add insight as to the quality of the pool/zone (for example, a reservoir matrix that would result in poor permeability and/or poor productivity) and the likelihood that the pool/zone may be extensive (e.g., the depositional environment, the trapping mechanism).

11) For all types of reservoirs excluding coal or shale reservoirs, your interpretation of each pool involved in the application, including

a) a net pay isopach map of the pool, including both oil and gas if there is an associated pool,

b) if pool delineation or fluid interfaces are based on structural interpretation, a structure contour map of the pool and offsetting area, and

You do not have to include net pay isopach maps if the pools are considered to be single well; however, you should explain why the pools are considered to be single-well pools and whether this is based on offset well control and/or engineering data.

If the size of the pool is unknown due to poor well control, the AER may consider it premature to approve commingling, unless there are compelling reasons to do so.

If pools are larger, not in a stage of advanced depletion, and/or have good deliverability, the AER may consider that segregated production should be maintained to allow for the collection of segregated pool data for the purpose of enhancing pool management to obtain optimum recovery of reserves.

You should only include a structural map if it is a key in determining fluid interfaces or pool delineation.

c) a tabulation of the interpreted net pay, porosity, and water saturation for each well in the pool, coal zones, and shale zones and the cutoffs applied.

If you do not supply tabulated well data for all wells in the pools/zones, you must explain why.

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12) For all types of reservoirs including coal and shale reservoirs, an interpreted and annotated log cross-section or representative well logs showing

a) stratigraphic interpretation of the zones of interest,

b) interpretation of the fluid interfaces present,

For cases involving gas pools, an annotated representative well log is sufficient. If oil pools are involved and the potential for enhanced oil recovery must be addressed, you should include the annotated cross-section.

c) completions and treatments to the wellbores, with dates,

d) cumulative production,

e) finished drilling date and KB elevation, and

f) the scale of the log readings.

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13) A tabulation of

a) the results of deliverability, flow, or production tests on **each** pool and coal and shale zone proposed for commingling in the wells of interest, together with an indication of the type of test involved (e.g., AOFP) and the date of the test, or

b) if a well is currently producing, a tabulation summarizing the current productivity of each pool and coal and shale zone in the subject well.

The AER is not prepared to consider requests to approve commingling of production from pools/zones unless those pools/zones are considered to be capable of production. This would at minimum entail flow test data showing that the individual pool/zone is capable of production. (Copies of the actual tests are not required for the application unless specifically requested.)

If a well is producing, only a summary of current productivity for each pool/zone in the well involved is required. You should not include the entire production history of the well in the application, unless the production trend is the basis for the request.

If the productivity of a pool/zone has declined significantly or is low from the outset, the case for commingled production is strengthened in that it can be argued that commingling would allow each pool/zone involved to produce economically for a longer time and thus enhance overall recovery.

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14) Initial and current sandface pressure information in accordance with *Directive 040* for each pool and coal and shale zone together with an indication of the type and date of the test or the analysis used

The AER requires current pressure information to adequately evaluate the application. If no individual-pool pressure tests have recently been conducted, current individual-pool pressures should be estimated using best engineering practices.

to estimate the pressures, and if there are pressure differences between pools and coal and shale zones proposed for commingling, evaluations of

a) the potential for cross-flow of reservoir fluids between the pools and zones, particularly when the well is shut in, and

b) why the pressure differences will not result in any adverse impacts if commingling is permitted.

Pressure differences between pools/zones raises the possibility that commingling of production may result in the cross-flow of reservoir fluids between pools. The cross-flow may contaminate a non-saline water zone or result in an adverse impact on the recovery of hydrocarbons from a pool/zone involved. For example, recovery may be adversely impacted by cross-flow of fluids by gas entrapment behind perforations, by precipitate formation resulting from incompatible reservoir fluids, or by the movement of fine particles. In addition, a water-sensitive formation may be damaged by the cross-flow of water.

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15) If the application has been filed because the reservoir pressure of a pool or zone proposed for commingling exceeds 90 per cent of the lesser of the closure or breakdown fracture pressure of one of the other pools or zones proposed for commingling,

   a) calculations to demonstrate that the reservoir pressure of a pool or interval proposed for commingling exceeds either

      - 90 per cent of the fracture closure pressure of a shallower zone that has been fracture stimulated, or
      - 90 per cent of the fracture breakdown pressure of a shallower zone that has not been fracture stimulated,

   b) confirmation that the shallow pool or zone will be segregated during periods that the well is shut in, including a wellbore schematic showing the actual or proposed completion to ensure segregation, and

   c) pressure decline analysis to demonstrate the length of production time needed for the pressure of the higher-pressured pool or zone to decline so that segregation is not required during periods the well is shut in.

Closure pressure is the pressure needed to open and/or extend a fracture resulting from previous stimulation operations. Breakdown pressure is the pressure needed to initially fracture a reservoir during stimulation operations.

Having extreme pressure differences between pools/zones proposed for commingling raises a safety issue in that wellbore control may be jeopardized if fluid from a high-pressured reservoir flows into a lower-pressured reservoir that has a well completion or wellhead equipment not designed for such high pressures. Another concern about the commingling of production from pools/zones with extreme pressure differences arises when a new well is drilled into a pool/zone that has an unusually high pressure due to cross-flow from a commingled completion; this raises a safety issue in that the party drilling nearby may not anticipate the higher pressure.

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16) Identification of the existing or proposed enhanced recovery scheme, including the approval number of any existing scheme or the application number of any proposed scheme.

17) For any oil pools involved,

a) confirmation that the oil pools have a common rate control or, alternatively, a separate application requesting a change in rate control has been submitted to the AER,

Production from oil pools with different rate controls may not be commingled.

b) if there is associated gas, confirmation that approval of concurrent production has been obtained or that a separate application requesting concurrent production approval has been submitted to the AER,

Separate applications must be submitted for commingling approval and for concurrent production and good production practice.

c) a discussion respecting whether the oil pool involved contains or has potential for an enhanced oil recovery scheme and, if so, the possible effect of approval for commingling of production on the effectiveness of such a scheme, and

Commingling of production in the wellbore might not be an optimum strategy when it may hamper the effectiveness of an enhanced recovery scheme.

d) A discussion evaluating the oil and gas reserves for each pool.

Discussion should include an estimate of the initial oil and gas volume in place, estimated recovery factors, and supporting data in determining these values.

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18) For any gas pool located in an oil sands area,

a) confirmation that there is no shut-in order for the subject well and zones arising from a gas/bitumen proceeding and that the wells and zones are not subject to any upcoming gas/bitumen proceeding,

b) a statement that the well involved would be producing in accordance with AER *Interim Directive (ID) 99-01*, and

c) a discussion indicating that the loss of individual pool data resulting from the commingling will not adversely affect

For wells drilled and/or completed in a defined oil sands strata after July 1, 1998, you must submit an application and obtain approval from the AER before any gas, other than solution gas, may be produced.

In an area where pool performance and pressure data are scarce (e.g., low drilling density, limited production), the ongoing collection of zonal data may prove crucial to future decisions on gas production and to the re-evaluation of past gas production approvals. Unless the AER is satisfied that the region of influence of the gas zones in the area is well defined, commingling may be denied.

future evaluation of the impact of gas production on the bitumen resource in the area.

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19) If an area-based approval is being requested,

a) evidence, with supporting discussion and analysis, that the application applies to specific zones in all portions of the area of application, and

Evidence would normally include a geological interpretation, along with data that show that the zones are present and productive throughout the area of application. Data from contiguous lands not owned by the applicant may be used in support of the application. The discussion and analysis may be combined with related information required in this section.

b) a discussion demonstrating that conservation goals are at least as likely to be achieved through commingling of production as through segregated operations, and

The discussion should show that the loss of individual pool or zone data resulting from the commingling will not adversely affect the ability of the operator to adequately manage pool operations in future.

3.2 Background to Good Production Practice, Gas-Oil Ratio Penalty Relief, and Special Maximum Rate Limitation

Most new oil pools in Alberta initially have rate controls applied. These restrictions are designed to ensure that oil pools in the province are not significantly depleted before the pool's optimum depletion strategy can be determined. This helps to ensure that enhanced oil recovery (EOR) feasibility is addressed early in the pool's life, along with solution-gas conservation, concurrent production, and any equity problems among operators in the pool. The tool used by the AER to impose rate controls is the Maximum Rate Limitation (MRL) Order.

Generally, the AER will not approve accelerated production rates to improve the economics for initiating enhanced recovery or data gathering to determine and assist in optimization studies. The AER also notes that the applicant should refer to *Directive 007-1: Allowables Handbook* for details on the administration of allowables and the rules regarding retirement of overproduction.

Applications to remove oil rate controls fall into three categories:

- a request that the oil pool be removed from the MRL system (good production practice [GPP])
- a request for an amendment to the MRL Order modify or remove gas-oil ratio (GOR) penalties
- a request for an amendment to the MRL Order increase the MRL above its reserves-based value (Special MRL)

Before approving any of the above applications, the AER must be satisfied that

- the pool is operating under its optimum depletion strategy to ensure that economic oil recovery is maximized,
- gas conservation has been addressed using the decision tree and economic decision process set out in AER *Directive 060*, and
- equity issues have been resolved.

Because the issues are the same in each application, the AER often approves GPP when GOR penalty relief and/or Special MRL have been applied for. The following section outlines the content requirements for these three applications, starting with GPP. GOR penalty relief and Special MRL are treated as alternatives to GPP when unique circumstances exist that would preclude granting GPP.

3.3 Application for Good Production Practice—Primary Depletion Pools

This section deals only with GPP applications for pools under primary depletion. GPP removes a pool from restrictions imposed by the AER's monthly MRL Order and is granted under section 10.060 of the *Oil and Gas Conservation Rules*. Under GPP, the wells in a pool are not restricted by base allowable or GOR penalties. However, as the name implies, operators are expected to produce the wells in accordance with good engineering practices to optimize oil recovery. The AER may rescind GPP approval if new information or technology indicates that production under GPP may affect conservation or the rights of other owners in the pool. GPP may be granted with concurrent production restrictions on gas cap production or other conditions.

Note that for pools under primary depletion, GPP is granted to the pool, not to individual wells. For pools where EOR schemes exist, GPP is usually granted only to the ER oil scheme areas.

3.3.1 Requirements for an Application for GPP

Requirements	Comments
1) Your geological interpretation of the pool, including	
a) a net pay isopach map of the pool, including both oil and gas if there is an associated pool, b) where pool delineation or fluid interface locations are based on structural interpretation, a structure contour map of the pool and offsetting area, c) an interpreted and annotated log cross-section or representative well logs showing the i) stratigraphic interpretation of the zones of interest, ii) interpretation of the fluid interfaces present, iii) completions and treatments to the wellbores, with dates, iv) cumulative production, v) finished drilling date and kelly bushing (KB) elevation, and vi) scale of the log readings, and d) a tabulation of your interpreted net pay, porosity, and water saturation for each well in the pool, along with the cutoffs, methodology, formulas, and constants used.	For primary pools, GPP is granted to the entire oil pool. Therefore, the application must provide a geological interpretation of the entire pool, not just lands you own. If it will help to clarify your basis for pool delineation or other aspects of your geological interpretation, you should submit a log cross-section containing wells both within and outside of the pool. As a minimum, you must submit at least one representative well log from a well in the pool showing the information required in item 1(c). You must provide a clear picture of your geological interpretation, including the potential for further pool development.

2) Your evaluation of the oil and gas reserves for the pool, including

   a) an estimate of the initial oil volume and gas volume in place,

   b) an estimate of the oil and gas recovery factors,

   c) a description of the methods used in determining (a) and (b) above (e.g., material balance, volumetric analysis, model study, and a comparison of analog pools), and

   d) the supporting data used in determining (a) and (b) above and the sources of the data (e.g., pressure/volume/temperature [PVT] properties and source, pressure data and source).

The size of oil and gas cap reserves affects depletion strategy, EOR feasibility, and gas conservation economics.

The stage of depletion of the pool may influence the AER's decision and should be discussed where appropriate.

If there are sufficient pressure, production, and PVT data, you should do a material balance evaluation and compare it to the volumetric results.

Failure to provide information on the calculation methods and supporting data will delay processing of your application.

It is not necessary to provide production plots for the wells, except to illustrate a particular point or issue (e.g., decline analysis, specific well performance issues).

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3) A discussion and analysis of why waterflooding or some other form of enhanced oil recovery (EOR) is not feasible for this pool. This should include

   a) your screening criteria and supporting calculations and data,

   b) if EOR was found to be technically feasible but uneconomic, your economic evaluation and supporting data, and

EOR evaluation is a critical part of any GPP application, and processing delays will result if it is not done properly. If the AER agrees that the pool is a single-well oil pool with no potential for expansion or further drilling or is in good communication with a fully active aquifer system, EOR will not be an issue.

If EOR is considered feasible, GPP will be denied pending implementation of EOR.

c) if numerical simulation was used, a description of the model, the input data, results of history matching, cutoffs used for each case, descriptions of the cases run, and summaries and analyses of the results.

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4) Analysis, discussion, and supporting data to show that producing the pool under GPP is the optimum depletion strategy for the pool. If there is gas-cap gas production, you need to supplement this with the information required for a CCP application and identify further conditions needed to approve CCP (e.g., gas rate limit, maximum GOR).

This should build on the analyses in items 3 and 4 above. Having eliminated EOR, you must satisfy the AER that producing wells at unrestricted rates will not reduce primary recovery.

If the MRL and GOR penalties do not restrict production in the pool now or in the future, you should include this in your discussion.

At this point you may wish to request a reduced pressure test frequency in the pool if you can show that a lesser frequency is appropriate.

Failure to adequately address CCP will delay processing. Please refer to the CCP application requirement in unit 2, section 2.4.

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5) A discussion of the status of gas conservation from wells in the pool, including wells owned or operated by others. This discussion should

a) confirm that full gas conservation from all wells is occurring and will continue, or

b) outline the schedule for implementation of full gas conservation, or

c) justify why you are not proposing full gas conservation under GPP.

Your evaluation of gas conservation should use the decision tree and economic decision process set out in AER *Directive 060*, sections 2.3 and 2.4.

Under full gas conservation, only nonroutine flaring can occur. *Directive 060*, section 2.6, defines nonroutine flaring at conserving facilities and specifies operational requirements to minimize this flaring.

Failure to address gas conservation in accordance with *Directive 060* will result in processing delays and deficiency requests.

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6) Individual legible maps showing

   a) the lessees in and adjoining the applied-for pool, and

   b) the lessors in and adjoining the applied-for pool.

To ensure clarity, you should construct your own map, rather than submit a photocopy from part of a commercial land map you purchased. Confusion about ownership in the area will delay processing.

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7) If there is mixed ownership in the pool,

   a) state that you are applying on behalf of all well licensees in the pool, or

You are encouraged to apply on behalf of all well licensees in the pool. If not, the AER's application process must ensure that parties having a bona fide interest in the application are provided an opportunity to intervene. For more information, refer to the *Oil and Gas Conservation Act* and the corresponding *Responsible Energy Development Act*.

   b) identify the well licensees not represented, explain why they are not represented, and evaluate the impact that GPP approval will have on the rights of these owners.

Your evaluation of the impact on parties not represented should include supporting data; otherwise processing will be delayed.

3.4 Application for Gas-Oil Ratio Penalty Relief

GOR penalties are applied to an oil well's MRL when the producing GOR exceeds the base GOR. The penalty factor is calculated by taking the ratio of the base GOR to the producing GOR. The MRL is then multiplied by this penalty factor to determine the adjusted MRL (the permitted production rate). GOR penalty relief is applied for under section 10.060 of the *Oil and Gas Conservation Rules*.

GOR penalty relief applications face the same issues as GPP. For this reason, when processing a GOR penalty relief application, the AER will often grant GPP, with full gas conservation as a condition. GOR penalty relief is approved through the application of a net GOR penalty factor, which reduces the GOR penalty by subtracting out any fuel gas or gas delivered to an approved gas gathering system.

GOR penalty relief is not automatic when gas is conserved. When GORs rise significantly above the solution GOR of the oil, this indicates that pressure depletion and/or gas cap coning is occurring, neither of which is desirable for optimum oil recovery. These issues must be addressed before an application can be approved, despite ongoing gas conservation.

3.4.1 Using the O-33 Form

To apply for GOR penalty relief, operators often use the O-33 form, which was introduced in 1989 as part of *Informational Letter (IL) 89-14*. The O-33 form is specifically targeted at small (one or two wells), low-quality pools (rates below minimum allowable initial high-water cuts). *Directive 065* supersedes the requirements set out in *IL 89-14*, but the AER will continue to accept the O-33 form for small, low-quality oil pools if the conservation and equity issues are not complex. See appendix C for a copy of the O-33 form.

3.4.2 Requirements for an Application for GOR Penalty Relief

For GOR penalty relief application requirements please use the GPP application requirements and comments (section 3.3.1). Note that CCP must also be applied for (see section 2.4) if the high GORs are a result of production from a gas cap. You should also state in your application why you are applying for GOR penalty relief rather than GPP.

3.5 Application for Special Maximum Rate Limitation (MRL)

A Special MRL is an MRL approved by the AER that is greater than the reserves-based MRL. Special MRLs can be applied to entire pools or individual wells. Relatively few Special MRL applications are received or approved each year because, like GOR penalty relief, Special MRL applications have the same issues involved as GPP. For this reason, when processing a Special MRL application, the AER will often grant GPP. A Special MRL is applied for under section 10.060 of the *Oil and Gas Conservation Rules*.

3.5.1 Requirements for an Application for a Special MRL

For Special MRL application requirements please use the GPP application requirements and comments (section 3.3.1). You should also state in your application why you are applying for Special MRL rather than GPP.

3.6 Application to Amend or Rescind a Gas Allowable Order

3.6.1 Background

There are essentially three situations when the AER may issue a gas allowable (GA) order for the purpose of setting the maximum allowed gas production rate for a gas well or wells in a pool:

- if the ultimate recovery of gas may be adversely affected by unrestricted production rates (section 10.300(1) of the *Oil and Gas Conservation Rules* [*OGCR*]),
- if a gas well is completed outside of its prescribed target area and it is necessary to apply an off-target penalty to the well's base allowable for equity reasons (section 4.070(1) of the *OGCR*, AER *Interim Directives [IDs] 94-02* and *94-05*), and
- if the AER has deemed a fractional tract of land to be a drilling spacing unit and there is a need to apply an area-ratio production penalty or off-target penalty for equity reasons (section 4.050 of the *OGCR*).

Section 10.095 of the *OGCR* designates that the base allowable for a gas well shall be its maximum daily allowable (Q_{max}). The calculation of Q_{max} is explained in section 10.300(1)(c) of the *OGCR* and in AER *Informational Letter (IL) 85-10*. In all instances above, the penalties are applied against the well's Q_{max} and an annual allowable (based on this Q_{max} and the number of days in the year) is assigned.

3.6.2 When to Make This Application

When a well is subject to an AER gas allowable (GA) order and the well's licensee believes that circumstances warrant the allowable being rescinded or amended, an application can be made to change the allowable in accordance with section 10.300(4) of the *OGCR*. There are a number of reasons for a change to a gas well's allowable, including

- equity (e.g., there is no longer an offsetting productive well),
- conservation (e.g., there is no longer a reason to restrict the rate for conservation reasons),

- pool delineation (e.g., data support a new pool interpretation that does not warrant the application of a gas allowable to the well), or
- administrative (e.g., the well can no longer meet the allowable).

The original reason for the initial assignment of the allowable will dictate the basis for any requested change, and the application must address what has changed since the original allowable was assigned to the well to justify the application. The majority of gas allowables are assigned for equity purposes, resulting in equity matters being of primary consideration in most applications to amend or rescind a GA order.

3.6.3 How the AER Processes the Application

Upon receipt, the AER reviews the application for completeness according to the following requirements. Particular attention is paid to equity considerations. If pool delineation is an issue (i.e., the AER's current pool delineation is different from the applicant's and this difference is material to the assignment of the allowable), the AER will undertake geologic and engineering reviews of the pool delineation. In all cases, contact with offset licensees will be checked to ensure that proper notification is conducted. In particular, contact with any offset licensee that caused the assignment of the original allowable will be ensured. Once the technical, administrative, and equity aspects of the application have been reviewed, a decision will be issued or a hearing will be set to consider the matter.

3.6.4 Requirements for an Application to Amend or Rescind a Gas Allowable Order

An application under section 10.300(4) of the *OGCR* to either amend or rescind the maximum daily allowable prescribed to a gas well must include the following. The information required can vary, as noted in the Comments column below, depending on the reason for the original allowable being assigned.

Administration

Requirements	Comments
1) A statement that the application is made in accordance with section 10.300(4) of the *OGCR*.	This is a legal requirement.
2) The unique well identifier of the well for which you are requesting a change in the allowable.	
3) A summary of the basis of the application.	Why do you believe that the maximum daily allowable should be changed? You may need to address conservation and/or equity, depending on the reason for the original assessment of the allowable to the well.

Conservation

Requirements	Comments
1) A map showing the net pay isopachs and zero edge of the pool.	The AER requires this information to confirm the pool extent. The pool's net pay and zero edge must reflect your actual geological interpretation of the pool.
2) A map showing the status of each well completed in the pool.	
3) A map showing the structure of the top and base of porosity and the initial and present fluid interfaces.	This information is required only when the allowable was originally assigned for conservation reasons, and then only when structure is pertinent to the application.

4) A map showing isobars of the pool.	This is generally only required if pool delineation is an issue.
5) Tabulations of a) reservoir parameters, b) the estimated initial in-place volumes of gas and other hydrocarbons in the pool, c) for the pool, the current rate of production of gas, other hydrocarbons, and water and an estimate of the probable pool production rates under the proposed operating conditions, and d) for each well, the current productive capacity, the current average production rate, and the production rate anticipated under the proposed operating conditions.	The information referred to in 5(c) and (d) is generally required for the entire pool only when allowables have been set for an entire pool for conservation reasons or when pool delineation is an issue. When only a portion of the pool is affected by the subject allowable, data on just the subject well and immediately offsetting wells are usually sufficient.
6) Discussions of a) pertinent characteristics or conditions that exist within the pool, including geological factors, reservoir characteristic, general or local fluid interface movements, pressure gradients, areal drainage, or production conditions, b) the predicted future recovery of gas and other hydrocarbons from the pool under existing production rate limitations and under the proposed operating conditions, particularly the uniformity of drainage within the pool, and c) the conservation and administrative benefits that would accrue from granting the application.	Information referred to in 6(a) and (b) is required only when the allowable was originally assigned for conservation reasons.

7) An interpreted and annotated log cross-section or representative well logs showing

   a) stratigraphic interpretation of the zones of interest,

   b) interpretation of the fluid interfaces present (current and original, if applicable),

   c) completions and treatments to the wellbores, with dates,

   d) cumulative production,

   e) finished drilling date and kelly bushing (KB) elevation,

   f) the scale of the log readings, and

   g) a tabulation of your interpreted net pay, porosity, and water saturation for each well in the pool, along with the cutoffs, methodology, formulas, and constants used.

This information is required only when the allowable was originally assigned for conservation reasons or when pool delineation is an issue. You may present this cross-section in a number of ways (as one representative well log, several well logs, or a detailed cross-section of the entire pool) depending on the complexity and heterogeneity of the pool.

If you do not supply tabulated well data for all wells in the pool, you must explain why the data are not included (e.g., the allowable affects only a portion of the entire pool). As a minimum, you must provide the data for the subject well and all immediately offsetting wells.

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8) A discussion of

   a) well completion and recompletion details and assessment of the prospects for control of water production in the future,

   b) operating problems,

   c) the effect of increased production on liquid coning, terminal fluid interface position, and interpool interference,

The information for 8(a) to (e) is required only when the allowable originally was assigned for conservation reasons.

Requirements	Comments
d) the effect on the rates of production of any oil, condensate, or pentanes plus that may be present in the pool if the application is granted,	
e) appropriate economic analyses, and	
f) pertinent reservoir studies.	The information for 8(f) is required only when the allowable was originally assigned for conservation reasons or when pool delineation is an issue.

Notification—Equity

The AER requires the information described below to consider any potential direct and adverse effect to a party and whether equity issues may exist. You are encouraged to carry out the notification described here. The AER reserves the right to advertise any application for its own purposes.

Requirements	Comments
1) A map showing a) the zero edge of the pool, b) the status of each well completed in the pool, and	This information generally is required only when the allowable originally was assigned for conservation reasons or when pool delineation is an issue.
c) the licensees in the pool and for 1600 m surrounding the pool that contains the well for which a change to allowable is requested.	Generally, only when allowables have been set for an entire pool for conservation reasons is the full level of notification referred to in 1(c) required. The 1600 m buffer around the pool is included to ensure that no offset licensees have a different interpretation of the pool. In most cases, affected parties are those considered by the AER to have a productive well in the same geological pool in a drilling spacing unit (DSU) immediately offsetting the subject well.

	If the allowable was established because the subject well is off target, generally only wells in the same geological pool that the subject well is off target towards are considered to be affected, in accordance with AER *Interim Directive (ID) 94-02*. If the allowable was originally assigned for equity reasons, the offset licensees that requested that the allowable be set must be contacted.
2) A list of the parties notified regarding the proposed allowable change, a copy of the dated notification, and any comments received from the notified parties.	
3) A discussion of the effect that granting the application would have on the interests of other owners in the same pool.	

Unit 4 Disposal/Storage

4.1 Application for Disposal (Classes I–IV)

4.1.1 Background

Disposal refers to the injection of fluids into underground formations for purposes other than enhanced recovery or gas storage. The injection of heat-depleted fluids into underground formations, as envisaged in *Directive 089: Geothermal Resource Development*, and into underground formations, as envisioned in *Directive 090: Brine-Hosted Mineral Development*, is to be addressed in the same manner as disposal fluids defined in *Directive 051*. Under section 39(1)(c) of the *Oil and Gas Conservation Act*, section 16 of the *Geothermal Resource Development Rules*, and section 6(1)(a) of the *Mineral Resource Development Act*, AER approval of a scheme is required for the gathering, storage, and disposal of water produced in conjunction with oil and gas, the development of minerals resources, brine-hosted mineral recovery, and injection of water from geothermal resource development projects. Section 39(1)(d) of the *Oil and Gas Conservation Act*, section 16(1) of the *Geothermal Resource Development Rules*, and section 6(1)(b) of the *Mineral Resource Development Act* require AER approval of a scheme for the storage or disposal of any other fluid or substance to an underground formation through a well. The disposal scheme approval holder must be the licensee of all the wells on the approval. CO_2 sequestration projects are Class III disposal schemes and must meet the additional requirements in sections 4.1.6 and 4.1.7 as well as the general requirements for disposal schemes.

The AER classifies disposal wells based on the type of injection fluid. This classification system is outlined in *Directive 051*.

Directive 051 applications for the disposal of all fluid types may be submitted at any time before or after the submission of the *Directive 065* application.

Submit *Directive 065* and *Directive 051* applications using the Digital Data Submission (DDS) system, available through the Systems & Tools portal on the AER website, www.aer.ca.

All disposal wells must meet the *Directive 051* requirements prior to the commencement of fluid injection.

4.1.2 When to Make This Application

If the disposal of a fluid is required and you are certain that disposal at the proposed location will not cause an environmental or safety hazard and will not result in incremental hydrocarbon recovery, then you should make an application for disposal to the AER.

The AER will permit, without application, a maximum cumulative water injection of 500 m^3 in order to acquire the information required under *Directive 051* and to determine the maximum wellhead injection pressure (MWHIP).

Wells proposed for disposal, gas storage, and sequestration schemes do not necessarily have to be drilled before submitting a scheme approval. If the injection well has not yet been drilled, an optional two-step pre-drill application process is available for all disposal, gas storage, and sequestration schemes. This process allows operators to receive a conditional approval before drilling disposal wells and constructing the associated surface facilities. Further details regarding the pre-drill process are outlined in the application process guidelines on the AER's website.

If the pre-drill application process is not used, the regular disposal or sequestration application process must be used, which requires that the proposed disposal or sequestration wells be drilled before application. Notifications, as required in tables 1–3, are normally valid for two years, and renotification may be required if the ownership structures and potentially affected parties change in the interim.

4.1.3 Application Requirements for a Disposal Scheme

General

Requirements	Comments
1) A description of the proposed disposal scheme, including a) unique well identifiers, b) disposal zone with zone top and base, c) disposal perforations, d) disposal fluid class, e) anticipated daily disposal volumes, and f) depth of the production packer.	You should identify the class of the disposal fluid according to the system outlined in *Directive 051*.
2) A statement on why the proposed well is suitable for disposal.	You should discuss why the well is suitable for disposal and include information on how usable groundwater is protected. Base of groundwater protection (BGWP) elevations are available for locations across Alberta by using the Base of Groundwater Protection Query Tool on the AER's Systems & Tools portal.
3) A statement on why the proposed disposal is required.	
4) An indication of whether you have applied for or obtained approval for related surface facilities.	Surface facility applications must be made in accordance with *Directive 056* or *Directive 058*.
5) An indication of whether you have applied for or obtained approval for the related	

geothermal well in accordance with *Directive 089*.

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6) An indication of whether you have applied for or obtained approval for the related brine-hosted mineral well in accordance with *Directive 090*.

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7) Identification of the following:

   a) fluid type currently in the disposal interval (i.e., water, gas, or oil),

   b) confinement strata,

   c) porosity and permeability of the disposal zone, and

   d) the distance between the proposed disposal wells and any hydrocarbon pool or accumulation.

Conservation

If disposal is to occur into a hydrocarbon pool or an associated aquifer, it must be evident that it will not have a detrimental effect on the ultimate hydrocarbon recovery from the pool.

If the proposed disposal well is more than 1.6 km from any potentially affected hydrocarbon pool or accumulation, you may omit requirements relating to conservation.

Requirements	**Comments**
1) A discussion on hydrocarbon pools or accumulations within 1.6 km of the disposal well.	

2) If disposal is into a hydrocarbon zone or associated aquifer:

   a) A discussion on the stage of depletion of the recipient hydrocarbon zone.

   b) A statement on whether the hydrocarbon zone contains an oil-water (o/w) or gas-water (g/w) contact. Provide the depths of all contacts in relation to the proposed injection interval.

   c) An explanation of why the proposed disposal would not be detrimental to ultimate hydrocarbon recovery.

      If incremental recovery is anticipated as a result of the proposed injection, consider applying for enhanced recovery rather than disposal.

   d) A net pay isopach map of the zone, including both oil and gas if there is an associated gas pool.

   e) A discussion on the proposed maximum operating pressure for disposal into the receiving hydrocarbon zone or the associated aquifer.

      The AER believes that disposal wells that are injecting into hydrocarbon zones without volume restrictions could ultimately result in the zone's pressure exceeding the formation's initial pressure. As a preventive measure, a maximum operating pressure will be applied to all disposals into hydrocarbon zones or associated aquifers based upon the initial pressure of the zone. Approvals may be conditioned on the acquisition of annual shut-in reservoir pressure tests as per *Directive 040*. Certain wells and pools may be placed on the annual pressure survey schedule.

Hydraulic Isolation

Disposal approvals specify the disposal zone and limit injection to that zone only. Migration of disposal fluids to other zones is highly undesirable. Therefore, a suite of logs, in addition to the following information requirements, is needed for all injection wells in the province to confirm that there is no flow of injected fluid behind the casings, as per *Directive 051*. For additional details on the logging requirements, see *Directive 051*.

Requirements	Comments
1) For disposal wells injecting hydrogen sulphide (H_2S), Class I and Class III fluids, all completion logging, testing requirements, and associated discussion required by *Directive 051*.	
2) In order to prove hydraulic isolation for Class II and Class IV disposal, the wellbore integrity logs must be submitted to demonstrate hydraulic isolation of the disposal zones in accordance with *Directive 051*.	
3) If three months is not sufficient time to meet *Directive 051* requirements, request an extension, providing the following information: a) the proposed submission date, and b) the reasons for needing the submission date extension.	Disposal well approvals issued in advance of *Directive 051* requirements being met will contain a clause requiring that the *Directive 051* information be submitted within three months of the approval's issue date.
4) When submitting *Directive 051* information after the approval has been issued, you should provide the field and pool name, the disposal scheme approval number, and the well locations.	If the *Directive 051* requirements are not submitted within the three months or other approved timeframe, AER staff will rescind the approval or portion pertaining to the subject wells. For more information on submission requirements and the disposal approval process, see AER *General Bulletin (GB) 2000-8*.
5) Provide the following information for either (1) all the wells in the pool if disposal is into a depleted hydrocarbon pool or (2) all	There must be hydraulic isolation between the disposal fluid and any other wellbores drilled into or through the disposal zone.

the wells within the disposal well section and adjoining sections if disposal is into an aquifer system:

a) well location,

b) status of well,

c) completion intervals, and

d) all casing information.

Containment

Requirements	Comments
1) A discussion of the geological setting of the proposed disposal zone, base, and caprock.	The geological discussion should include continuity, thickness, lithology, and integrity of all zones. If fracturing is evident, explain how containment can be assured. Discussion on the disposal zone should include reservoir parameters.
2) The following maps: a) structure and isopach maps of the proposed disposal zone, and b) an isopach map of the confinement strata.	Maps should be at a 1:50 000 scale with a radius of at least 1.6 km from the proposed disposal wells. The radius should take into account an extended area of influence and/or any impacts to containment or conservation.
3) An interpreted and annotated log cross section or representative well logs showing a) stratigraphic interpretation of the zones of interest and b) interpretation of the fluid interfaces present.	All log cross sections and well logs must include the header.

4) Confirmation that all wells within the area of influence have been completed or abandoned in a manner that prevents the migration of the injected fluid or substance to another formation.

Maximum Wellhead Injection Pressure

All disposal wells will be subject to a maximum wellhead injection pressure (MWHIP). Best practices for determining the MWHIP use the formation fracture pressure with a safety factor applied. The formation fracture pressure may be determined by step-rate injectivity tests, in situ stress tests, or reliable offset data. In the absence of such information, the MWHIP prescribed in appendix O, table 1, is assigned to the disposal well.

Requirements	Comments
1) A statement of the proposed MWHIP and what it is based on.	Injectivity test data will be accepted as a means to evaluate the formation fracture or parting pressure, or to confirm injectivity without formation fracture. See appendix O for test procedures.
2) If requesting an MWHIP other than that prescribed in appendix O, table 1: a) Technical justification of the proposed MWHIP, including the complete test data and all analyses. b) A discussion on the appropriate safety factor to ensure fluid containment.	Justify all analogous sources used. Wellhead injection pressure must be less than or equal to the MWHIP at all times. Data from fracture stimulations operations will not be accepted. The AER generally applies a safety factor of 10 per cent unless an alternative is adequately justified. The AER may request tests performed on the caprock to support a requested injection pressure. Licensees are responsible for providing historical wellhead injection pressure data to the AER for an audit.

Notification, Equity, and Safety

Requirements	Comments
1) Evidence of your right or authorization to dispose into the proposed zone. (For CO_2 sequestration schemes, see section 4.1.6.)	If the application is for a new acid gas scheme or an amendment that seeks to increase the cumulative fluid disposal volume with additional captured CO_2 volumes, tenure must be granted by Alberta Energy and Minerals. If the increase is due to additional gas processing, then the existing authorization is sufficient. In all other situations, the acceptable authorization depends on the land type: • unleased Crown land – a valid Crown authorization • Crown land leased by other than the applicant – a letter of consent from the leaseholder or a valid Crown authorization where the applicant obtained the authorization before the lease was issued • Freehold lease land – consent from the Freehold mineral holder
2) Provide a) a map showing the boundaries of the disposal pool or the area within the disposal section and the offset section up to a 1.6 km radius with the requisite parties listed below displayed, and b) a statement as to whether the parties shown on the map referred to in 2(a) have been notified about the application and, if so, include any statements of concerns received.	In addition to meeting the minimum notification requirements, you are expected to notify other parties that may be affected by your application. If a risk to an abandoned well is identified by a licensee, and the well was abandoned in accordance with the applicable standards of *Directive 020*, then the applicant and the well licensee must come to an agreement on what needs to be done to bring the well to current abandonment standards. If, however, it is determined that the risk may be from a failure to meet the applicable requirements of *Directive 020*, the well licensee must notify the AER.

Requirements	Comments
Notification requirements for disposal scheme applicants are outlined in the section “Resources Applications Notification Guidelines.”	
3) All sour fluid injection operations must meet the requirements of *Directive 071: Emergency Preparedness and Response.*	
4) For Class I wells, a statement as to whether the landowners/occupants within a 0.5 km radius of the proposed disposal well have been notified about the application and, if so, include any statements of concerns received.	

4.1.4 Additional Requirements for Class I Disposal

Containment

Requirements	**Comments**
1) A discussion on the maximum expected area of influence surrounding the proposed well over the life of the scheme, including any pressure gradients that exist as a result of past or current production or injection operations.	The maximum area of influence may be estimated with the information that the applicant has available to it.
2) An area review to ensure fluid containment. Offsetting wells must be investigated for hydraulic isolation of the disposal zone within the maximum expected area of influence surrounding the proposed well or a 1.6 km radius, whichever is greatest.	Hydraulic isolation of the disposal zone is required and will be considered satisfactory if logging or cementing records show that the subject interval is cemented or isolated. For cement integrity, casing inspection, and hydraulic isolation log requirements, refer to *Directive 051*. For abandonment requirements, refer to *Directive 020: Well Abandonment*.

3) In the case of slurry fracture injection of sand, details of the surface elevation monitoring that will be done within 800 m of the proposed disposal well to monitor the impact of slurry fracture injection of sand above the formation fracture pressure.

4.1.5 Additional Requirements for Class III Disposal

In addition to the detailed requirements in the following table, a Class III disposal scheme application must include a site-specific risk assessment that will allow for thorough risk management throughout the life of the scheme approval. The assessment should include potential hazards, including geological containment, groundwater protection, offset wellbores, and induced seismicity.

If the risk assessment is medium to high, or if the projected fluid plume extent at the end of the disposal project exceeds 1.6 km around the disposal interval, then the application must also include a monitoring program that includes the baseline conditions.

The risk assessment includes the identification of safety-critical preventive and mitigative controls (such as safety-critical equipment and safety critical human actions, as defined in *CSA Z767 Process Safety Management*), and monitoring their effectiveness throughout the life of a scheme. The level of detail in a risk assessment should be proportionate to the risk and appropriate to the nature of the hazard. See the latest edition of the following standards for guidance on risk assessment: *CSA Z767 Process Safety Management* and *CSA IEC 31010 Risk management – Risk assessment techniques*.

Containment

Requirements	**Comments**
1) A demonstration of geological containment of the injected fluid and the following information in the projected area of the fluid plume or 1.6 km around the disposal well, whichever is greater: a) a geological discussion on the upper and lower confining intervals (lithology, continuity, thickness, integrity, and extent)	It is necessary to determine that there will be containment of the disposal fluid within a defined area and geologic horizon to ensure that there is no migration to hydrocarbon-bearing zones or groundwater. To address this issue, you must provide a suite of geological evidence.

b) isopach maps of the upper and lower confining interval and, if applicable, the lower confining interval

c) an interpreted and annotated cross-section demonstrating the continuity and extent of the confining intervals

d) maps showing known faulting that could compromise containment, with a supporting discussion

e) any interpreted seismic data that provides further information regarding containment assurance

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2) If a subsurface risk to the geological containment of the disposal formation is known, interpreted, or presumed by the applicant, then the application must also identify above-zone monitoring intervals and proposed monitoring well locations. The intervals and proposed well locations may be subject to the following requirements:

- pressure monitoring
- annual carbon isotope sampling of producing fluids
- bi-annual gas sampling for chemical compositional analysis

The AER may require changes to proposed monitoring well locations, or additional monitoring wells, if, in its opinion, circumstances so warrant

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3) A groundwater monitoring program is required if the risk assessment shows a risk to the groundwater. The program must

a) ensure protection of nonsaline groundwater,

b) establish baseline data for nonsaline aquifers,

c) demonstrate that the scheme will not degrade existing water quality,

d) summarize planned measures to mitigate effects and any anticipated residual effects, and

e) monitor industry and domestic wells, where appropriate.

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4) A discussion of the maximum expected area of influence, including the estimation method, surrounding the proposed well over the life of the scheme, including any pressure gradients that exist as a result of past or current production or injection operations.

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5) An area review to ensure fluid containment. Offsetting wells must be investigated for hydraulic isolation of the disposal zone within the maximum expected area of influence surrounding the proposed well or a 1.6 km radius, whichever is greatest.

Hydraulic isolation of the disposal zone is required and will be considered satisfactory if logging or cementing records show that the subject interval is cemented or isolated.
For cement integrity, casing inspection, and hydraulic isolation log requirements, refer to *Directive 051*. For abandonment requirements, refer to *Directive 020: Well Abandonment*.

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6) A surface casing vent flow (SCVF) / gas migration (GM) plan that satisfies *Directive 087: Well Integrity Management* requirements for wellbore locations within the area of influence of the acid gas plume.	*Directive 087* section 3.1.1(h) defines a serious SCVF as one that constitutes a fire, public safety, or environmental hazard. Until the source depth or formation origin is determined as outlined in *Directive 087* section 3.4.1, there is a risk that the surface SCVF could be related to ongoing downhole operations.
7) A wellbore risk assessment that includes the following: a) A review of existing wells within the projected area of gas plume to assess for and manage risks over the life of the disposal approval. The review must justify any wells that will not be upgraded to the level A abandonment standards as per *Directive 020* and timelines for abandonment activities. b) A review of offsetting wells for fluid containment to ensure hydraulic isolation of the acid gas disposal formation within 1.6 km radius surrounding the proposed disposal well or the maximum expected fluid plume, whichever is greater. c) A map of the wellbore locations that are likely to present a crossflow risk to the proposed disposal well.	
8) Records of risk assessments and all iterative updates must be retained for the life of the scheme and provided to the AER upon request.	

Fluid Properties

Requirements	Comments
1) Analysis of the native reservoir fluids.	The impact of the disposal fluid on the reservoir rock matrix, native fluid, and the pressure variations subjected to the disposal zone requires that you address phase behaviour, pressure, and migration issues.
2) Gas properties, including a) composition, b) viscosity, density, gas injection formation volume factor, and compressibility factors, and c) phase behaviour through the range of pressures and temperatures to which the injected fluid will be subjected.	
3) If the geological containment risk assessment is low, migration calculation showing radius of influence, as well as a discussion if migration could occur due to displacement, gravity, fingering, etc. (not required for depleted reservoirs less than two sections in areal extent).	
4) Complete pressure history of the pool, with material balance calculations if proposed disposal zone is a depleted hydrocarbon pool.	
5) Injectivity of the reservoir, proposed daily maximum injection rate, cumulative disposal volume, and expected life of the scheme.	

Reporting

Requirements	Comments
1) Annual progress reports providing updates on scheme operation and, at a minimum, tables reporting the following: a) compositional analysis of the injected acid gas b) mole fraction of hydrogen sulphide in the injected acid gas c) mole fraction of CO_2 in the injected acid gas d) density of the injected acid gas e) volume of acid gas injected at standard conditions f) volume of acid gas injected at reservoir conditions g) wellhead injection pressure	Measurements must be reported in metric units.

4.1.6 Additional Application Requirements for CO_2 Sequestration Schemes

CO_2 sequestration schemes are often referred to as carbon capture and storage (CCS) projects. CO_2 sequestration schemes involve the permanent storage and trapping of CO_2 in approved subsurface geological formations.

In addition to the detailed requirements in section 4.1.5 and the following table, a CO_2 sequestration scheme application must do the following:

- define the storage capacity estimates, containment, and injectivity
- for sequestration into saline aquifers, develop models and execute simulations to predict the extent of the CO_2 fluid plume (the free-phase injected CO_2 in the aquifer; but see exception for small-scale and remote sequestration projects as outlined below)
- calculate the maximum injection fluid area to be used for notifications
- ascertain that the proposed scheme will perform effectively and safely
- establish a site-specific risk assessment that will allow for thorough risk management throughout the life of scheme approval and outline risk factors, threats, preventive controls, top events, hazards, mitigative controls, and consequences
- establish baseline conditions to design and implement a monitoring program
- assess the risks associated with the storage and remediation strategies in case of loss of containment
- demonstrate that, once in operation, the fluid plume will not interfere with an existing use of the underground formation

For small-scale and remote sequestration projects for which the project fluid plume size at the end of the project life does not exceed 2.5 km around the sequestration well or for which the geological containment risk assessment is low, the applicant is not required to execute or maintain a dynamic simulation model.

The expected extent of the CO_2 fluid plume is used by the AER to evaluate containment and identify high-risk offset wells. Models and simulations should be used (as applicable on a site-specific basis for sequestration into saline aquifers) to evaluate and predict the behaviour of the CO_2 sequestration zone and to inform the risk assessment. When CO_2 sequestration is proposed for depleted reservoirs, it is prudent to assume that the fluid and pressure plumes will permeate the entire reservoir.

The pressure plume is defined as the spatial footprint of the maximum connected pore volume in the sequestration zone affected by an increase in pore pressure. The pressure plume is based on the physical pressure boundaries (determined through site characterization) and the limits of the dynamic pressure anomaly (determined through modelling and simulations of the pressure elevation). The applicant should exercise reasonable judgement on the pressure contour used to define the boundary of the dynamic effect.

Section 4.1.3 conservation requirements do not apply for CO_2 sequestration if the proposed injection CO_2 well is at a distance from any potentially affected hydrocarbon pool or accumulation greater than the maximum and final extent of the CO_2 fluid plume plus 1.6 km. It must be evident that CO_2 sequestration will not impact the recovery or conservation of oil or gas or an existing use of the underground formation for the storage of oil or gas.

4.1.7 Additional Application Requirements for CO_2 Sequestration

See appendix P for the principles and objectives of a monitoring, measurement, and verification (MMV) plan.

Notification and Equity

Requirements	Comments
1) Evidence that you have the right to inject captured CO_2 for sequestration into the proposed zone. This right must be secured prior to application submission.	Proof of the right to sequester CO_2 in a formation is a valid Crown agreement or authorization to sequester CO_2.
2) For the purposes of notification, the maximum injection fluid area must be calculated for each injection well. 3) When calculating maximum injection fluid area for dense-phase CO_2 injection into saline aquifers, the estimation must presume that stratigraphic, structural, and hydrodynamic trapping will be the dominant trapping mechanisms.	The maximum injection fluid (CO_2) area to be used for notifications is the calculated cylindrical radius of influence from the injection well, which should consider the following: • injection rates, total injection period, net porosity-thickness, irreducible water saturation • injection well completion • boundaries such as reef edges • estimated displacement efficiency and CO_2 saturation • injection fluid formation volume factor Use the entire reservoir area in a depleted reservoir setting. All estimates must be technically justified.

Application Map

Requirements	Comments
4) In addition to maps required in section 4.1.3, provide maps showing a) the sequestration lease boundary and b) the calculated maximum fluid injection area per well.	The sequestration agreement boundary as issued by the Crown.

Containment

Requirements	Comments
5) A discussion of the maximum expected CO_2 fluid plume and pressure plume area surrounding the proposed wells over the life of the scheme, including any pressure gradients that exist because of past or current production or injection operations.	Area of review, area of influence, domains of review are established by the monitoring, measurement and verification (MMV) and closure plans (see appendix C of Alberta Energy's *Carbon Capture & Storage: Summary Report of the Regulatory Framework Assessment*). Well integrity will be risk assessed as part of the MMV submission, and some offset wellbores may need to be abandoned as per *Directive 020* before commencement of injection

Safety

Requirements	Comments
6) For any CO_2 sequestration scheme approvals injection wells requesting an MWHIP, a recent injectivity test that is representative of the reservoir conditions prior to the commencement of the CO_2 injection, with a) the safety factor applied at the bottomhole formation fracture pressure, and b) any analogous offset data supported with a brief geological assessment that indicates its suitability.	If the injectivity test was conducted with only wellhead measurements, the calculation of the bottomhole pressures should also account for the frictional losses. The AER may request tests be performed on the caprock to support a requested injection pressure. As part of MMV plan development, consider the following: • fracturing of the reservoir and caprock due to dynamic changes in the thermal gradient over the life of the scheme • monitoring of injectivity • geological and geomechanical modelling for the bounding formations including caprock integrity and capillary threshold pressures

Reporting

Requirements	Comments
7) The initial application submission to the AER after obtaining a valid Crown agreement or authorization to sequester CO_2 must include the MMV and closure plan.	If the MMV and closure plan requirements as described in Appendix P have not been met, then the AER may make a conditional decision on the scheme approval. The MMV and closure plans must be finalized prior to commencement of injection.
8) The scheme operator must provide a baseline MMV, including a full set of baseline measurements collected during the pre-injection evaluation period.	All MMV and closure plans should follow the principles and objectives outlined in appendix P.

9) Updates to MMV plans and closure plans, including duration and renewal of the plans, must be provided to the AER.	Renewals to MMV and closure plans are performed every three years.
10) A timeline chart with planned and issued dates and duration of all the evaluation permits and sequestration leases and the renewal periods of MMV plans and closure plans within the sequestration lease boundary.	The timeline chart with planned and issued dates and duration should cover all phases of the project from pre-injection, injection, and post-injection.
11) An annual progress report, including scheme operation, containment, and performance.	The scheme approval will outline the reporting requirements and a date by which annual reports are to be filed.
12) Monthly reports to the AER via the Petroleum Information Network (Petrinex) on the density of the injection fluid stream.	

4.1.8 Induced Seismicity Potentially Related to Disposal Wells

This section recommends and requires steps and actions to reduce the hazard of induced seismicity from fluid disposal operations. The AER uses both proactive and reactive strategies to attempt to mitigate the induced seismic hazard. This section applies to all disposal fluid classes described in *Directive 051*.

Induced seismicity refers to earthquakes that are attributed to human activities. Critically stressed faults in the subsurface may be activated by activities in the vicinity, like fluid disposal operations. A well where operations are associated with induced seismicity is referred to as a seismogenic well. Changes in pore fluid pressure and stress caused by fluid disposal operations may allow critically stressed faults to slip and generate seismicity. Much of the time, fault activation will not be perceptible at the surface; however, fault activation may escalate towards larger ground motion, potentially resulting in harmful impacts to surface structures or people in a localized area.

Induced seismicity protocols and disposal scheme conditions are intended to limit the magnitude and frequency of induced earthquakes from fluid disposal operations. Figure 4.1 is a flowchart that outlines what current and prospective holders of disposal scheme approvals must do.

If seismicity is associated with a fluid disposal operation, the AER may amend the disposal scheme approval. The AER will notify the disposal scheme approval holder if an amendment is required. The AER may also give notice of an approval amendment to any other person it considers appropriate.

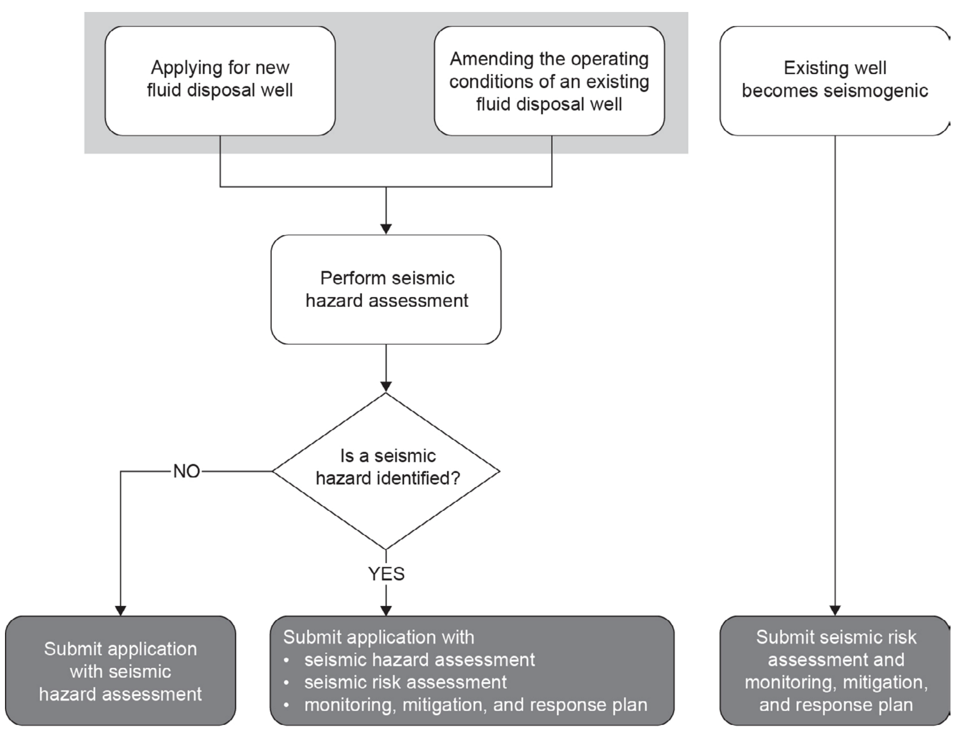

Figure 4.1 Induced seismicity process flowchart

4.1.8.1 General Requirements

The AER may, at its discretion and based on a review and analysis of data associated with observed seismic events, determine an operating disposal well to be "seismogenic." The seismogenic determination is initiated either by the operator or the AER. This may lead to changes in approval conditions that would require additional data collection, such as accurate bottomhole pressure.

1) If the AER determines the disposal well to be seismogenic, the disposal scheme approval holder must submit a seismic risk assessment and a monitoring, mitigation, and response (MMR) plan through a *Directive 065* application to amend the scheme through DDS.

2) If the AER determines the disposal well to be seismogenic, the disposal scheme approval holder must provide operational data, passive seismic monitoring information (including waveform data), and data required under the scheme approval to the AER upon request.

3) All applications for new fluid disposal wells must include an induced seismic hazard assessment. A seismic risk assessment and an MMR plan are also required if the seismic hazard assessment shows that the area is prone to induced seismic events.

4) Applications to amend the operating conditions of an existing fluid disposal well must include a seismic hazard assessment. A seismic risk assessment and MMR plan must also be included if the seismic hazard assessment shows that the area is prone to induced seismic events.

5) The approval holder must retain a copy of its MMR plan on site during disposal operations and provide the plan to the AER upon request.

6) If the disposal scheme approval holder updates its MMR plan, the revised plan must be submitted to the AER.

7) A disposal scheme approval holder with an MMR plan must follow the traffic light protocol described below should seismicity occur within ten kilometres of their disposal well (or a greater distance if directed by the AER):

    a) Green light: If the magnitude of the seismic event is less than the low threshold magnitude in the MMR plan, the disposal scheme approval holder need not take any action.

    b) Yellow light: If the magnitude of the seismic event is equal to or greater than the low threshold magnitude and less than a high threshold magnitude in the MMR plan, then the disposal scheme approval holder must immediately

        i) report the event to the Energy and Environmental Emergency 24-Hour Response Line (1-800-222-6514) and

ii) implement its MMR plan to mitigate the current hazard and reduce the magnitude and frequency of future seismic events.

c) Red light: If the magnitude of the seismic event is equal to or greater than the high threshold magnitude in the MMR plan, then the disposal scheme approval holder must immediately

i) report the event to the Energy and Environmental Emergency 24-Hour Response Line (1-800-222-6514),

ii) implement its MMR plan to mitigate the current hazard, and

iii) return the well to a safe state.

8) When a "red light" event occurs, the affected disposal scheme approval holder must receive written consent from the AER to resume any operations related to the induced seismic event (e.g., resumption if shut in, change to injection pump rate, etc.).

9) Before resuming affected operations after a "red light" event, the licensee must review and revise their MMR plan, which may involve changing the traffic light thresholds or proposing new mitigation measures. The revised plan must be validated by a qualified professional licensed to practice in Alberta, such as a member of the Association of Professional Engineers and Geoscientists, and to the satisfaction of the AER.

The AER may require changes to existing MMR plans.

If the well is not returned to a safe state, the AER may take further regulatory action.

4.1.8.2 Seismic Hazard and Risk Assessments

The goal of a seismic hazard assessment is to determine whether the proposed operation will contribute to seismicity.

10) The seismic hazard assessment must be conducted within a ten-kilometre radius around the disposal wells (or a wider radius if directed by the AER, referred to as the "assessment radius"). At a minimum, the seismic hazard assessment must use public earthquake catalogues (e.g., Alberta Geological Survey Earthquake Dashboard, Earthquakes Canada).

The seismic hazard assessment may include further evaluations, including assessment of in situ stresses, geological fault mapping using public data, operational factors, depths and major stratigraphic units, and probabilistic seismic hazard analysis for induced seismicity. The identification and assessment of an induced seismic hazard is a continuous process that the disposal scheme approval holders are expected to manage for the life of the disposal operation.

The seismic risk assessment delineates the potential impact of induced seismicity on stakeholders, population centres, private property, and "essential infrastructure" as it is defined in the *Critical Infrastructure Defence Act*. See section 4.1.5 for additional requirements on risk assessment.

4.1.8.3 Monitoring, Mitigation, and Response Plan

The monitoring, mitigation, and response (MMR) plan outlines how the disposal scheme approval holder will proactively mitigate the risk of induced seismicity for identified seismic hazards and what it will do should a seismic event occur.

11) If private property or essential infrastructure falls within the assessment radius, the applicant or the scheme approval holder must notify the landowners and essential infrastructure owners in writing for informational purposes when developing the MMR plan.

12) The MMR plan must define the thresholds of the traffic light protocol (see requirement 7) to mitigate or reduce the magnitude of induced seismic events and include a stakeholder engagement and communication strategy to support the plan's implementation.

13) The MMR plan must be authenticated by a qualified professional, licensed to practice in Alberta, such as a member of the Association of Professional Engineers and Geoscientists of Alberta, and the plan must be to the satisfaction of the AER.

14) The disposal scheme approval holder must employ a real-time seismic monitoring array within the operating area that appropriately meets the needs as outlined in the MMR for the disposal operation. The disposal scheme approval holder is responsible for the cost of deploying the seismic monitoring array. If the applicant or the scheme approval holder and the owners of affected essential infrastructure and private land (see requirement 11) cannot come to an agreement on where to deploy an accelerometer or will not allow it on their property, contact the AER. The seismic array must include at least the following:

    a) a seismometer network that can reliably detect a seismic event of local magnitude (M_L) at least equal to the "yellow light" threshold defined in the MMR within the assessment radius

    b) at least one accelerometer within the assessment radius if the seismic risk assessment identified any essential infrastructure or private property within the assessment radius that would be susceptible or sensitive to ground motion (unless agreed to by the AER)

15) Seismic monitoring data acquired from any seismometer network (including networks associated with CO_2 sequestration projects) must be submitted to

    a) the AER in near real time (see the Alberta Geological Survey's *Open File Report 2019-09* for information on naming seismometers and on the Scientific Induced Seismicity Monitoring Network [SCISMN] generally) and to

b) the Incorporated Research Institutions for Seismology.

As data is acquired over the life of the operation, we expect a disposal scheme approval holder to review its MMR plan and adjust it as necessary.

4.1.9 Disposal Scheme Amendment

A disposal scheme holds a number of disposal wells of the same class, under the same licensee, and in a specific field.

A "Disposal Scheme: Amend" application must also be submitted to the AER, through the DDS system, to amend the conditions on existing disposal wells.

The "Disposal Scheme: Amend" application may be used to request the following changes:

- revise MWHIP,
- change perforation interval (within the same formation),
- change injection packer depth,
- amend scheme-specific operating conditions,
- rescind a disposal well, or
- terminate the scheme.

An application to revise the MWHIP must also meet the requirements set out under the heading "Maximum Wellhead Injection Pressure" in section 4.1.3.

Each application should have an attachment that clearly sets out the request and the reason behind it.

4.2 Application for Underground Gas Storage

4.2.1 Background

The storage of gas into underground hydrocarbon reservoirs can be for production-motivated reasons or commercial operations. Production-motivated schemes are usually characterized by the temporary storage of gas occurring at or near the producing pools. They can allow for the more efficient use of production and processing facilities and may also be of benefit in market-related situations. Commercial gas storage schemes are designed to provide an efficient means of balancing supply with a fluctuating market demand. These schemes store third-party nonnative gas, allowing marketers to take advantage of seasonal price differences, effect custody transfers, and maintain reliability of supply. Gas from many sources may be stored at commercial facilities under fee-for-service, buy-sell, or other contractual arrangements.

The AER regulates gas storage operations to ensure that gas conservation, equity, environment, and safety issues are addressed and to maintain up-to-date estimates of provincial gas reserves and deliverability.

4.2.2 Terms of Application

An application for approval of a new scheme or amendment to an existing scheme for the underground storage of gas is made under section 39(1)(b) of the *Oil and Gas Conservation Act*. The application must meet the requirements below and include any other information requested by AER staff for evaluation purposes.

Applicants must submit the *Directive 065* application through the AER's Digital Data Submission (DDS) system.

The *Directive 051* application associated with the storage of Class III fluids must be submitted at the same time as the *Directive 065* scheme application. For all other types of fluids, the *Directive 051* application may be submitted at any time before or after the submission of the *Directive 065* application.

All storage wells must meet the *Directive 051* requirements.

4.2.3 Application Requirements for Underground Gas Storage

Conservation

The AER is concerned about any reserve losses that may occur through gas storage. Reservoir containment of the gas, gas trapping by water, excessive water production, and the dilution of produced gas by acid gas are the primary issues that need to be evaluated.

Requirements	Comments
1) Your geological interpretation of the pool, including	
a) a net pay isopach map of the pool, including both oil and gas if there is an associated pool, b) if pool delineation or fluid interface locations are based on structural interpretation, a structure contour map of the pool and offsetting area,	If the pool has a good geological history that is well defined, only one representative well log is likely required. However, if the pool is complex and has had recent development, you should provide several well logs to a detailed cross-section of the pool. If the geological interpretation submitted is not adequately done, processing delays could result.
c) an interpreted and annotated log cross-section or representative well logs showing i) stratigraphic interpretation of the zones of interest, ii) interpretation of the fluid interfaces present, and iii) the scale of the log readings, and	All log cross sections and well logs must include the header.
d) a tabulation of your interpreted net pay, porosity, and water saturation for each well in the pool, along with the cutoffs, methodology, formulas, and constants used.	

2) The following maps: a) structure and isopach maps of the proposed storage zone, and b) isopach map of the confinement strata.	Maps should be at a 1:50 000 scale with a radius of at least 1.6 km from the proposed storage wells. The radius should take into account an extended area of influence and/or any impacts to containment or conservation.
3) Maximum bottomhole injection pressure and maximum average reservoir pressure.	This information defines the upper limit to the operating pressures of the scheme.
4) Complete tabulated pressure history of the pool (date, well, type of test, stabilized pressure), along with a P/Z versus cumulative gas production plot if the pool is a nonassociated gas pool, or material balance calculations if storage is into a gas cap in communication with an oil leg.	This history indicates pressure support from the aquifer and how the reservoir may react to storage.
5) Gas analysis of the native reservoir fluid and the proposed injected gas streams.	This describes what the compositions of the gases are before they become mixed.
6) Discussion of how the storage of gas will be consistent with sound conservation practices.	
7) If at any time during storage, the average reservoir pressure will exceed the initial pool pressure (i.e., delta pressuring is being applied for), then reservoir containment of gas becomes a concern and the following are required:	
a) for the storage formation, a list of the formation fracture pressure and fracture propagation pressure, with a description of how they were determined, and	It is necessary to determine if the storage formation will be fractured and/or the extent to which the fractures may spread.

b) for the bounding formations, i) the continuity and thickness of base and caprock, ii) lithology, iii) evidence of fracturing, iv) a comment on the integrity of the base and caprock (stratigraphic, structural, or combination) and its containment features, and v) caprock threshold pressure.	
8) If there is an active aquifer system present, the trapping of gas displaced into the rising aquifer is a concern and the following are required:	
a) any measured changes in the gas/water contact, and	This will indicate where trapped gas can occur.
b) impact from the aquifer, including quantifying the amount of displaced gas that will be trapped.	This will state the impact by the aquifer and indicate whether it is a concern for storage.
9) If there are wells in the pool that have produced or are producing with high water/gas ratios (e.g., over 100 $m^3/10^6\ m^3$), loss of wells due to water coning or channelling is a concern and the following are required:	
a) production history for the wells with high water/gas ratios, and b) a discussion on how the water production is controlled.	This will show where the water problems may be occurring in the pool and how they were/are handled.

Maximum Wellhead Injection Pressure

All disposal wells will be subject to a maximum wellhead injection pressure (MWHIP). Best practices for determining the MWHIP use the formation fracture pressure with a safety factor applied. The formation fracture pressure may be determined by step-rate injectivity tests, in-situ stress tests, or reliable offset data. In the absence of such information, the MWHIP prescribed in appendix O, table 1, is assigned to the injector.

Requirements	Comments
1) A statement of the proposed MWHIP and what it is based on.	Injectivity tests will be accepted as a means of evaluating formation fracture or parting pressure, or to confirm injectivity without formation fracture. See appendix O for test procedures.
2) If requesting an MWHIP other than that prescribed in appendix O, table 1: a) Technical justification of the proposed MWHIP. Include the complete test data and all analyses. b) A discussion on the appropriate safety factor to ensure fluid containment.	Justify all analogous sources used. Wellhead injection pressure must be less than or equal to the MWHIP at all times. Data from fracture stimulations will not be accepted. The AER generally applies a safety factor of 10 per cent unless an alternative is adequately justified. The AER may request tests performed on the caprock to support a requested injection pressure. Licensees are responsible for providing wellhead pressure data to the AER during an audit.

Pool Reserves and Deliverability Information

The AER updates and publishes pool reserves data annually. For this reason it needs to understand the operations at the pool. Commercial gas storage pools are also listed in the annual reserves report, but rather than showing the remaining reserves for these pools, the storage capacity and maximum deliverability are published.

Requirements	Comments
1) An estimate of the initial gas and oil volumes in place.	This information will indicate the initial producible gas reserves.
2) An estimate of the gas and oil recovery factors.	
3) A description of the methods used in determining the initial gas/oil volumes in place and the respective recovery factors (e.g., material balance, volumetric analysis, model study, and a comparison of analog pools).	
4) The supporting data used in determining the first two points as outlined above and the sources of the data (e.g., pressure/volume/temperature [PVT] properties and source, pressure data and source).	
5) Remaining native gas in place and the cushion gas required for storage operations.	It is important to determine the remaining native gas in place before storage commences and what additional gas needs to be injected to meet the cushion gas requirements.
6) Working gas volumes.	This information will determine the storage capacity of the pool.

Requirements	Comments
7) Deliverability and injectivity of the reservoir under the range of operating conditions.	This information will indicate the production and injection capabilities of the pool.

Equity

Equity is an important issue for gas storage pools, since competitive gas production would be detrimental to storage scheme operations. Therefore, it is advisable that you own all of the mineral right leases in the pool and adjoining sections or at least have a production-sharing agreement.

Requirements	Comments
1) Provide the following: a) A map showing the boundaries of the storage pool or the area within the storage section and the offset section up to a 1.6 km radius and displaying • all well licensees, • all mineral lessees, and • all mineral lessors; and b) a statement that the above parties • within the area of the storage pool, • in all zones above and beneath the storage pool, and • in the offsetting section have been notified. Include any statements of concerns received.	
2) If you do not hold all of the mineral right leases in the pool, a brief description of the area in the pool where you do not own the mineral right leases and an explanation of why you have not purchased them.	It is important to understand the risk involved with a competing company buying mineral rights and drilling a productive well.

Hydraulic Isolation

Gas storage approvals specify the storage zone and limit injection to that zone only. Migration of fluids to other zones is highly undesirable. Therefore, a suite of logs is required for all storage wells in the province in order to confirm the absence of flow conduits for the storage fluid behind the casing. For more details on the logging requirements, see *Directive 051*. The *Directive 051* requirements must be met prior to the commencement of injection.

Environment and Safety

The AER is also responsible for environmental and safety issues when approving gas storage schemes.

Requirements	Comments
1) All injection operations that contain fluids with any H_2S must meet the requirements of *Directive 071: Emergency Preparedness and Response*.	

Monitoring Scheme Operation

Requirement	Comments
1) A discussion of the monitoring program, including the frequency and method of measuring the bottomhole and/or top-hole pressures.	This discussion will determine how the scheme will be operated to ensure that the approval conditions will not be exceeded.

Unit 5 Approval Transfers

5.1 Approval Transfer for Change of Approval Holder

5.1.1 Background

In accordance with section 15.005(1)(f) of the *Oil and Gas Conservation Rules*, the operator of a scheme approved under section 39 of the *Oil and Gas Conservation Act* is required to apply to amend the approval to show the change of holder of the approval if the scheme has been sold or divested or to show a name change that has occurred since the scheme was approved.

It is important that companies purchasing new properties in Alberta understand the terms and conditions of the approved scheme and that they update the appropriate AER documents. As operators doing business in Alberta, they are responsible to keep the appropriate documents current.

5.1.2 Requirements for an Application for a Change of Approval Holder for Schemes

The requirements in this section apply to enhanced recovery schemes, gas storage schemes, CO_2 sequestration schemes, and experimental schemes.

An application is not required to transfer the holder of a disposal scheme approval. Upon completion of a well licence transfer for a well listed in an approved disposal scheme, the AER will issue an updated approval that aligns the approval holder with the licensee of the disposal well.

Requirements	Comments
1) Transfer of approval form in appendix D.	The transferor's signature is not required for corporate name changes.
2) If the present holder no longer exists, a statement attesting to that and that the proposed new holder is the proper person/ company to assume responsibility for the scheme.	
3) For CO_2 sequestration schemes, evidence that the lessee has, from the minister, consent in writing to transfer the CO_2 sequestration agreement.	In accordance with section 118 of the *Mines and Mineral Act*.

Unit 6 Gas and Ethane Removal

6.1 Background

The removal of natural gas from the province of Alberta is governed by the *Gas Resources Preservation Act* (*GRPA*). A major reason for gas removal permits is to control the amount of gas leaving the province and thereby ensure that Albertans have an adequate supply. The AER completes an annual calculation that indicates whether or not there is gas available for inclusion in gas removal permits, taking into account a 15-year supply for the core Alberta market and obligations resulting from existing gas removal permits. *Report 87-A: Gas Supply Protection for Alberta*, available from the AER Information Product Services Section, presents the AER's policies on gas supply matters. While the forms and procedures in this document have been superseded, the report continues to provide valid information regarding gas supply protection for Alberta.

As set out in the *GRPA*, there are two types of gas removal permits:

- Short-term gas removal permits involve the removal of not more than 3 billion cubic metres (m^3) of gas over a period of not more than two years. These permits may be used for any market.
- Long-term gas removal permits involve the removal of gas in volumes greater than 3 billion m^3 of gas or permit terms longer than two years. These permits are market specific and may be used only to serve the markets described in the applications that resulted in the permits.

6.2 When to Make This Application

Under the *GRPA*, any party wishing to remove natural gas or ethane out of Alberta must apply to the AER under section 2 of the *GRPA* for a permit to authorize such removal of gas. No AER permits are required to take propanes, butanes, pentanes, other natural gas liquids, or oil out of Alberta. No permits from the AER are required to import gas into the province.

If there are corporate changes such that the party desiring to use a permit is not the permittee named in the permit, an application must be filed to amend the permit holder name in the permit.

6.3 Applications for Gas and Ethane Removal

All applications for gas and ethane removal must be filed electronically using the Electronic Application Submission (EAS) system accessed through the Digital Data Submission (DDS) screen on the AER's website, www.aer.ca. The AER will not accept applications sent in a paper format, by fax, or by email.

6.3.1 Short-Term Gas Removal Application Form

Use the on-line Short-Term Gas Removal Application form to apply for a new permit or to amend an existing permit authorizing the removal of 3 billion m^3 or less of natural gas over a period of no more than two years. Schedule 1 and the form, constitute a complete application. Submit the complete application electronically using the EAS system. The AER will validate all applications to ensure that the requirements for short-term gas removal have been met. Incomplete applications or those containing errors will be closed.

The AER's practice is to allow one short-term gas removal permit per company. When the AER receives a completed application form, it reviews the information provided to determine if it is consistent with the standard AER practices and the *GRPA*, as discussed in this section. An applicant is not required to give notification to any party or advertise its intent to apply for new short-term gas removal permit or for an amendment to an existing short-term permit. The AER does not issue any notice of these applications.

If the application is acceptable, the AER approves it by electronically issuing a gas removal permit, which can be viewed through the IAR Query for 30 days after the permit is issued. The IAR Query is accessible via Quick Links and the Applications page on the AER website www.aer.ca. After the 30-day period, issued permits may be obtained by contacting the AER's Information Product Services Section at 403-297-8311 or 1-855-297-8311 (toll free).

AER publication *ST48: Alberta Gas Removal and Related Applications*, which set out new permits issued in a given month and existing valid permits, has been discontinued. Information about when and how many short-term gas removal permits have been issued can be obtained by completing a search of applications through the IAR Query.

6.3.2 Long-Term Gas Removal Application Form

Use the Long-Term Gas Removal Application form available on the AER website by printing, filling in, scanning, and attaching it to the electronic long-term gas removal application to apply for a new permit or to amend an existing permit authorizing the removal of natural gas in volumes greater than 3 billion m^3 of gas or for permit terms longer than two years using the EAS system. Schedule 1 and the form constitute the complete application.

The AER's standard practice is to allow each company to hold one long-term gas removal permit. Some companies were able to obtain numerous long-term gas removal permits prior to the AER implementing this practice. In these cases, the AER will not allow the company to obtain any further separate long-term removal permits, but will require the company to consolidate existing permits into one permit to serve the existing markets, as well as specific new markets.

When the AER receives a completed application form, it reviews the information provided to determine if it is consistent with the standard AER practices and the *GRPA*, as discussed in this section. An applicant is not required to give notification to any party or advertise its intent to apply for a long-term gas removal permit or for an amendment to an existing long-term permit. However, as a general practice, the AER publishes notice of any long-term gas removal application in major provincial newspapers as part of processing the application, since these applications may affect the public interest. If the AER receives statements of concern to an application, the AER may hold a public hearing to consider the application.

When approval of the application is granted, the AER proceeds with the steps required to issue the new long-term gas removal permit or the amendment to a long-term gas removal permit. This includes obtaining the approval of the Lieutenant Governor in Council to issue the permit.

As in the case for a short-term gas removal permit, information about when and how many long-term gas removal permits have been issued can be obtained by completing a search of applications through the IAR Query. AER publication *ST48: Alberta Gas Removal and Related Applications* has been discontinued.

6.3.3 Short-Term Ethane Removal Application Form

Use the Short-Term Ethane Removal Application form available on the AER website by printing, filling in, scanning, and attaching it to the electronic short-term ethane removal application to apply for a new permit or to amend an existing permit authorizing the removal of ethane of not more than 3 billion m^3 of gas over a period of not more than two years using the EAS system. Resources Application - Schedule 1 and the Short-Term Ethane Removal Application form constitute the complete application.

The AER's practice is to allow one short-term ethane removal permit per company. When the AER receives a completed application form, it reviews the information provided to determine if it is consistent with the standard AER practices and the *GRPA*, as discussed in this section. An applicant is not required to give notification to any party or advertise its intent to apply for a short-term ethane removal permit or for an amendment to an existing permit. However, depending on the current supplies of ethane in the province at any time, the AER may issue notice of the ethane removal permit application in major provincial newspapers as part of processing the application. If the AER receives statements of concern to an application, the AER may hold a public hearing to consider the application.

When approval of the application is granted, the AER proceeds with the steps required to issue the ethane removal permit or the amendment to an ethane removal permit. This includes obtaining the approval of the Minister of Energy to issue the permit.

As in the case for permits to remove natural gas from Alberta, information about when and how many ethane removal permits have been issued can be obtained by completing a search of applications through the IAR Query. AER publication *ST48: Alberta Gas Removal and Related Applications* has been discontinued.

6.3.4 Long-Term Ethane Removal Application Form

No application form for a permit authorizing the removal of ethane in volumes greater than 3 billion m^3 over permit terms longer than two years has been constructed, as the AER does not anticipate any requests of this type in the near term.

6.4 Reporting Natural Gas and Ethane Removed from Alberta

Upon the commencement date of a permit for the removal of natural gas or ethane, the company holding the permit, or its agent, must file a monthly report with the AER stating the volume of gas removed and other related information. The gas removal permit data are captured electronically by the Gas Removal Data (GRD) system. All parties must file data electronically; the AER will not accept any gas removal permit data in a paper format. Questions on the reporting of gas removed from Alberta may be directed to the AER at GRDAdmin@aer.ca.

6.5 Requirements for an Application for a Short-Term Gas Removal Permit

Requirements	Comments
1) Short-Term Gas Removal Application a) Schedule 1 b) Short-Term Gas Removal Application form	Schedule 1 and the Short-Term Gas Removal Application form constitute the complete application. An applicant is not required to give notification to any party or advertise its intent to apply for a new short-term gas removal permit or for an amendment to an existing permit.

Short-Term Gas Removal Application Form

2) For a new permit, Part A a) Application submission: at least two business days before the desired start date of the permit	Complete Part A of the form if you are applying for a new permit.
b) Maximum removal volume: 3 billion m^3 (including amendments)	The volume of natural gas proposed for removal from Alberta entered in Part A is to be expressed as the total removal volume in cubic metres over the entire term of the permit. This volume is not to be expressed as a daily or annual volume.
c) Maximum term: two years	An example of a two-year term is from November 1, 2012, to October 31, 2014. A permit may be made effective on the date it is issued or at some future date. However, the AER has no legislative authority to backdate a permit.

3) For an amendment to an existing permit, Part B

Complete Part B of the form if you are applying to amend an existing permit.

a) Application submission: at least two business days before the desired start date of the permit

You may apply to amend the volume, term, and/or holder of an existing permit. Only that portion of the form pertaining to the desired amendment should be filled out; e.g., if you desire to amend only the term of a permit, leave the other portions of Part B blank.

b) Maximum removal volume: 3 billion m^3 (including amendments)

If an existing short-term gas removal permit has authorized the removal of a volume of gas less than 3 billion m^3, the permit may be amended to increase the volume up to 3 billion m^3. However, if you have an existing short-term gas removal permit authorizing the removal of 3 billion m^3 of gas and you have removed that volume of gas before the permit termination date, you cannot amend the permit to take out additional volumes of gas, as the *GRPA* limits the volume allowed for removal under a short-term permit, including amendments to the permit, to 3 billion m^3. In this scenario, you must apply for a new permit.

c) Maximum term: two years

The term of a permit may be rolled to allow a further maximum term of two years, but only if the volume of gas removed under the permit and all amendments does not exceed 3 billion m^3.

An example of a two-year term is from November 1, 2012, to October 31, 2014.

A permit may be made effective on the date it is issued or at some future date. However, the AER has no legislative authority to backdate a permit.

d) For a request to change the named permit holder: the proposed permit holder agrees to assume and perform all the obligations and duties of the existing permit holder under the permit

4) For the rescission of a permit, Part C

- Application submission: At least one business day prior to the desired termination date of the permit.

Complete Part C of the form if you are applying to rescind an existing permit.

Sometimes an existing permit should be rescinded at the same time a new permit is requested. For example, if you are requesting a new permit because you have removed the maximum volume of gas allowable of 3 billion m^3 before the termination of a permit and you want to continue removing gas from Alberta, you must apply for a new permit using Part A of the form. However, you should also ask for the rescission of the current permit, because the permit will remain active until it either reaches its termination date or is rescinded, even though you can no longer use it because of the volume limitation. As long as a permit is active, you must continue filing reports for that permit.

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5) Reporting Requirements

Complete the reporting requirements section of the form.

Report gas removed using the permit holder's or its agent's DDS account. DDS Help can be accessed on the AER website, www.aer.ca.

If the person submitting the data changes after the permit is issued, ensure that contact information is updated on the GRD submission form or within the Administrator Options area of the DDS system.

The electronic GRD submission form is accessed through the DDS system.

Requirements	Comments
a) For each permit, file an electronic monthly gas removal permit statement with the AER by midnight on the 28th day of the month following the data month. • Statements must be filed for each permit even if no gas has been removed.	The data month is the month when the gas was delivered. If the 28th is not a business day, the deadline falls on the next business day.
b) If a third party will be submitting the monthly statements, provide the submitter information.	It is important to ensure that the correct contact information for the person submitting the data has been provided.

6.6 Requirements for an Application for a Long-Term Gas Removal Permit

Requirements	**Comments**
1) Long-Term Gas Removal Application a) Schedule 1 b) Long-Term Gas Removal Application form	Schedule 1 and the Long-Term Gas Removal Application form on the AER website constitute a complete application. An applicant is not required to give notification to any party or advertise its intent to apply for a long-term gas removal permit or for an amendment to an existing permit.

Long-Term Gas Removal Application Form

2) Change of permit holder • The proposed permit holder must agree to assume and perform all the obligations and duties of the existing permit holder under the permit.	To request any change in the named permit holder, check the box in front of the words “Change of permit holder” and the box in front of the statement beginning “The proposed permit holder….”

	It is very important to check this agreement box, as this confirms that the proposed permit holder is fully prepared to take on the obligations of the previous permit holder with respect to the permit. The AER will not process a request to change the name on a permit unless this box has been checked.
3) Permits to be rescinded	Complete this portion of the form only when you want to rescind an existing permit; otherwise, leave it blank.
4) Volume of gas	
a) Total volume of gas proposed for removal	If you wish to amend an existing long-term gas removal permit to add a new market with an associated new volume, fill out the "Existing volume authorized" line to reflect the volume currently authorized for removal under the existing permit. The "Proposed volume authorized" line should reflect the existing volume authorized plus the new volume to be added. The volume of natural gas proposed for removal from Alberta is to be expressed as the total removal volume in cubic metres proposed over the entire term of the permit. This volume is not to be expressed as a daily or annual volume.
b) Gas required for fuel to transport gas from Alberta • Include a description of how fuel gas has been accounted for	Normally, such gas would be accounted for in the new volumes of gas to be removed from Alberta entered on the "Proposed volume authorized" line.

5) Term of permit

- If the proposed term is greater than 15 years, attach a discussion describing how the circumstances justify the requested term, including an indication as to whether the proposed gas removals could proceed under the 15-year permit and if not, why not.

If you wish to amend an existing long-term gas removal permit to add a new market with an associated new volume and the existing permit term covers the term of the new sale, fill out the “Existing term and commencement date” line on the form. Fill in the “Proposed term and commencement date” line only if the term of the existing permit does not accommodate the new market.

If you are applying for a new permit, leave the “Existing term and commencement date” line blank and only fill in the “Proposed term and commencement date” line.

As set out in *Report 87-A: Gas Supply Protection for Alberta*, the AER normally grants permits with a maximum term of 15 years, except in special circumstances.

A permit may be made effective on the date it is issued or at some future date. However, the AER has no legislative authority to backdate a permit.

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6) Name of proposed markets, including the location and type of end-use customers to be served under the permit

The name of the proposed market is the company to which the gas would initially be sold, as well as the names of any other companies that would acquire the gas prior to the final sale of the gas to the end-use customer. The location of the end-use customer is provinces in Canada and/or states in the United States. The type of end-use customer could be industrial, commercial, residential, and electrical generation markets.

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7) Are arrangements in place for transporting the applied-for gas from the Alberta receipt points to the intended end-use customers?	If all transportation arrangements are in place, check the Yes box, and proceed to the next item. However, if some or all of the transportation arrangements are not in place, check the No box, and explain what arrangements have been made and when it is anticipated that any new facilities required would be completed. Name the pipelines ultimately leading to the end-use market, and state what has been done to ensure that transportation arrangements will be in place. While transportation arrangements do not have to be complete in order to obtain a long-term gas removal application, steps should have been taken to acquire them.
8) Provide a summary of the pricing arrangements and how they were determined for the applied-for gas. Comment on any provisions to ensure that prices continue to reflect market conditions throughout the term of the permit.	The AER does not require specific price information; however, the method of determining the price reflects whether such arrangements are in the public interest of Albertans. The AER considers prices that adapt to constantly changing conditions and reflect a fair market value throughout the term of a permit regardless of the absolute market price to be in the public interest.
9) Discuss how the applied-for removal of gas would be in the Alberta public interest.	This should be a general discussion on provincial public interest matters.
10) Attach a table in the required format of the lands/zones that would supply the permit or amended permit, including • the legal description of all of the lands involved,	The AER's policy is that a party holding a long-term permit should have sufficient gas reserves under control to supply the entire requested volume of the permit.

- the zone or zones under your company's control for the lands in question, and
- the working interest ownership under your company's control for the lands/ zones.

Typically, a company files one corporate reserves pool (CRP) with the AER that lists the lands and zones that supply all of its AER permits. To simplify this step of the application process, an electronic file of the CRP should be set up with the AER prior to filing a long-term gas removal application. To obtain the specific format required for filing the CRP, email AER Resources Applications at ResourcesApplications@aer.ca.

After setting up a CRP with the AER, request an AER Reserves Under Control Table that lists the volume of gas reserves that the AER recognizes for the specific land, zone, and working interest information provided.

Review this table carefully. If you disagree with the gas volumes listed on the AER table associated with a specific section or note that no volumes have been listed for a section, you may request that the AER review the reserves associated with the specific section. This may be done by completing the Gas Reserves Data Sheet in appendix H.

Attach appropriate isopach maps and supporting information to the form. You should have the results of any requests made in this regard on a revised AER Reserves Under Control Table prior to filing any long- term gas removal application.

If you already have filed with the AER a CPR that is serving a permit and you are applying to amend an existing long-term permit to add a new market, the CRP must have been updated within the last calendar year.

	Attach the AER Reserves Under Control Table to the application. This table must contain up-to-date data and have been produced shortly before the filing of the long-term gas removal application. The table will serve as a public record of the location of the lands that will supply the applied-for gas removal.
11) Attach a summary of the total gas reserves volume associated with the lands serving the proposed permit, together with a list of all commitments that would be served by the reserves portfolio involved, including • the proposed permit, • other permits (specify the number of each existing permit, as well as remaining authorized commitment), • intra-Alberta commitments (such as industrial, commercial, or residential contracts or corporate warranties to other companies), and • any other commitments.	The adjusted total gas volume listed on the AER Reserves Under Control Table noted in item 10 is the volume that the AER will use in determining whether you have sufficient gas reserves under control to supply the proposed gas removal. The AER will compare the total volume noted on the table against the existing obligations you have for the gas in the CRP.
12) Reporting Requirements	Complete the reporting requirements section of the form. Report gas removed using the permit holder's or its agent's DDS account. DDS Help can be accessed on the AER website under Systems & Tools : Digital Data Submission (DDS).

Requirements	Comments
	If the person submitting the data changes after the permit is issued, ensure that contact information is updated on the GRD submission form or within the Administrator Options area of the DDS system. The electronic GRD submission form is accessed through the DDS system.
a) For each permit, file an electronic monthly gas removal permit statement with the AER by midnight on the 28th day of the month following the data month. • Statements must be filed for each permit even if no gas has been removed.	The data month is the month when the gas was delivered. If the 28th is not a business day, the deadline falls on the next business day.
b) If a third party will be submitting the monthly statements, provide the submitter information.	It is important to ensure that the correct contact information for the person submitting the data has been provided.

6.7 Requirements for an Application for a Short-Term Ethane Removal Permit

Requirements	Comments
1) Short-Term Ethane Removal Application a) Schedule 1 b) Short-Term Ethane Removal Application form	Schedule 1 and the Short-Term Ethane Removal Application form on the AER website constitute the complete application. An applicant is not required to give notification to any party or advertise its intent to apply for a short-term ethane removal permit or for an amendment to an existing permit.

Short-Term Ethane Removal Application Form

2) Change of permit holder

- The proposed permit holder must agree to assume and perform all the obligations and duties of the existing permit holder under the permit.

To request any change in the named permit holder, check the box in front of the words "Change of permit holder" and the box in front of the statement beginning "The proposed permit holder…."

It is very important to check this agreement box, as this confirms that the proposed permit holder is fully prepared to take on the obligations of the previous permit holder with respect to the permit. The AER will not process a request to change the name on a permit unless this box has been checked.

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3) Permits to be rescinded

Complete this portion of the form only when you want to rescind an existing permit; otherwise, leave it blank.

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4) Total volume of ethane proposed for removal

- Maximum volume: 3 billion m^3 (including amendments)

If you are applying for a new ethane removal permit, fill out the "Proposed volume authorized" line. The volume of ethane proposed for removal from Alberta must be expressed as the total volume in cubic metres proposed for removal from Alberta over the entire term of the permit. This volume must not be expressed as a daily or annual volume.

If an existing short-term ethane removal permit has authorized the removal of a volume of gas less than 3 billion m^3, the permit may be amended to increase the volume up to 3 billion m^3.

However, if you have an existing short-term ethane removal permit authorizing the removal of 3 billion m^3 of gas and you have removed that volume of gas before the permit termination date, you may not amend the permit to take out additional volumes of ethane; the *GRPA* limits the volume allowed for removal under a short-term permit, including amendments to the permit, to 3 billion m^3. In this scenario, you must apply for a new permit.

To request an amendment of an existing ethane removal permit, fill in both the “Existing volume authorized” and “Proposed volume authorized” lines.

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5) Term of permit

- Maximum term: two years

An example of a two-year term is from November 1, 2012, to October 31, 2014.

The term of an existing permit may be rolled by an amendment to the permit to allow a further maximum term of two years, but only if the volume of ethane removed under the permit and all amendments does not exceed 3 billion m^3. If you want to amend a permit to roll the term, fill in both the “Existing term and commencement date” and the “Proposed term and commencement date” lines.

A permit or an amendment to a permit may be made effective on the date it is issued or at some future date. However, the AER has no legislative authority to backdate a permit or an amendment to a permit.

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6) Describe proposed markets, including name, location, and type of end-use customer to be served under the permit	The name of the proposed market is the company to which the ethane would initially be sold, as well as the names of any other companies that would acquire the ethane prior to its final sale to the end-use customer. The location of the end-use customer is provinces in Canada and/or states in the United States.
7) Are transportation arrangements in place for transporting the applied-for gas from the Alberta receipt points to the intended end-use customer?	If all transportation arrangements are in place, check the Yes box, and proceed to the next item on the form. However, if some or all of the transportation arrangements are not in place, check the No box, and explain what arrangements you have made and when you anticipate that any new facilities required would be completed. Name the pipelines ultimately leading to the end-use market, and state what has been done to ensure that transportation arrangements will be in place. While transportation arrangements do not have to be complete in order to obtain a long-term gas removal application, steps should have been taken to acquire them.
8) List the name and location (Legal Subdivision-Section-Township-Range, Meridian) of the facilities from which the ethane will be obtained	This includes gas processing and straddle plants.
9) Reporting Requirements	Complete the reporting requirements section of the form. Report gas removed using the permit holder's or its agent's DDS account.

DDS Help can be accessed on the AER website, www.aer.ca, under Systems & Tools : Digital Data Submission (DDS).

If the person submitting the data changes after the permit is issued, ensure that contact information is updated on the GRD submission form or within the Administrator Options area of the DDS system.

The electronic GRD submission form is accessed through the DDS system.

a) For each permit, file an electronic monthly gas removal permit statement with the AER by midnight on the 28th day of the month following the data month.

- Statements must be filed for each permit even if no gas has been removed.

The data month is the month when the gas was delivered. If the 28th is not a business day, the deadline falls on the next business day.

b) If a third party will be submitting the monthly statements, provide the submitter information.

It is important to ensure that the correct contact information for the person submitting the data has been provided. Questions on reporting may be directed to the AER at GRDAdmin@aer.ca.

Unit 7 Application for Special Well Spacing

7.1 Introduction

Well spacing defines the number of subsurface drainage locations necessary to maximize oil or gas recovery from a specific pool or formation and the target area for these locations.

In accordance with section 16(1) of the *Oil and Gas Conservation Act* (*OGCA*) and section 5.190(3) of the *Oil and Gas Conservation Rules* (*OGCR*), a working interest participant with the right to produce may apply for special well spacing or change in target area with more flexibility for well placement in a drilling spacing unit (DSU).

Well spacing applications that do not clearly meet one of the above criteria to establish special well spacing will be closed. All applications for special well spacing must be made in accordance with *Directive 065* and must be supported by proper engineering arguments and analysis and by associated production, geological, and other engineering data.

Well spacing applications approved by the AER are displayed on the Well Spacing Map. The disposition documents for all spacing applications can be viewed for 30 days after they have been issued using the Integrated Application Registry (IAR) Query. Both the Well Spacing Map and the IAR Query can be accessed through Quick Links or the DDS system on the AER website, www.aer.ca.

7.2 Background

7.2.1 Standard Drilling Spacing Units, Target Areas, and Well Densities

The AER has authority under the OGCA to designate drilling spacing units (DSUs) and target areas and to make or amend rules pertaining to them.

As described in Part 4 of the *Oil and Gas Conservation Rules* (*OGCR*), the standard DSU is one section for a gas well and one quarter section for an oil well. Standard target area orientation—consistent throughout the province—is the central part of the DSU, except in gas DSUs in the area identified in Schedule 13A of the *OGCR* and shown in Figure 7.1. Target areas for standard oil and gas DSUs are as follows:

- For a gas well producing from the area shown in Schedule 13A, the target area is at least 150 m from the south and west boundaries of the section.
- For a gas well producing from areas not included in Schedule 13A, the target area is at least 150 m from all boundaries of the section.
- For an oil well producing from all areas of the province, the target area is at least 100 m from all boundaries of the quarter section.

Note that a well originally drilled on target in a DSU will always be considered on target regardless of any subsequent spacing approvals. However, the recompletion of a formation in a well that is not within its target area would be deemed off target.

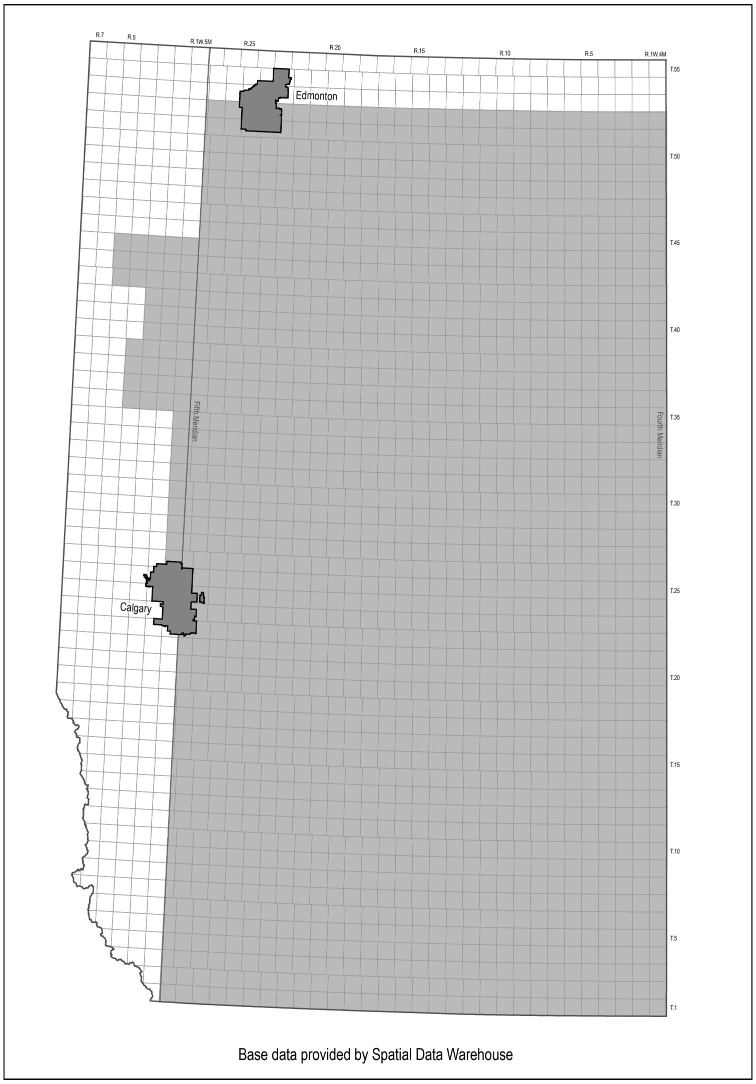


Figure 7.1 *OGCR* Schedule 13A

As provided in section 4.021(1) of the *OGCR* the AER may by order limit the number of wells that may be produced in a drilling spacing unit. This means there is no limit on well density throughout the province unless the AER orders otherwise. Where the AER has prescribed limits on the number of wells, such orders can be found on the AER's website.

The standard DSU size of one section for gas wells and one quarter section for oil wells remains the same regardless of the well density.

A block of land containing multiple, contiguous DSUs of common ownership as defined in section 1.020(2)(4) of the *OGCR* may be developed without a special well spacing approval, limited only by the standard target area on the external boundaries of that block of land. Figures showing examples of development on multiple contiguous DSUs of common ownership can be found in appendix L.

Any approved special well spacing supersedes standard DSUs, target areas, and baseline well densities described in Part 4 of the *OGCR*.

7.2.2 Fractional Tracts of Land

A well cannot produce from a fractional tract of land unless the tract is deemed to be a DSU.

In accordance with section 4.050(1) of the *OGCR*, a fractional tract of land that is equal to or greater than half the size of a drilling spacing unit, as described in section 4.010(3) of the *OGCR*, shall be deemed to be a drilling spacing unit without application to the AER.

In accordance with section 4.050(2) of the *OGCR*, if a fractional tract of land is less than half the size of a drilling spacing unit, it shall be joined with an adjacent drilling spacing unit and shall be deemed to be a drilling spacing unit without application to the AER if it meets the following criteria:

- the lands to be joined are of common ownership,
- the adjacent drilling spacing unit is the size of a drilling spacing unit as described in section 4.010(3) of the *OGCR*, and
- the adjacent drilling spacing unit is located directly to the east or west of the fractional tract of land.

The standard target areas and well densities for fractional tracts of land that are deemed DSUs would be in accordance with those prescribed in sections 4.021(1), 4.030(1)(a), 4.030(1)(b), and 4.030(2) of the *OGCR*.

7.2.3 Standard Buffer Zones for Holdings

The AER considers that consistent application of standard buffer zones in a region maximizes resource conservation, greatly enhances equity, and supports orderly and efficient development. Standard buffer zones for holdings are consistent with the standard target areas for oil and gas development throughout the province.

The standard buffers for holdings are noted below and are illustrated in detail in appendix L.

Area	Holding or unit	Standard buffer
13A	Gas	150 m on south and west boundaries of a holding or unit
All Alberta except 13A	Gas	150 m around all boundaries of a holding or unit
All Alberta	Oil	100 m around all boundaries of a holding or unit

A well producing from a buffer zone of a holding will not be subject to enforcement if the well was drilled or spud on target on or before October 6, 2011, in accordance with the buffer zone provisions of a valid holding. In this situation, a request for a well exemption is not required in an application.

Licensees are advised to keep records to demonstrate that they were in compliance with the buffer zone provisions at the time of drilling and completing a well on or before October 6, 2011.

A well that was drilled in accordance with the conditions of a holding but subsequently produces from the buffer zone due to changes in the area of the holding may be subject to enforcement for producing from within the buffer zone. This situation may arise when an operator has an approved holding that includes multiple DSUs and drills a well along the boundary between the DSUs within the holding. If the operator does not retain the mineral lease for the approved zone in the DSU adjacent to the well, the holding is realigned to reflect common ownership. Realignment of the holding boundaries would place the well within the buffer zone, causing the well to be in noncompliance. The well licensee is responsible for maintaining common ownership within each holding to ensure that no buffer issues occur.

7.2.4 Spacing and Horizontal/Multilateral Wells

The productive part of a horizontal wellbore in each DSU is considered a wellbore for the purpose of section 4.021 of the *OGCR*. The productive part of a wellbore is the portion open to the producing zone or formation/pool. Each leg of a multilateral horizontal well counts as a wellbore, as shown in figure 7.2.

If any productive portion of the horizontal wellbore is off target, the entire horizontal well is considered off target and a penalty may be applied to the well’s total production.

A horizontal well may be drilled across adjacent DSUs that have common mineral rights ownership at both the lessor and lessee levels or if a pooling agreement between the lessees and lessors is in place, as shown in figure 7.3.

The example in figure 7.2 shows two lateral legs and one vertical leg producing within a DSU. Assuming that all legs are producing from the same pool, this DSU would have three producing wells.

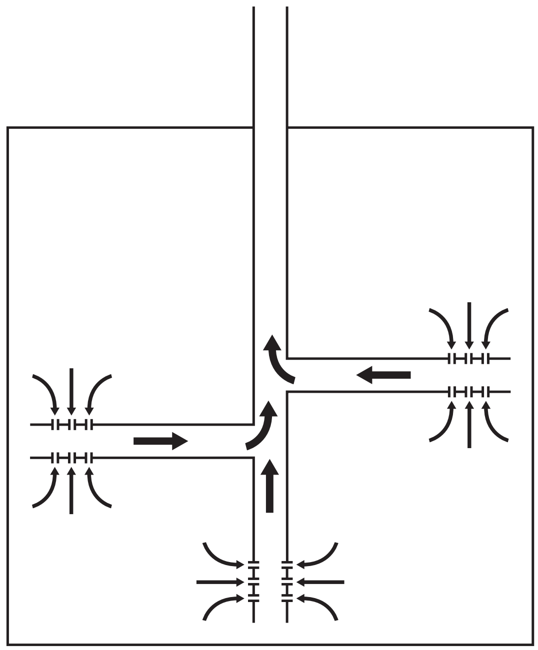


Figure 7.2 Example of producing horizontal/multilateral legs from a single DSU

If a horizontal well is drilled from target area to target area between DSUs of identical size, target area configuration, and mineral rights ownership, the corridor between target areas is deemed “on target.” However, if any productive portion of the horizontal wellbore falls outside this corridor, the entire horizontal wellbore is considered off target and a penalty may be applied to the well’s total production. Assuming that the horizontal well in this example is producing from the same pool in each quarter-section DSU, the well count would be one well per DSU. Although the example illustrates only oil DSUs with central target areas, the rule also applies to the gas DSUs for both central target and corner target areas.

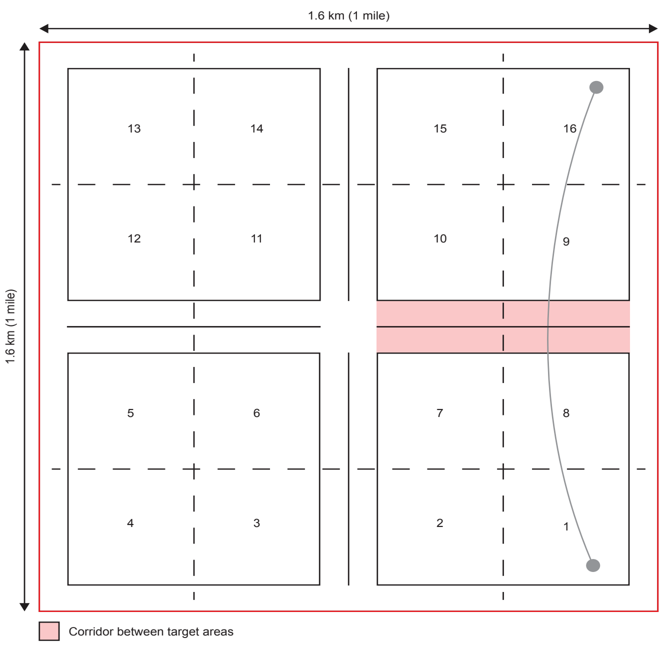


Figure 7.3 Example of a horizontal oil well drilled across adjacent quarter-section DSUs of common mineral rights ownership

7.2.5 When to File a Spacing Application

An operator wishing to develop using spacing that deviates from the standards prescribed in Part 4 of the *OGCR* must apply to the AER and obtain approval for the special spacing before beginning production. Ensure applications for special well spacing contain information that fully and clearly supports the proposed change in spacing, including meeting the *OGCR* criteria for establishing special well spacing that also clearly supports the entire area of application. Applications that do not meet the criteria for special well spacing will be closed, and those containing minimal or insufficient information to support all applied-for lands will be closed.

7.2.6 How to Make a Spacing Application

File spacing applications electronically using the Electronic Application Submission (EAS) system via the Digital Data Submission (DDS) system on the AER website, www.aer.ca, using the appropriate spacing application form (see "EAS Well Spacing Application Forms" on the AER website), which is interactive with the Well Spacing Map. Schedule 1, the form, and the applicable attachments, per section 7.5, constitute the complete application. The AER will not accept paper applications. A well spacing application filed with the AER is displayed on the Well Spacing Map following registration.

The AER validates all applications to ensure that the application requirements have been met. Incomplete applications, those containing numerous or significant errors, or those in which data is not provided in International System of Units (SI) will be **closed**.

If the AER finds that any question on the Spacing EAS form is answered incorrectly at the time of registration, the application will be **closed**.

If an application contains more than 36 sections or the equivalent in size or the applied-for formations and provisions are not the same for each area of application, the application will be **closed**.

7.2.7 Types of Spacing Applications

7.2.7.1 Holding Application

Common mineral rights ownership at both the lessor and lessee levels is a prerequisite for establishing a holding. A holding area consists of at least one DSU or whole, contiguous DSUs of common mineral ownership.

A holding application is made in accordance with section 5.190 of the *OGCR*, which allows for the establishment of a holding, and section 79(4) of the *OGCA* to suspend the DSU and target area provisions for the holding areas. The suspension of DSU and target area provisions affords the greatest flexibility to locate wells.

A request to suspend DSUs and target areas within a holding must include a well density and a buffer zone distance between a well and the boundary of the holding area. A minimum distance between wells within the holding area is not a mandatory provision but may also be considered.

Initial development plans should be considered when determining the size of an area of application. Applicants who file holding applications solely based on contiguous blocks of land containing common ownership risk future noncompliance if there is a change in mineral ownership.

Note that wells drilled in accordance with the holding boundaries could be considered off-target if the holding is rescinded and they were not drilled in accordance to the DSU and target areas, or they could be in noncompliance if the holding boundaries are realigned and they are now producing from a buffer zone. For these reasons it is very important that an applicant only file holding applications for lands that they have immediate plans to develop.

7.2.7.2 Special DSU Application

The use of holdings provides for maximum flexibility to support development plans. If the buffer zone needs to change, holding applications should be filed. However, DSUs that are subject to a compulsory pooling order do not qualify for a holding, and in these very unique cases a special DSU application may be filed to change the target area from those prescribed in the *OGCR*.

Divided mineral ownership within a DSU is not a reason to file a special DSU application. If the mineral owners are unable to voluntarily negotiate a pooling arrangement, a Compulsory Pooling application may be filed with the AER.

Applications for special DSUs will only be considered by the AER in unique situations. Therefore, an applicant wishing to file a special DSU application should contact the AER Resources Applications Group before filing.

7.2.7.3 Rescinding a Special DSU

Under section 4.040(5) of the *OGCR*, an applicant may apply to rescind an existing approved special DSU. Request to rescind a special DSU using the Rescind form. Rescinding a special DSU is necessary if an applicant wishes to use the standard DSUs and target areas set out in the *OGCR* to develop its minerals.

Minimum notification requirements prior to filing a Rescind Special DSU application are outlined in table 1. A Rescind Special DSU application must create whole contiguous standard drilling spacing units.

7.2.7.4 Rescinding a Holding

Under section 5.220(b) of the *OGCR*, an applicant may apply to rescind all or part of an existing approved holding. Request to rescind a holding using the Rescind form. Rescinding all or part of a holding may be necessary if common ownership no longer exists (also see section 7.3.1.6) or if spacing as set out in the OGCR is desired. A common example of such a situation is when a lease for a DSU within a holding boundary has expired and reverted back to the Crown. All of an existing approved holding may also be rescinded if the standard spacing prescribed in Part 4 of the *OGCR* is sufficient.

Applications to remove DSUs from holdings may only be filed for areas where the applicant has a working interest and wishes to rescind all or part of the holding in favour of the standard spacing specified in Part 4 of the *OGCR* or where a lease has expired and reverted back to the Crown. Applications to rescind holdings must be filed on behalf of all working interest owners except where the lands have reverted to the Crown.

There are no notification requirements for an application to rescind a holding.

7.2.7.5 Modify Holdings

A Modify application form must be filed when mineral ownership within an approved holding boundary is no longer common and the boundaries of the holding need to be realigned to reflect the new area of common ownership. Notification is not required when realigning holding boundaries. Applicants applying to realign holding boundaries are required to confirm common ownership. Note that lands that have reverted back to Crown cannot be rescinded using the Modify form, rather they must be rescinded using the Rescind application form. For applicants applying to realign the boundaries of a holding to reflect common ownership and to rescind lands that have reverted back to Crown, file two applications and relate them on Schedule 1 of the EAS forms.

A Modify application form should be used to remove an interwell distance provision from an existing holding and/or to amend the buffer zone of a holding to reflect the standard buffer zone for the area. This type of request would have to meet the minimum notification requirements of *Directive 065*, section 7.3.1.

7.3 Application Requirements and Expectations

7.3.1 Minimum Notification Requirements

Well spacing applications that have not met all applicable notification requirements will be closed and removed from the AER's agenda. Applications to rescind holdings or realign holding boundaries have no notification requirements.

Refer to the Notification Guidelines section of *Directive 065* for a detailed discussion on the objective, purpose, and guidelines of the notification process.

7.3.1.1 Preapplication Notification

Minimum notification requirements are outlined in the section "Resources Applications Notification Guidelines" and summarized in table 1. An application filed with the AER before the notification period has expired will be closed.

7.3.1.2 How to Notify

Examples of template notification letters are available in appendix J. The notification must provide an accurate description of the entire area of application, proposed formations/pools, and requested provisions.

7.3.1.3 Whom to Notify

Minimum notification requirements are outlined in table 1. If any of the minimum notification requirements could not be met, the applicant must provide an explanation. Notification to the Crown is not required for any well spacing application.

7.3.1.4 Evidence of Notification

Applicants requesting to establish or modify holdings are required to declare that notification of the application to all applicable mineral owners has been conducted in accordance with this directive. Applicants are not required to provide evidence of notification upon registration of a well spacing application.

The AER may request evidence of notification for any well spacing application. It is the responsibility of the working interest owner who filed the application to keep the evidence on file. Evidence would include the following:

- Letters used for notification of the application.
- A list of the mineral owners notified (do not provide names of individual Freehold mineral owners in this list unless requested by the AER; see the Mineral Rights Ownership and Notification List example in appendix K, "Special Well Spacing Attachment Examples"). The percentage of working interests must be specified for mineral owners within the area of application.

Applications that include evidence of notification will be closed except where that information has been specifically requested by the AER for an application.

Notification that is less than a year old is considered valid as long as the mineral owners in the notification area remain the same. If there is any change to mineral ownership, the new mineral owners must be notified of the application and given 15 business days to respond before an application may be filed with the AER.

7.3.1.5 Outstanding Statements of Concern

All outstanding statements of concern, both written and verbal, must be included in the application filed with the AER. In the case of a Freehold individual, the statement of concern and any related material filed must not contain confidential or sensitive personal information (e.g., medical history, financial or family issues) unless the individual whom the information is about has consented to it being provided to the AER for filing on the public record. If an individual does not provide consent, applicants should discuss with AER staff what information should be included with the application to reflect the concerns of that individual. In collecting personal information and providing it to the AER, applicants must also comply with all personal information protection legislation to which they are subject.

The application must include an explanation of how the applicant has addressed the unresolved concerns and the applicant's view of how the AER should proceed with the application.

7.3.1.6 Common Ownership

As defined by section 1.020(2)(4) of the *OGCR*, holdings require common ownership at both the lessor and lessee levels in the area of the holding. Common ownership must be maintained to ensure the validity of and preserve the equity within a holding. A farm-in or farm-out agreement has the potential to change the ownership so that it is no longer common throughout the area of a holding.

If the ownership within a holding is common at the lessor level and uncommon at the lessee level but all lessees have agreed to work within the terms of the current holding, the ownership is considered to be common for the purposes of a holding. Such agreements are handled by the mineral owners and are dealt with outside of AER procedures. Lessees are responsible for managing these agreements to mitigate any potential risk of noncompliance. In situations where the area of a holding is greater than a single DSU and there are both Freehold and Crown lessors, the ownership is not considered to be common and separate holdings must be created.

Applicants are required to declare that the mineral owners of the lessor's interests and the mineral owners of the lessee's interests throughout each applied-for holding are common or considered to be common in accordance with this directive.

The working interest owner who filed a spacing application must keep a record of the mineral ownership information at the time of application. This information would include

- the lessee map,
- the lessor map, and
- the mineral ownership and notification list.

Special well spacing attachment examples can be found in appendix K. Applications that include evidence of common ownership will be **closed** except where that information has been specifically requested by the AER for an application.

7.3.2 Minimum Equity and Conservation Requirements

An application for new holdings within a DSU must include the following:

- A discussion on how the current spacing does not allow for initial development.
- A detailed discussion on how the proposed spacing will affect hydrocarbon recovery.
- A written statement that the applicant has the petroleum and/or natural gas rights for all applied-for zones within the application area.
- If the application is for heavy oil (fluid density greater than 920 kg/m^3), a fluid analysis specifying the oil density of the native reservoir fluid.

An analysis of all data provided in support of an application must also be submitted with the application.

Applications that do not contain information to meet the criteria for special well spacing as prescribed in section 5.190 (3) of the *OGCR* and section 7.2.5 of this directive, or that contain minimal or insufficient information to support all applied-for lands, will be **closed**.

Applications containing information not in International Systems of Units (SI) units will be closed.

7.4 How the AER Processes the Application

The AER processes special well spacing applications having regard for

- location of the proposed application areas relative to previously approved spacing for the same formations and substance and
- proposed provisions.

How the application is processed may change if the AER finds that additional information is required to technically support the application.

Application Requirements

Well spacing applications must meet all of the baseline criteria outlined below and clearly meet all *Directive 065* requirements.

Minimum Baseline Criteria for Well Spacing Applications

1) Each applied-for holding must include full DSUs.
2) Standard buffer zones must be proposed for gas.
3) Standard buffer zones must be proposed for oil with the exception of heavy oil areas, where a reduced buffer zone may be considered if a supporting fluid analysis is submitted.

Any application with an outstanding statement of concern requires additional review, regardless of the processing path criteria met.

7.5 Attachments Required for a Special Well Spacing Application

Table 7.1 provides a list of common attachment types related to a spacing application. The EAS system will prompt for mandatory attachments, which depend on the type of spacing application being filed and on selections made on the spacing forms.

Ensure the content in each attachment represents the attachment type and associated description; otherwise, the application may be closed.

Table 7.1 EAS attachment types

EAS attachment type	Description
Application	Application requirements described in *Directive 065*.
Declaration of Common Ownership (optional)	A signed copy of a Declaration of Common Ownership.
Declaration of Notification (optional)	A signed copy of a Declaration of Notification.
Statements of Concern	Documentation of statements of concern.
Applicant Response to Objection	Written response by applicant to intervener.
Miscellaneous	Miscellaneous attachments in support of the application.
Fluid Analysis	An analysis of the native reservoir fluid, including the oil density.

7.6 Explanatory Notes for Application Form Questions

The spacing application forms are available on the AER website, and explanatory notes for each application type are in sections 7.6.2.5 to 7.6.2.9. The numbering below corresponds to the questions on the forms.

7.6.1 Schedule 1—Resources Applications

Schedule 1, the form, and the applicable attachments (see section 7.5) constitute the complete application. Select the application type as either Spacing: Gas or Spacing: Oil. Once selected, the Application Purpose field is enabled, and from the drop-down list select one of the following application purposes:

- New Spacing—to apply for a new area of spacing or to amend areas and/or provisions of previously approved spacing.
- Rescind Spacing—to apply to remove existing approved holdings and revert to the underlying DSUs and target areas or to remove special DSUs and revert to the standard DSUs and target areas.
- Modify Spacing—to realign holding boundaries to reflect current mineral ownership, change buffer zones to reflect the standard buffer zone for the area, and/or remove the interwell distance from an existing holding. Note that a modify spacing application cannot be used to increase well densities.

7.6.2 Spacing Form

7.6.2.1 Notification Requirements

There are no notification requirements for applications to rescind holdings or to realign holding boundaries to reflect common mineral ownership.

1) Were *Directive 065* notification templates used?

Select YES if all parties were notified (see appendix J for example notification templates).

If you select NO, conduct notification in accordance with Directive 065 notification requirements.

2) Have all parties been notified in accordance with *Directive 065*?

Select YES if all parties were contacted (see section 7.3.1.3).

Select NO if this requirement has not been met but you are still choosing to file a spacing application. You must include a "Reason for Incomplete Notification" attachment with your application.

3) What was the mailing date of the last notification letter sent?

Enter the date the last notification letter was sent. A minimum 15-business-day response period from the date the notification letter is mailed is required before an application can be registered with the AER.

4) Are there any outstanding objections or concerns?

Select YES if there are unresolved concerns or objections from one or more parties.

Select NO if there are no known unresolved concerns about the application.

5) Is the application consistent with the details in the notification?

Select YES if the application area, formations/pools, and proposed provisions in the application are consistent with those stated in notification letters.

If you select NO, you must include an explanation in the application attachment. If the AER finds that the details of the application were not properly outlined in the notification letters, the application may be closed.

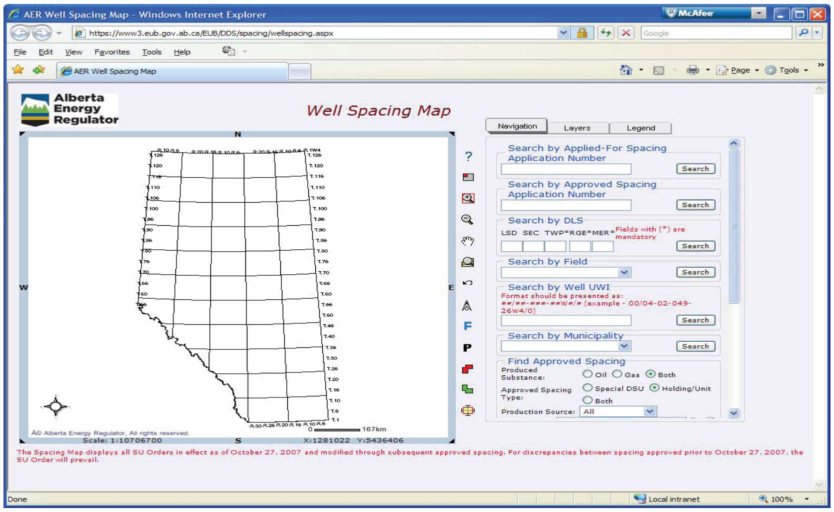
7.6.2.2 Application Type

Select one of the following:

Special application type	Description
Holding or unit	
Holding	Establish a holding comprising whole contiguous DSUs in accordance with sections 5.190 and 5.200 of the *OGCR* and suspend the DSUs and target areas in the holding in accordance with section 79(4) of the *OGCA*.
Unit	Suspend the DSUs and target area provisions within a unit or partial unit in accordance with section 79(4) of the *OGCA*.
Special DSU	Change the surface area of a DSU, in accordance with section 4.040(1) of the *OGCR*, or increase the number of wells to be produced in a DSU, in accordance with sections 4.021(1) and 4.040(1) of the *OGCR*.

7.6.2.3 Area of Application

To select your application area and applied-for formations or pools, click View Map to open the Well Spacing Map window. For information on how to do this, see Online Help Link.



7.6.2.4 Application Details

1) What is the source of production?

Select the production source—either sand or coal. Only one production source can be selected for each application. If application areas involve both production sources, file multiple applications and relate them on Schedule 1 in section 6.

Should your application be for the production of shale gas, select a production source of sand. Specify in the application attachment type that the proposed spacing is for the production of shale gas and meets the shale gas definition in *Bulletin 2009-23: Shale Gas Development—Definition of Shale and Identification of Geological Strata*.

Spacing EAS forms can be found on the AER website, and explanatory notes for each application type can be found in sections 7.6.2.5 to 7.6.2.9.

No well productivity or volumetric reserves information is required for applications to rescind a holding, to rescind a special DSU, or to modify a holding.

7.6.2.5 New Spacing Application – Holdings or Units

1) Does your area of application include entire DSUs?

Select YES if each area of application contains whole DSUs.

If you select NO, the application cannot be filed as the area of application should contain whole DSUs.

2) *Are all mineral owners of the lessor's interests and the mineral owners of the lessee's interests (if applicable) throughout each applied for holding common or considered common in accordance with* Directive 065*?*

Select YES if each applied-for holding has common mineral rights ownership at both the lessor and lessee levels as defined in section 1.020(2)(4) of the *OGCR* or ownership is considered common under *Directive 065*, section 7.2.4.

If you select NO, the application cannot be filed as common mineral rights ownership is a prerequisite to establish a holding (see section 7.2.4).

This question is not applicable if the application subtype is "Unit."

Select NO if any proposed holding does not contain production data in the applied-for formations/pools.

3) *Is the density of the oil 920 kg/m³ or greater at 15ºC?*

Heavy oil, as defined in *Directive 017: Measurement Requirements for Upstream Oil and Gas Operations*, is "crude oil production with a density of 920 kg/m^3 or greater at 15ºC." This crude oil density incorporates most of the areas of east-central Alberta, where heavy oil production operations normally occur. Heavy oil development typically requires higher well densities to maximize recovery.

Select YES if the application is for heavy oil. You should attach a Fluid Analysis that contains an analysis of the native reservoir fluid, which includes the density of the oil.

Select NO if the application is not for heavy oil.

4) *Enter the well density.*

All holding/unit applications should propose a well density. Well density is defined as the number of wells per pool per area. Enter the well density and select the well density area. Possible well density areas are

- 1 Legal Subdivision
- 2 Legal Subdivisions
- 1 Quarter Section
- 1 Half Section
- 1 Section
- Limited by Buffer Distance
- Limited by Interwell and Buffer Distances

Note that typically well density areas are equivalent to the size of the standard DSU (e.g., if the standard DSU is 1 section, the well density area would typically be per pool per 1 section).

5) The standard buffer zone distance and orientation for this area of the province is:

This is populated based on the spacing application type (Spacing: Gas or Spacing: Oil) selected on Schedule 1 and the area of application selected on the Well Spacing Map.

The standard buffer zones within the province are as indicated in the table below.

Schedule	Holding or unit	Standard buffer zone
13A	Gas	150 m on south and west boundaries of a holding or unit
All Alberta except 13A	Gas	150 m on all boundaries of a holding or unit
All Alberta	Oil	100 m on all boundaries of a holding or unit

5a) Do you want to proceed with the standard buffer zone distance and orientation?

Select YES if you are proposing the standard buffer zone as shown in the table in question 10.

Select NO to request a nonstandard buffer zone. You should enter the buffer zone distance and orientation in questions 10b and 10c and provide additional technical information supporting the request.

5b) If NO, enter the buffer zone distance.

Enter the buffer zone distance from the boundaries of each holding/unit in metres.

5c) Enter the buffer orientation.

Select the boundaries of the holding/unit that the buffer zone distance applies to.

6) Are you requesting an interwell distance?

If you select YES, enter the requested interwell distance in question 11a.

Note that an interwell distance is not required for a holding/unit spacing application.

6a) If YES, enter the interwell distance.

7.6.2.6 New Spacing Application – Special Drilling Spacing Units

1) Are you increasing the well density in the special DSU?

Select YES if you are applying to increase the well density in a special DSU. Applications to increase the well density in a special DSU will require supporting well information from wells either inside or adjacent to the area of application. This information should be provided using the EAS production and volumetric forms.

Select NO if you are not applying to increase the well density in a special DSU.

2) *The DSU size is:*

All special DSU applications will have a DSU size described as "Special DSU." The value Special DSU will be auto-populated and cannot be changed by the applicant.

3) *The standard target area locations for the special DSU are based on section 4.030(1) of the* OGCR.

The standard target areas for oil and gas are given in the following table.

Area of the province	Substance	Target area description
Inside Schedule 13A	Gas	At least 150 m from the south and west boundaries of the drilling spacing unit; section 4.030(2) of the *OGCR*.
Outside Schedule 13A	Gas	The central area within the drilling spacing unit having sides of 150 m from the sides of the drilling spacing unit and parallel to them; section 4.030(1)(a) of the *OGCR*.
All Alberta	Oil	The central area within the drilling spacing unit having sides 100 m from the sides of the drilling spacing unit and parallel to them; section 4.030(1)(b) of the *OGCR*.

The standard target areas are auto-populated on the EAS form and cannot be changed by the applicant.

4) *Are all mineral owners of the lessor's interests and the mineral owners of the lessees interests (if applicable) throughout each applied for holding are common or considered common in accordance with* Directive 065*?*

7.6.2.7 Rescind Spacing Application – Holding or Units

1) *Does your area of application include entire DSUs?*

Select YES if each area of application contains whole DSUs. Note that you can only use the Rescind application form to remove a DSUs from a holding where a leases has expired and reverted back to the Crown, or if you wish to rescind all or a portion of the holding in favour of the standard spacing specified in Part 4 of the *OGCR*.

If you select NO, the application cannot be filed.

2) *Enter the well density to be rescinded.*

The well density entered on the form should match the well density in the existing approval being rescinded. Well density is defined as the number of wells per pool per area.

Enter the well density and then select the well density area. Possible well density areas are

- 1 Quarter Legal Subdivision

- 1 Legal Subdivision
- 2 Legal Subdivisions
- 1 Quarter Section
- 1 Half Section
- 1 Section
- 2 Section
- 3 Section
- 4 Section
- Per Holding
- Limited by Buffer Distance
- Limited by Buffer and Interwell Distances
- Limited by Interwell Distance
- Per Pool
- See Special Provision

3) Enter the buffer zone distance to be rescinded.

Enter the buffer zone distance from the boundaries of each holding/unit in metres of the existing approval being rescinded. The buffer zone distance entered should match the existing approval.

3a) Enter the buffer orientation to be rescinded.

Select the boundaries of the holding/unit that the buffer zone distance applies to. The selected boundaries should match the existing approval.

4) Is there an interwell distance to be rescinded?

If you select YES, enter the approved interwell distance in question 4a.

If No, question 4a is not required.

4a) If YES, enter the interwell distance to be rescinded.

The interwell distance entered should match the existing approval.

7.6.2.8 Rescind Spacing Application – Special Drilling Spacing Units

1) *Does your area of application create standard DSUs?*

Select YES if each area of application creates standard DSUs. Note that you can only use the Rescind Application form to rescind special DSUs that contain entire standard DSUs (i.e., if the special DSU size is 2 legal subdivisions, you would have to apply to rescind two special DSUs to form a standard quarter section oil DSU to have a valid application).

If you select NO, the application cannot be filed.

2) *Enter the DSU size being rescinded.*

The DSU size entered on the form should match the DSU size in the existing approval being rescinded.

Possible DSU sizes are

- 1 Legal Subdivision
- 2 Legal Subdivisions
- 1 Quarter Section
- 1 Half Section
- 1 Section
- 2 Section
- 3 Section
- 4 Section
- Per Pool
- See Special Provision

3) *Enter the DSU orientation being rescinded.*

If a DSU size of 2 Legal Subdivisions or 1 Half Section is selected in question 2, select a DSU orientation.

Possible DSU orientations are

- North South
- East West

4) *Enter the target area description to be rescinded.*

Enter the target area description to be rescinded. The target area description entered must match the existing approval.

7.6.2.9 Modify Spacing Application – Holdings or Units

1) *Are mineral owners of the lessor's interests and the mineral owners of the lessee's interests (if applicable) throughout each applied for holding common or considered common in accordance with* Directive 065*?*

Select YES if your proposed holding contains only a single DSU or whole and contiguous DSUs of common ownership (section 5.200 of the *OGCR*).

If you select NO, the application cannot be filed.

2) *Are you removing the interwell distance provision for a previously approved holding?*

If yes, notification in accordance with *Directive 065* is required. If notification was not conducted the application cannot be filed.

If no, notification may not be required.

3) *Are you amending a previously approved buffer zone to reflect the regulation target area for the province?*

If yes, notification in accordance with *Directive 065* is required. If notification was not conducted the application cannot be filed.

4) *Are you realigning holding boundaries for a previously approved holding?*

Select YES if you are realigning holding boundaries for a previously approved holding due to a change in mineral ownership.

Select NO if you are not realigning holding boundaries.

5) *Are you changing any provisions other than those outlined in questions 2, 3, and 4?*

If YES, you should clearly describe what is being changed in section 2 of Schedule 1 in the Application Description Box. If additional information beyond what is provided in the description box is necessary to describe the requested change please provide the additional information in an application attachment.

Select NO if you are not changing any provisions other than those described in questions 2, 3, and 4.

6) *Enter the well density of the holding to be modified. Well density provisions cannot be increased using the modify application form.*

The well density entered on the form should match the well density in the existing approval. Well density is defined as the number of wells per pool per area. Enter the well density and select the well density area. Possible well density areas are

- 1 legal subdivision
- 2 legal subdivisions
- 1 quarter section
- 1 half section
- 1 section
- 2 section
- 3 section
- 4 section
- per holding
- limited by buffer distance
- limited by buffer and interwell distances
- limited by interwell distance
- per pool
- see special provision

7) *Enter the buffer zone distance of the holding(s) being modified.*

Enter the requested buffer zone distance from the boundaries of each holding in metres. The buffer zone distance entered should match the existing approval or be the standard buffer zone for the area. Applications requesting non-standard buffer zones that are not currently approved for the area of application will not be accepted using the modify application form and will be closed.

The buffer zone entered should reflect the desired buffer zone for the new holding.

7a) *Enter the buffer orientation of the holdings being modified.*

Select the boundaries of the holding that the requested buffer zone distance will apply to. The selected boundaries should match the existing approval or be the standard buffer zone orientation for the area.

The buffer zone orientation entered should reflect the desired buffer zone orientation for the new holding.

8) Are you requesting an interwell distance for the holding(s) being modified?

If you select YES, enter the interwell distance in question 8a.

If No, question 8a is not required.

8a) If YES, enter the interwell distance of the holding(s) being modified.

The interwell distance entered should reflect the desired interwell distance for the new holding.

Appendix A References

How to Use This Directive	Responsible Energy Development Act Alberta Energy Regulator Rules of Practice
When to Use Schedule 1	ST103: Field and Pool Code List Responsible Energy Development Act
Notification Guidelines	Responsible Energy Development Act Directive 056: Energy Development Application Guide, unit 1, step 4
Unit 1—Equity	
1.1 Rateable Take	Oil and Gas Conservation Act, section 36 Decision 85-5 Decision 91-8 Directive 040: Pressure and Deliverability Testing Oil and Gas Wells
1.2 Common Purchaser	Oil and Gas Conservation Act, sections 50, 51, 55, and 56 Decision 91-8
1.3 Common Carrier	Oil and Gas Conservation Act, sections 48, 55, and 56 Decision 91-8 Decision 2006-021 JP-05: A Recommended Practice for the Negotiation of Processing Fees
1.4 Common Processor	Oil and Gas Conservation Act, sections 53, 55, and 56 Decision 91-8 Decision 2006-021 JP-05: A Recommended Practice for the Negotiation of Processing Fees
1.5 Compulsory Pooling	Oil and Gas Conservation Rules, section 4.021 Oil and Gas Conservation Act, sections 80, 85, and 86 Examiner Report 91-6 Examiner Report 95-2

Unit 2—Conservation

2.1 Enhanced Recovery Scheme	Oil and Gas Conservation Act, section 39(1)(a) Directive 051: Injection and Disposal Wells IL 94-13: Progress Report Requirements – Conventional Recovery Schemes IL 96-02: Progress Report Requirements for Miscible Flood Schemes GB 2000-8: Process Changes to Disposal Well Applications Bulletin 2004-16: Chances to Enhanced Oil Recovery Application Requirements and Review Process Bulletin 2004-30: Directive 065: Resources Applications for Conventional Oil and Gas Reservoirs Enhanced Recovery Scheme—Application Changes Application Form, Requirements, and Process
2.2 Enhanced Oil Recovery Project	*Rescinded*
2.3 Enhanced Recovery Recognition and Good Production Practice	*Rescinded*
2.4 Concurrent Production	Oil and Gas Conservation Act, section 39(1)(f) Directive 060: Upstream Petroleum Industry Flaring Guide

Unit 3—Production Control

3.1 Commingled Production	Oil and Gas Conservation Rules, sections 3.050 and 3.060 ID 99-01: Gas/Bitumen Production in Oil Sands Areas—Application, Notification, and Drilling Requirements
3.3 Good Production Practice (Primary Pools)	Oil and Gas Conservation Rules, section 10.060 Monthly MRL Order Directive 060: Upstream Petroleum Industry Flaring Guide Directive 007-1: Allowables Handbook ID 99-02: Revised Policy on Administration of Oil MRLs and Overproduction
3.4 GOR Penalty Relief	Oil and Gas Conservation Rules, section 10.060
3.5 Special MRL	Oil and Gas Conservation Rules, section 10.060
3.6 Gas Allowable	Oil and Gas Conservation Rules, sections 4.050, 4,070, 10.095, and 10.300 ID 94-02: Revisions to Oil and Gas Well Spacing Administration ID 94-05: Consolidation of Regulations for Off-Target Penalty Factor Determination IL 85-10: Maximum Daily Rate of Production for Gas Wells

Unit 4—Disposal/Storage

4.1 Class I-IV Disposal	Oil and Gas Conservation Act, sections 39(1)(c) and 39(1)(d) Directive 051: Injection and Disposal Wells Directive 056: Energy and Development Application Guide Directive 058: Oilfield Waste Management Requirements for the Upstream Petroleum Industry GB 2000-8: Process Changes to Disposal Well Applications
4.2 Acid Gas Disposal	Oil and Gas Conservation Act, section 39(1)(d) Directive 051: Injection and Disposal Wells GB 2000-8: Process Changes to Disposal Well Applications
4.3 Underground Gas Storage	Oil and Gas Conservation Act, section 39(1)(b) Directive 051: Injection and Disposal Wells

Unit 5—Corporate Changes

5.1 Change of Name of Approval Holder	Oil and Gas Conservation Rules, section 15.005
5.2 Change of Approval Holder	Oil and Gas Conservation Rules, section 15.005
Unit 6—Gas and Ethane Removal	Report 87-A: Gas Supply Protection for Alberta Gas Resources Preservation Act, section 2 ST48: Alberta Gas Removal and Related Applications Bulletin 2006-42: Gas Removal Data System Compliance Process
Unit 7—Special Well Spacing	See Unit 7 for references

To obtain current AER documents, visit the AER website (www.aer.ca) or contact the AER Customer Contact Centre by phone at 403-297-8311 (toll free: 1-855-297-8311) or by fax at 403-297-7040.

Appendix B Sample Template of Company-to-Company Notification

(use for most application types except for well spacing applications)

[Date]

[Offset Company]
[Address]

Attention: [Offset Owner]

Dear [Sir/Madam]:

Application for [type of application]
[List wells or pool]

[Company X] proposes to apply to the Alberta Energy Regulator (AER) for approval to [describe the application]. A copy of the proposed application is enclosed. If you have questions about this application, do not hesitate to contact the undersigned at [telephone number]. If you have any concerns respecting the potential for the application to affect your interest, send a letter to me by fax to [facsimile number], by mail to the letterhead address, or by e-mail to [e-mail address] stating your concerns.

If you do not respond to this letter within 15 business days of receiving it, we will assume that you have no objections to the proposed application, and the AER will process the application without further contact with you.

The AER application process is a public process, and all documents filed with the AER will be placed on the public record unless otherwise authorized by the AER in accordance with section 12 of the *Alberta Energy Regulator Rules of Practice* and *Responsible Energy Development Act*.

Yours truly,

[Company]

Appendix C
Application for Gas-Oil Ratio (GOR) Penalty Relief
Form O-33

This form is to be used for smaller, less complex pools only. For detailed application requirements, see *Directive* 065, Unit 3: Production Control. A covering letter should state the reason GOR Penalty Relief is being requested and should be made on behalf of all operators in the pool.

Company Name ______________________ On behalf of (N/A ☐) ______________________

Field and Pool Name ____

Gas Conservation

Is solution gas currently being conserved? Yes ☐ No ☐

If gas conservation is planned for the future, identify the tie-in location and provide an implementation schedule.

____
____
____
____

If gas conservation is not considered feasible, include economic analysis showing capital costs, product price forecasts, total revenue (including liquids), payout time, and rate of return.

____
____
____
____

Performance Characteristics

Base MRL ______________________ m^3/d/well Base GOR ______________________ m^3/m^3

Well Location (unique well identifier)	On Production Date	Cumulative Oil Production (m^3)	Capability (m^3/d)	GOR (m^3/m^3)

Pool Reserves (company's interpretation)

Area (hectares) ______________________

N (10^3 m^3) ______________________

R_i ______________________

R_i N (10^3 m^3) ______________________

Pressure Data

P_i ____________ kPa(ga) P_b ____________ kPa(ga)

Last measured pressure ______________________ kPa(ga)

Date ____________ Well ______________________

Where appropriate, attach material balance calculations.

O-33-2009-07

Geology

Discuss the potential for further pool development.

Recompletion Potential

Comment on recompletion potential or any measures taken to reduce gas production.

Enhanced Recovery Potential

Impact on Primary Oil Recovery

Correlative Rights — Include an up-to-date map showing lessee and lessor ownership.

(Note: If pool is multiwell and of mixed ownership, concurrence in writing is required from all operators.)

Appendix D Transfer of Approval

AGREEMENT TO TRANSFER APPROVAL(S)

BETWEEN ____
(company name)

of the City of ____in the Province of Alberta,

referred to as the **Transferor**, and_______________________________ of the City
(company name)

of _____________________ in the Province of Alberta, referred to as the **Transferee**.

The **Transferor**, who is the holder of AER Approval No. ________, dated the ___day of _________ (or of the attached list of AER Approvals) for a _____________________scheme,
(type of scheme[s])

in the ________________________Field/Area, for good and valuable consideration, transfers
(field/area name)

to the **Transferee** the Approval(s) and all the **Transferor's** right and title in the Approval(s).

The **Transferee** agrees to the transfer of the AER Approval (or attached list of AER Approvals), acknowledges that it is aware of the details and conditions of the approved _____________________scheme(s), and agrees to carry out the scheme(s) as approved.
(type of scheme[s])

Dated at ________________________, on ______________________________.
(city)

Signature: _____________________________
Authorized Representative of Transferor[1]

Signature: _____________________________
Authorized Representative of Transferee

[1] If required. See unit 5, "Approval Transfers."

Appendix E AER Staff Contacts

Appendix F Enhanced Recovery (ER) Scheme Application Form

Alberta Energy Regulator

Directive 065
Enhanced Recovery Scheme

DAY MONTH YEAR ____________________ APPLICANT'S FILE NUMBER ____________________

The applicant certifies that the information provided here and in all supporting documentation is correct and in accordance with all regulatory requirements or as directed by the Alberta Energy Regulator.

SUBMISSION STATUS ____________________ SUBMISSION ID ______________ CREATION DATE ______________

1. APPLICATION TYPE

1. Type of ER scheme being proposed or amended:
   - ☐ Waterflood
   - ☐ Immiscible gas / Solvent flood
   - ☐ Miscible flood
   - ☐ Gas cycling
   - ☐ CO2 EOR storage
   - ☐ Other

2. Is this application for a new ER scheme or an amendment to an existing ER scheme approval? New ☐ Amendment ☐

3. What is the existing AER approval number proposed for amendment? ☐

4. Type of amendment:
   - ☐ Add injection well location(s)
   - ☐ Amend approval area
   - ☐ Amend approval conditions
   - ☐ Scheme termination

2. OWNERSHIP AND NOTIFICATION INFORMATION

5. The primary applicant must
   a) be the proposed approval holder for a new scheme or the current approval holder for an existing scheme, and
   b) represent all well licensees in the proposed approval area.

   Have these requirements been met? Yes ☐ No ☐

6. An ER scheme application cannot be submitted until notification of all well licensees has been completed in accordance with *Directive 065.*

   Has notification been completed in accordance with *Directive 065* ? Yes ☐ No ☐

7. Are there outstanding concerns from well licencees? Yes ☐ No ☐

   If yes, the Licensee Concerns attachment must be submitted as part of the application, in accordance with *Directive 065.*

3. PROPOSED INJECTION WELL LOCATIONS AND INJECTION

SUBMISSION STATUS ____________________ SUBMISSION ID _____________ CREATION DATE ________________

8. An ER scheme application cannot be submitted unless the proposed injection wells have been drilled.

   Have the proposed injection wells been drilled? Yes ☐ No ☐

9. An ER scheme application cannot be submitted unless the source of the proposed injection fluid has been secured.

   Has the source of the proposed injection fluid has been secured? Yes ☐ No ☐

10. Provide the following for the proposed injection well locations:

Well Licence Number	Unique Well Identifier (UWI)	Injection Interval (TVD mKB)		Porosity Interval (TVD mKB)		Fluid Interface (TVD mKB) if applicable	
		Top	Base	Top	Base	Gas/Oil	Oil/Water

11. What type of injection fluid, as indentified by Directive 051, will

- ☐ Class II - produced water (brine) without H_2S
- ☐ Class II - produced water (brine) with H_2S
- ☐ Class III - hydrocarbons or other gases without H_2S
- ☐ Class III - hydrocarbons or other gases with H_2S
- ☐ Class IV - non-saline water

11a. If an injection fluid contains H_2S and an emergency response plan (ERP) is required, the AER must ensure that an up-to-date ERP is in place prior to commencement of injection.

   Have *Directive 071* requirements been met with respect to the proposed scheme? Yes ☐ No ☐

   If no, a discussion addressing the status of the ERP must be included in the Application attachment, in accordance with *Directive 065.*

12. Will injection commence in all proposed injection wells within twelve months of reciept of approval? Yes ☐ No ☐

   If no, a discussion addressing the anticipated commencement of injection and the reason for the delay must be included in the Application attachment, in accordance with *Directive 065.*

4. PROPOSED APPROVAL AREA

13. Is the entire proposed approval area within the AER's Pool Order boundary for the subject pool? Yes ☐ No ☐

14. Does your interpretation of pool extent correspond to the AER's Pool Order boundary for the subject pool? Yes ☐ No ☐

15. Is the difference in pool delineation interpretation pertinent to the proposed ER scheme, in accordance with *Directive 065* ? Yes ☐ No ☐

   Provide a discussion on the difference in pool delineation and the pertinence to the proposed ER scheme in the Application attachment, in accordance with *Directive 065.*

5. SCHEME DETAILS

16. Is the scheme area currently administered under good production practice (GPP)? Yes ☐ No ☐

SUBMISSION STATUS ____________ SUBMISSION ID ____________ CREATION DATE ____________

17. Will produced gas from the ER scheme area be conserved, in accordance with Directive 060 requirements? Yes ☐ No ☐

18. What is the proposed voidage replacement ratio (VRR), on a monthly basis, for the scheme?

The AER normally specifies a cumulative VRR of 1.0 from production initiation as the upper bound, and a monthly VRR greater than a level chosen by the applicant as the lower bound. A technical justification is required if the elected cumulative VRR is greater than 1.0 or the monthly VRR target is lower than 0.2.

19. Is or will any gas cap gas be produced from the subject pool during the operation of the ER scheme? Yes ☐ No ☐

If yes, include a discussion on the potential for fluid migration into the gas cap in the Application attachment, in accordance with *Directive 065.*

20. Is gas cap gas currently being produced from the scheme area? Yes ☐ No ☐

20a. Has the appropriate concurrent production (CCP) approval been issued? Yes ☐ No ☐

20b. An application for CCP is required.

Has an application for CCP been registered? Yes ☐ No ☐

20c. If yes, provide the CCP application number.

6. WELL DETAILS

21 How many wells are being applied for?

22. Are there any changes to the voidage replacement ratio clause being requested? Yes ☐ No ☐

22a. If yes:

Does the VRR on the basis of cumulative production and injection volumes following the commencement of production exceed 1.0? Yes ☐ No ☐

Is the minimum monthly VRR less than 0.2 on a twelve-month rolling average basis? Yes ☐ No ☐

A technical justification is required if you answered YES to any part of 22a.

23. Is the maximum wellhead injection pressure (MWHIP) being requested based on the default given in *Directive 065,* appendix O, table 1? Yes ☐ No ☐

23a. If no, is the requested MWHIP based on a conclusive step-rate injectivity or in situ stress test as per *Directive 065,* appendix O, or *Directive 040,* section 4.7? Yes ☐ No ☐

23b. If no, is the requested MWHIP based on 8× TVD? Yes ☐ No ☐

24. Does the injection fluid contain hydrogen sulphide (H_2S) or carbon dioxide (CO_2)? If yes, answer the following subquestions. Yes ☐ No ☐

24a. Is the maximum CO_2 and H_2S concentrations disclosed in the application? Yes ☐ No ☐

24b. Is the water analysis included with the application? Yes ☐ No ☐

24c. If involving gas injection, is the gas analysis report included with the application for ER Schemes that include gas injection? Yes ☐ No ☐

Note that clauses limiting the maximum concentrations of CO_2 and H_2S will be added to any approval.

25. Are there open hole abandoned wells penetrating the injection zone within an 800 m Yes ☐ No ☐

radius of the proposed injection wells?

25a. If yes, is cement plug information provided for the open hole abandoned wells? Yes ☐ No ☐

25b. If yes, do the cement plugs in the open hole abandoned wells cover the entirety of the zone into which injection will occur? Yes ☐ No ☐

26. Are there wells penetrating the injection zone within 50 m of the proposed injection wells? Yes ☐ No ☐

26a. If yes, does the casing collapse rating of all wells within 50 m of the proposed injection wells exceed the sandface equivalent MWHIP proposed? Yes ☐ No ☐

27. Are the injection completions in the proposed injection wells assigned by the AER to the pool for which enhanced recovery will occur? Yes ☐ No ☐

28. Are the propose injection wells on freehold land? Yes ☐ No ☐

28a. If yes, has a copy of the Crown indemnification letter been included with the application? Yes ☐ No ☐

29. Will the proposed injection occur into a formation above the BGWP? Yes ☐ No ☐

30. Are there active producing wells within the scheme area? Yes ☐ No ☐

Appendix G Gas and Ethane Removal Forms

Long-Term Gas Removal Application

Short-Term Gas Removal Application

Short-Term Ethane Removal Application

These forms have been removed from the directive and can instead be found on the directive's landing page, www.aer.ca > Regulating Development > Rules and Directives > Directives > Directive 065.

Appendix H Gas Reserves Data Sheet

Gas Reserves Data Sheet

Alberta Energy Regulator

GAS VOLUMES AT 101.325 kPa AND 15°C

DATE YR/MO/DAY

SUBMITTED BY

FIELD

POOL

ZONE

TOP OF PAY K.B. S.L.

BASE OF GAS PAY K.B. S.L.

POOL MEAN K.B.

FORMATION DEPTH S.L.

TYPE WELL (LOCATION) W

TYPE OF RESERVE
- ☐ ASSOCIATED
- ☐ NONASSOCIATED
- ☐ SOLUTION

AVERAGE POROSITY SOURCE

CUTOFFS POROSITY SOURCE

PERMEABILITY mD

GAS SATURATION (Sg) = 1 - (S_W + S_O)

S_W SOURCE

S_O SOURCE

INITIAL RESERVOIR PRESSURE, P_i SOURCE

RESERVOIR TEMPERATURE SOURCE

Z P_r SOURCE

T_r

GAS ANALYSIS P_c, kPa Tc, K

P_c', kPa Tc', K

RELATIVE DENSITY SOURCE

RESERVOIR CONSTANT (m³/m³) $= Ø \times Sg \times \frac{Pi}{101.325} \times \frac{288.15}{T} \times \frac{1}{Z}$

RECOVERY FACTOR SOURCE

SURFACE LOSS FACTOR SOURCE

RAW GAS COMPOSITION IN MOLE FRACTIONS

N_2 | CO_2 | H_2S | H_2 | H_e | C_1 | C_2 | C_3 | iC_4 | nC_4

C_5 | C_6 | C_7+ | SOURCE

GROSS HEATING VALUE OF MARKETABLE GAS, MJ/m³

SOURCE

STOIP, 10³m³ = 10AhØ (1-Sw) $\frac{1}{B_{oi}}$

GOR SOURCE

$1/B_{oi}$ SOURCE

ADDITIONAL COMMENTS

RESERVE ESTIMATE - INITIAL CONDITIONS

	PROVEN	PROBABLE
G/W, metres SL		
G/O, metres SL		
AREA, hectares		
h, metres		
ROCK VOLUME, 10⁴m³		
Ø, fraction		
GAS SAT, fraction		
P_i, k Pa		
T, K		
Z		
RESERVOIR CONSTANT, m³/m³		
IGIP, 10⁶m³		
RECOVERY FACTOR, fraction		
PRODUCIBLE, 10⁶m³		
SURFACE LOSS FACTOR, fraction		
MARKETABLE, 10⁶m³		
INITIAL ESTABLISHED MARKETABLE, 10⁶m³		
MARKETABLE GAS PRODUCED, 10⁶m³		
REMAINING ESTABLISHED MARKETABLE, 10⁶m³		
REMAINING ESTABLISHED MARKETABLE UNDER CONTRACT, 10⁶m³		
EFFECTIVE DATE, YR/MO/DAY		

– O

STOIP, 10³m³	
GOR, m³/m³	
GIP, 10⁶m³	
RECOVERY FACTOR, fraction	
PRODUCIBLE, 10⁶m³	
SURFACE LOSS FACTOR, fraction	
MARKETABLE, 10⁶m³	
MARKETABLE GAS PRODUCED, 10⁶m³	
REMAINING ESTABLISHED MARKETABLE, 10⁶m³	
EFFECTIVE DATE YR/MO/DAY	

STOIP = STOCK TANK OIL IN PLACE

GOR = INITIAL DISSOLVED GAS-OIL RATIO

Appendix I EAS Well Spacing Application Forms and Explanatory Notes

New Spacing Application—Holdings or Units

New Spacing Application—Special Drilling Spacing Units

Rescind Spacing Application—Holdings or Units

Rescind Spacing Application—Special Drilling Spacing Units

Modify Spacing Application—Holdings or Units

These forms have been removed from the directive and can instead be found on the directive's landing page, www.aer.ca > Regulating Development > Rules and Directives > Directives > Directive 065.

Appendix J Special Well Spacing Notification Template Examples

Lessees and Unleased Freehold Notification Letter

Leased Individual Freehold Notification Letter

Notification letters are not to be submitted with the application unless requested by the AER.

Lessees and Unleased Freehold Notification Letter

[Date]

Dear [Sir/Madam]:

[APPLICANT NAME]
[SPECIAL [GAS/OIL] WELL SPACING]
[FIELDs]
[FORMATIONs/POOLs]
[DLS LAND DESCRIPTION]

[Applicant/Consultant on behalf of Applicant] will be applying to the Alberta Energy Regulator (AER) under [section] of the *Oil and Gas Conservation Act* [and/or] [section] of the *Oil and Gas Conservation Rules* to change the subsurface well spacing for the production of [gas/oil] from the [formations/pools] in the noted lands [list lands in the above title and/or provide attachment/map]. AER *Directive 065: Resources Applications for Oil and Gas Reservoirs* requires that all mineral owners within the applied-for formation in the area of application and one (1) drilling spacing unit (DSU) surrounding the area of application receive notification of a well spacing application.

[Applicant/Consultant on behalf of Applicant] proposes that within the area of application, the existing [gas/oil] well spacing be changed from [the current spacing in place] to the following:

Example 1: Holding

Establish a holding constituting [DLS land description] for the production of [gas/oil] from the [applied-for formations/pools] subject to:

A producing well will be at least [X] metres from the boundaries of the holding.

There will be a maximum of [X] producing wells per pool per [DSU size].

A producing well will be at least [X] metres from other wells producing from the same pool. (Only applicable if requesting an interwell distance.)

The following well UWIs [XX/XX-XX-XXX-XX-WX] will be exempt from the [buffer zone and/or interwell distance].

Example 2: Rescind Special DSUs

Re-establish standard drilling spacing units in accordance with Part 4 of the *OGCR* of [DSU size] [and if applicable orientation], with the target area being [target areas] for the production of [oil/gas] in the [applied-for formations/pools] in [DLS land description].

[Brief Discussion of Reason for Application]

Any concerns and/or questions regarding this application are to be directed to [applicant contact person and phone number]. You may also send your concerns in writing to [applicant's address] or by fax or e-mail within 15 business days of receiving this letter. [Applicant] will contact you to discuss your concerns. Should your concerns remain unresolved, they will be included as a submission to the application when filed with the AER.

Under section 13 of the *Alberta Energy Regulator Rules of Practice*, all documents filed with the AER in connection to an application must be placed on the public record, which may be accessible on the Internet. As such, you should not include any confidential or sensitive personal information (e.g., health issues, financial position, family issues) in documents submitted to us or the AER that you do not want to appear on the public record. However, any party may, before filing the document, submit a request to the AER for confidentiality of documents under section 13(2). The AER may grant a request for confidentiality on any terms it considers appropriate, subject to the *Freedom of Information and Protection of Privacy Act*.

In the absence of a response to this letter within 15 business days of receiving it, we will proceed to file the application with the AER.

After the application has been registered with the AER, copies can be obtained by contacting the undersigned or can be viewed electronically by accessing the IAR Query under Systems & Tools on the AER website at www.aer.ca.

Any questions regarding the AER process should be directed to the AER Customer Contact Centre at 403-297-8311 or 1-855-297-8311 (toll free).

Yours truly,

[Applicant]

Leased Individual Freehold Notification Letter

[Date]

Dear [Sir/Madam]:

[APPLICANT NAME]
[SPECIAL [GAS/OIL] WELL SPACING]
[FIELDs]
[FORMATIONs/POOLs]
[DLS LAND DESCRIPTION]

[Applicant/Consultant on behalf of Applicant] will be applying to the Alberta Energy Regulator (AER) under [section] of the *Oil and Gas Conservation Act* [and/or] [section] of the *Oil and Gas Conservation Rules* to change the subsurface well spacing for the production of [gas/oil] from the [formations/pools] in the noted lands [list lands in the above title and/or provide attachment/map].

Records indicate that you are a Freehold mineral owner in [DLS land description] and your minerals are leased to [Company]. AER *Directive 065: Resources Applications for Oil and Gas Reservoirs* requires that all Freehold mineral owners within the applied-for formations in the area of application and one (1) drilling spacing unit (DSU) surrounding the area of application whose rights are leased receive notification of the subject application. The purpose of this notification is to provide you with information regarding potential development and to support ongoing dialogue between you and the lessee of your minerals.

[Applicant/Consultant on behalf of Applicant] proposes that within the area of application the existing [gas/oil] well spacing be changed from [the current spacing in place] to the following:

Example 1: Holding

Establish a holding constituting [DLS land description] for the production of [gas/oil] from the [applied-for formations/pools] subject to:

A producing well will be at least [X] metres from the boundaries of the holding.

There will be a maximum of [X] producing wells per pool per [DSU size].

A producing well will be at least [X] metres from other wells producing from the same pool. (Only applicable if requesting an interwell distance.)

The following well UWIs [XX/XX-XX-XXX-XX-WX] will be exempt from the [buffer zone and/or interwell distance].

Example 2: Rescind Special DSUs

Re-establish standard drilling spacing units in accordance with Part 4 of the *OGCR* of [DSU size] [and if applicable orientation], with the target area being [target areas] for the production of [oil/gas] in the [applied-for formations/pools] in [DLS land description].

[Brief Discussion of Reason for Application]

The lessee of your minerals has also been notified of this application. Therefore, if you have any questions regarding the effect of this application on your interests, please contact your lessee. If discussions between you and your lessee do not address your concerns, please clearly state your concerns in writing to the undersigned at [applicant's address] or by fax or e-mail within 15 business days from the date you receive this letter. Your concerns will be included as a submission to the application when filed with the AER.

OR

As [Company] is the lessee of your offsetting minerals in [DLS land description], should you have questions regarding the effect of this application on your minerals, please contact [applicant contact person and phone number]; you may also send your concerns in writing to [applicant's address] or by fax or e-mail within 15 business days from the date you receive this letter. If discussions do not address your concerns, they will then be included as a submission to the application when filed with the AER.

Under section 13 of the *Alberta Energy Regulator Rules of Practice*, all documents filed with the AER in connection to an application must be placed on the public record, which may be accessible on the Internet. As such, you should not include any confidential or sensitive personal information (e.g., health issues, financial position, family issues) in documents submitted to us or the AER that you do not want to appear on the public record. However, any party may, before filing the document, submit a request to the AER for confidentiality of documents under section 13(2). The AER may grant a request for confidentiality on any terms it considers appropriate, subject to the *Freedom of Information and Protection of Privacy Act*.

After the application has been registered with the AER, copies can be obtained by contacting the undersigned or can be viewed electronically by accessing the IAR Query under Systems & Tools on the AER website at www.aer.ca.

Any questions regarding the AER process should be directed to the AER Customer Contact Centre at 403-297-8311 or 1-855-297-8311 (toll free).

Yours truly,

[Applicant]

Appendix K Special Well Spacing Attachment Examples

Lessor Map and Notification Area

Lessee Map and Notification Area

Mineral Rights Ownership and Notification List

Attachments described in appendix K are not to be submitted with the application unless requested by the AER.

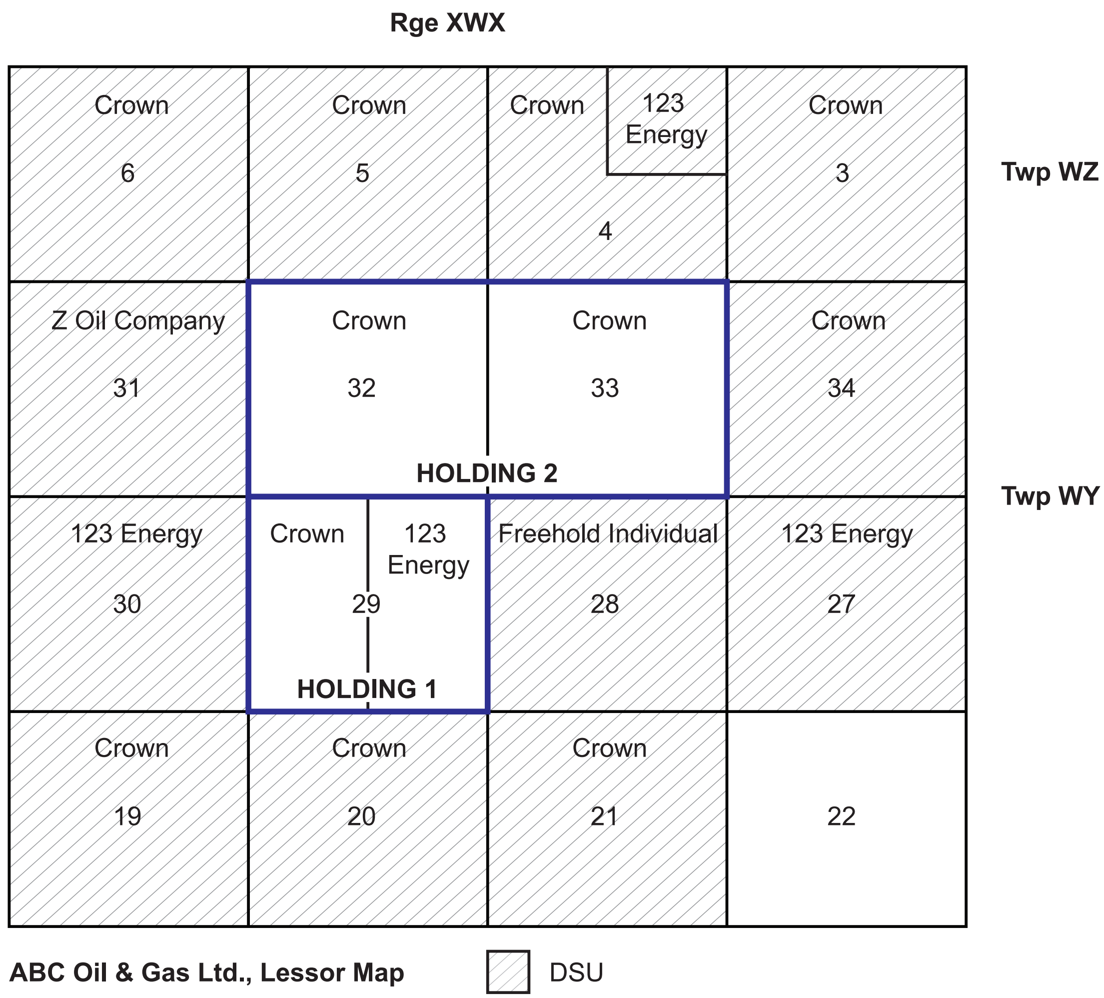
Lessor Map and Notification Area

Show only the lessors for the substance and formations/pools being applied for within the application area and one DSU around the application area. The application area must be clearly outlined on the map and the information must be accurate and shown on a map of sufficient scale to facilitate a quick review of the mineral ownership.

For areas with complex ownership, a map coded to a list of mineral owners may be used. Do not send title search documents.

In this map, the notification area includes Holding 1, Holding 2, and 1 DSU around the application area.

Example: Lessor Map for NG in the Rock Creek Formation



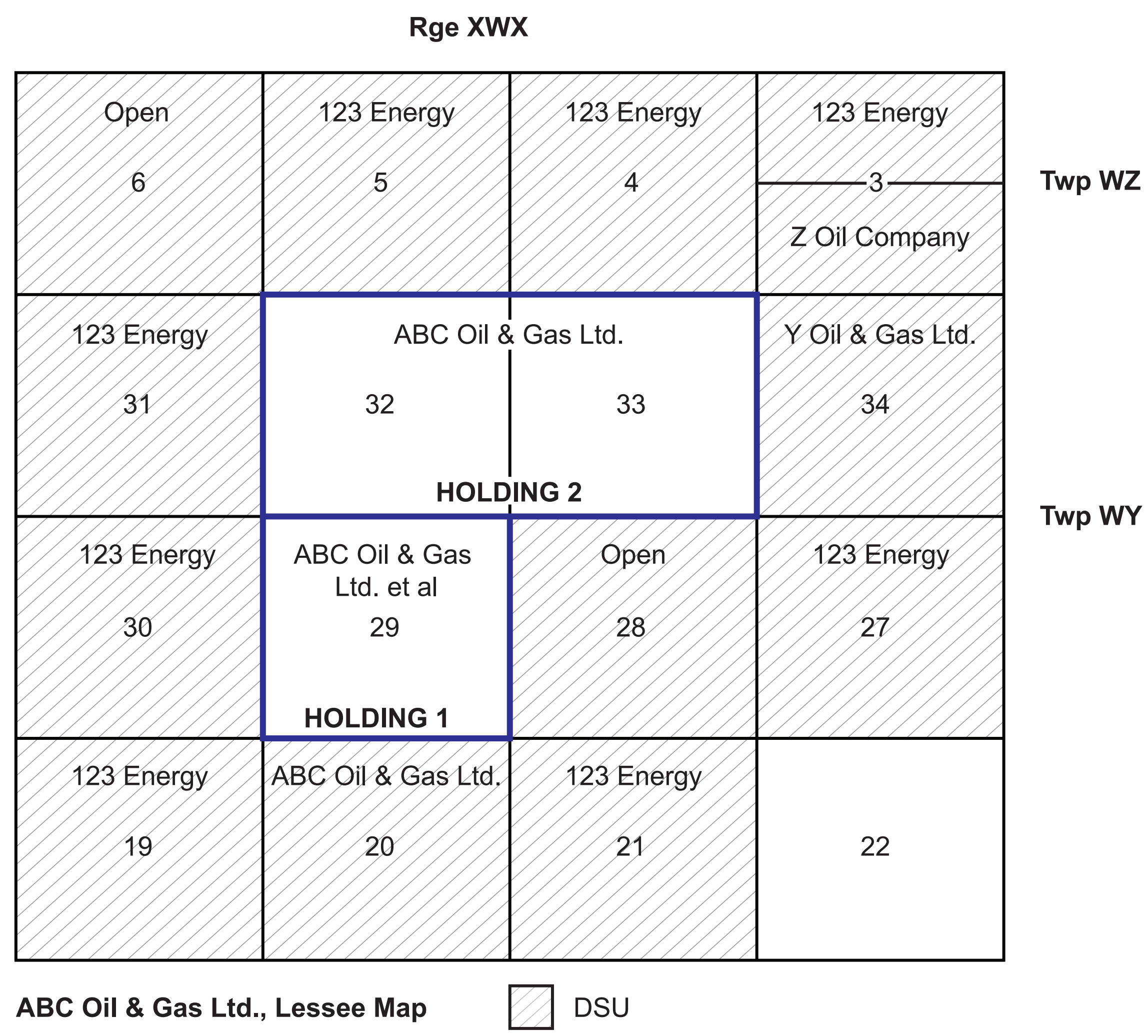
Lessee Map and Notification Area

Show only the lessees for the substance and formations/pools being applied for within the application area and one DSU around the application area. The application area must be clearly outlined on the map and the information must be accurate and shown on a map of sufficient scale to facilitate a quick review of the mineral ownership.

For areas with complex ownership, a map coded to a list of mineral owners may be used. Do not send title search documents.

In this map the notification areas are Holding 1, Holding 2, and 1 DSU around the application area.

Example: Lessee Map for NG in the Rock Creek Formation



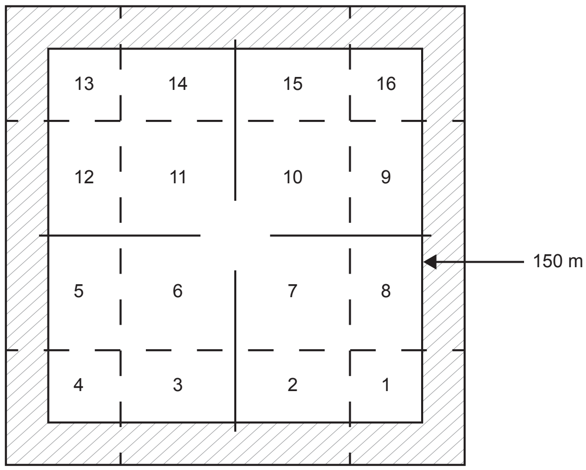
Mineral Rights Ownership and Notification List

List all mineral rights owners who have oil, gas, and coal rights in the applied-for formations/pools and were notified of your application. The list must include the legal land description of each mineral owner, their working interest, and a description of their mineral rights. (Addresses of mineral owners are not required.) This list is in addition to the lessor and lessee maps.

Mineral Rights Ownership and Notification List (Example for Rock Creek Formation)				
AREA OF APPLICATION				
Location	**Lessor**	**Lessee**	**Working Interest**	**Mineral Right(s)**
HOLDING 1				
TwpWY-RgeX WX: Sec 29 E½	123 Energy	ABC Oil & Gas Ltd.	50%	P&NG surface to basement
		Z Oil Company	50%	P&NG surface to basement
TwpWY-RgeX WX: Sec 29 W½	Crown	ABC Oil & Gas Ltd.	50%	P&NG surface to basement
		Z Oil Company	50%	P&NG surface to basement
HOLDING 2				
TwpWY-RgeX WX: Sec 32	Crown	ABC Oil & Gas Ltd.	100%	P&NG surface to base Rock Creek
TwpWY-RgeX WX: Sec 33	Crown	ABC Oil & Gas Ltd.	100%	P&NG surface to base Rock Creek
1 DSU SURROUNDING AREA OF APPLICATION				
Location	**Lessor**	**Lessee**	**Mineral Right(s)**	
Twp WY-RgeX WX: Sec 19	Crown	123 Energy	P&NG surface to basement	
Twp WY-RgeX WX: Sec 20	Crown	ABC Oil & GasLtd.	P&NG Rock Creek formation	
Twp WY-RgeX WX: Sec 21	Crown	123 Energy	P&NG surface to basement	
Twp WY-RgeX WX: Sec 27	123 Energy	123 Energy	P&NG surface to basement	
Twp WY-RgeX WX: Sec 28	Freehold Individual	Open	P&NG Rock Creek formation	
Twp WY-RgeX WX: Sec 30	123 Energy	123 Energy	P&NG surface to basement	
Twp WY-RgeX WX: Sec 31	Z Oil Company	123 Energy	P&NG surface to basement	
Twp WY-RgeX WX: Sec 34	Crown	Y Oil & Gas Ltd.	NG Rock Creek formation	
Twp WY-RgeX WX: Sec 34	Crown	XYZ Oil	Petroleum Rock Creek formation	
Twp WZ-RgeX WX: Sec 3 N½	Crown	123 Energy	P&NG surface to basement	
Twp WZ-RgeX WX: Sec 3 S½	Crown	Z Oil Company	P&NG surface to base Nordegg	
Twp WZ-RgeX WX: Sec 4 S½, NW 1/4	Crown	123 Energy	P&NG surface to basement	
Twp WZ-RgeX WX: Sec 4 NE 1/4	123 Energy	123 Energy	P&NG surface to basement	
Twp WZ-RgeX WX: Sec 5	Crown	123 Energy	P&NG surface to basement	
Twp WZ-RgeX WX: Sec 6	Crown	Open	Coal surface to basement	
Twp WZ-RgeX WX: Sec 6	Crown	Open	P&NG surface to basement	

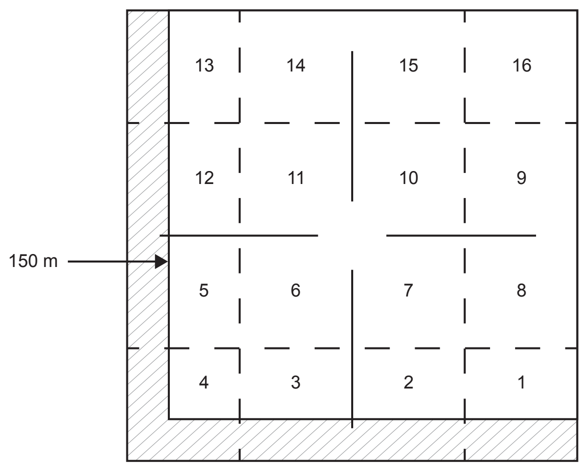
Appendix L Standard Target Areas and Buffer Zones

For Gas Production – Outside Schedule 13A Area



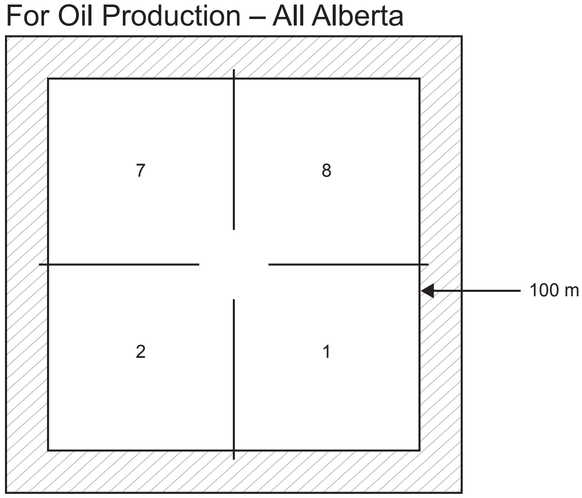
Standard gas DSU with target area 150 m from all boundaries

For Gas Production – Within Schedule 13A Area



Standard gas DSU with target area 150 m from south and west boundaries

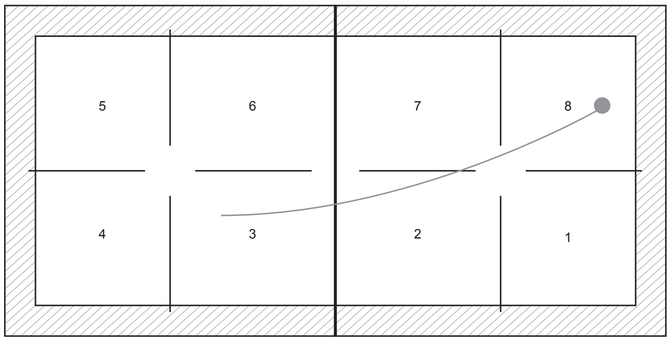
For Oil Production – All Alberta



Standard oil DSU with target area 100 m from all boundaries

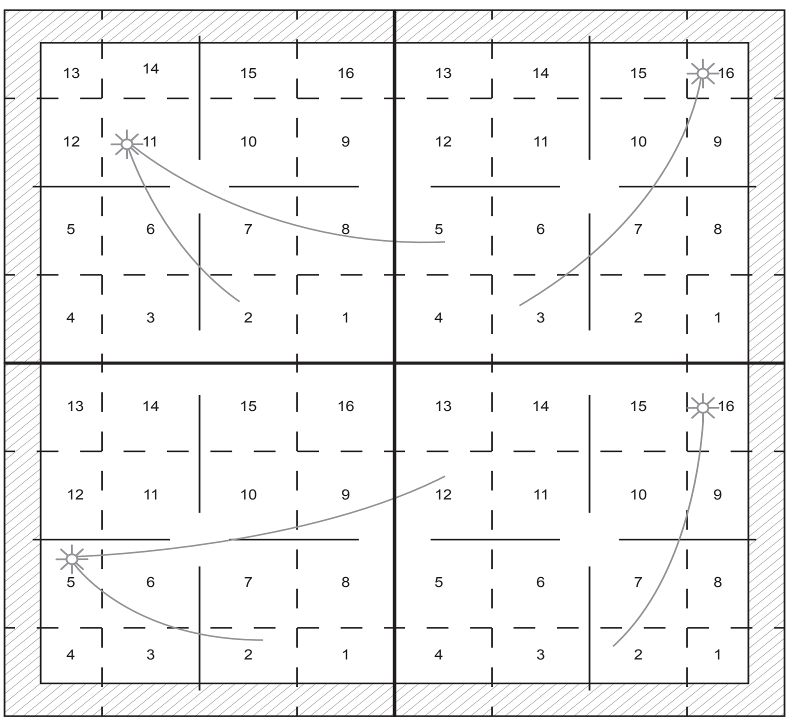
Examples of Development on Multiple Contiguous DSUs of Common Ownership

Example of a horizontal oil well drilled across two adjacent quarter-section DSUs of common mineral ownership.



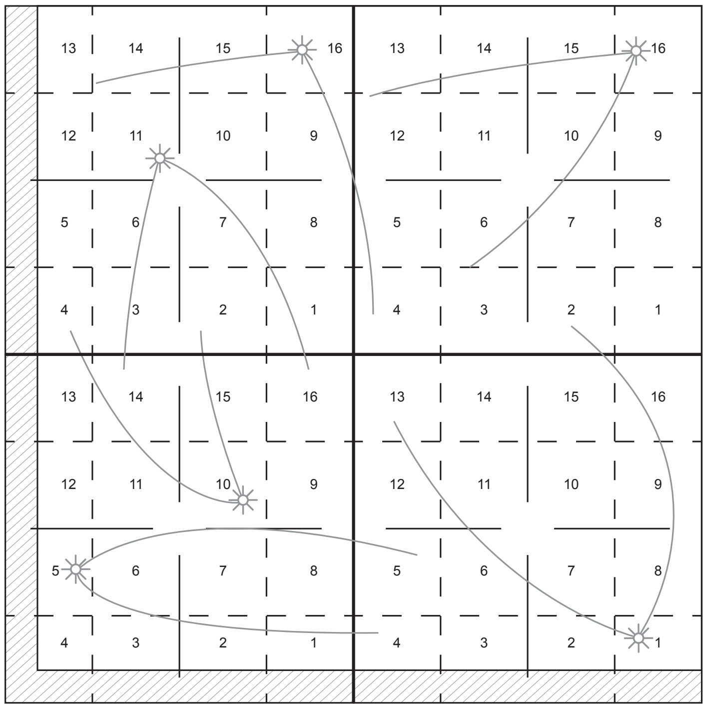
1/4 section oil DSUs: Target area – all boundaries 100 m

Example of horizontal gas wells drilled in a four-section contiguous block having common mineral ownership outside the Schedule 13A area.



1 section gas DSUs: Target area – all boundaries 150 m

Example of horizontal gas wells drilled in a four-section contiguous block having common mineral ownership within the Schedule 13A area for zones that have no well density restrictions.



1 section gas DSUs: Target area – south and west boundaries 150 m

Appendix M Target Area Descriptions for Special Well Spacing Before October 6, 2011

DSU size	Target area *OGCR* section	Target area description
One section	Central area 4.030(1)(a)	Central part of the section having sides 300 m from the boundaries of the section and parallel to them
	Central area 4.030(2)(a)	Central part of the section having sides 300 m from the boundaries of the section and parallel to them
One half section	Southwest or northeast quarter section 4.030(1)(b)	Central part of the southwest or northeast quarter section having sides 200 m from the boundaries of the quarter section and parallel to them
	LSD 6 or 16 4.030(2)(b)	Consists of LSD 6 or 16
One quarter section	Central area 4.030(1)(b)	Central part of the quarter section having sides 200 m from the boundaries of the quarter section and parallel to them
	LSD 6, 8, 14, or 16 4.030(2)(c)	Consists of LSD 6, 8, 14, or 16
	Southwest LSD 4.030(1)(c)	Central part of the southwest legal subdivision of the quarter section having sides 100 m from the boundaries of the legal subdivision and parallel to them
Two legal subdivisions	Southwest or northeast LSD 4.030(1)(c)	Central part of the southwest or northeast legal subdivision of the quarter section having sides 100 m from the boundaries of the legal subdivision and parallel to them
	Northwest quarter of the southwest or northeast LSD 4.030(2)(d)	The northwest quarter of the southwest or northeast legal subdivision of the quarter section
One legal subdivision	Central area 4.030(1)(c)	Central part of the legal subdivision having sides 100 m from the boundaries of the legal subdivision and parallel to them
	Northwest quarter of the LSD 4.030(2)(e)	Consists of the northwest quarter of the legal subdivision

Appendix N Special Well Spacing Declaration Template Examples

Declaration of Common Ownership

Declaration of Notification

DECLARATION OF COMMON OWNERSHIP

__________________________________, as applicant, hereby declares that the mineral
(company name)

owner(s) of the lessor's interests and the mineral owner(s) of the lessee's interests throughout each applied-for holding are common or considered to be common in accordance with *Directive 065: Resources Applications for Oil and Gas Reservoirs*.

Dated at ________________, _____________________on ____________________.
(city) *(province)*

Signature: ________________________
Authorized Representative

____
(print name)

____
(company name)

DECLARATION OF NOTIFICATION

________________________________, as applicant, hereby declares that notification of
(company name)

the application has been conducted in accordance with *Directive 065: Resources Applications for Oil and Gas Reservoirs*, with all applicable mineral owners having been notified.

Dated at ________________, ____________________on _______________________.
(city) *(province)*

Signature: ________________________
Authorized Representative

____
(print name)

____
(company name)

Appendix O Step-Rate Injectivity Test

The most common method of testing a zone to determine the maximum wellhead injection pressure is a step-rate injectivity test. The following standard procedure for carrying out a step-rate injectivity test is recommended:[1]

1) Before commencing the test, ensure that the well has been shut in long enough for the bottomhole pressure to be reasonably close to the formation pressure. If the well is on injection, reduce the rate to a level that allows the bottomhole pressure to stabilize. Injection should continue long enough to achieve a stabilized pressure.
2) The first injection period must be long enough to clearly overcome wellbore storage and achieve radial flow conditions. A stabilized pressure will indicate that radial flow conditions have been achieved. The value recorded at this stabilized pressure will be the first point on the plot. The time required to achieve this stabilized pressure must then be applied to all subsequent injection periods.
3) Apply five successively higher injection rates, each of the same duration as the first injection period. Record the injection rate, pressure, and elapsed time for each rate step. A minimum of five steps are required to clearly identify the absence or presence of an inflection point that indicates a fracture in the formation. At least two injection rate pressure combinations greater than the fracture pressure are necessary to confirm that the formation fracture pressure has been exceeded.
4) Plot the stabilized pressures and injection rates graphically. Draw a straight line with a constant slope through each stabilized pressure. The point of inflection should indicate the formation fracture pressure.

Include any continuous pressure and injection data, if recorded, when submitting the step-rate test data and analysis.

Note that step-rate test data conducted after a hydraulic fracture stimulation may be inconclusive, and may not be acceptable for determining fracture pressure.

Default Maximum Wellhead Injection Pressure

In the absence of step-rate injectivity test data or analogous test data, maximum wellhead injection pressure (MWHIP) will be set in accordance with the following table. These wellhead pressures are based on a statistical analysis of province-wide fracture data. The fracture pressure used to calculate the wellhead pressures is conservative and based on a confidence level at the 90th percentile that injection at this pressure will not fracture the formation.

[1] Singh, P.K., Agarwal, R.G., and Jrase, L.D. "Systematic design and analysis of step-rate tests to determine formation parting pressure." SPE paper 16798 presented at the 62nd Annual Technical Conference and Exhibition of the Society of Petroleum Engineers, Dallas, Texas, September 1987.

Table 1. Maximum allowable wellhead injection pressure

Depth interval (m)	Wellhead pressure (kPag*)	Depth interval (m)	Wellhead pressure (kPag)
401–450	3000	1451–1500	4400
451–500	3200	1501–1550	4450
501–550	3300	1551–1600	4500
551–600	3450	1601–1650	4550
601–650	3550	1651–1700	4600
651–700	3600	1701–1750	4650
701–750	3650	1751–1800	4700
751–800	3700	1801–1850	4800
801–850	3750	1851–1900	5200
851–900	3800	1901–1950	5650
901–950	3850	1951–2000	6000
951–1000	3900	2001–2050	6400
1001–1050	3950	2051–2100	6750
1051–1100	4000	2101–2150	7150
1101–1150	4050	2151–2200	7550
1151–1200	4100	2201–2250	7950
1201–1250	4150	2251–2300	8350
1251–1300	4200	2301–2350	8750
1301–1350	4250	2351–2400	9150
1351–1400	4300	2401–2450	9500
1401–1450	4350	2450–2500	9900

* kPag = kilopascals (gauge).

If the depth interval is shallower than 400 m, calculate the MWHIP as follows:

Wellhead pressure = 7.5 × depth

where

wellhead pressure = pressure at the wellhead in kPag

depth = top of injection or disposal interval in metres total vertical depth (m TVD)

In cases where the depth interval is deeper than 2500 m, calculate the MWHIP as follows:

Wellhead pressure = 4.0 × depth

where

wellhead pressure = pressure at the wellhead in kPag

depth = top of injection or disposal interval in m TVD

Wellhead pressures in this table assume that fluids being injected or disposed have a pressure gradient of gradient of 10.52 kPag per metre (kPag/m). Any loss in pressure as a result of friction was not considered when estimating the wellhead pressures in the table. For fluids of a different gradient, the wellhead pressure can be revised as follows:

$$(MWHIP)_{revised} = (MWHIP)_{table} + [(10.52 - gradient) \times depth]$$

where

$MWHIP_{revised}$ = estimate based on a fluid gradient other than 10.52 kPag/m

$MWHIP_{table}$ = estimate based on a fluid gradient of 10.52 kPag/m

gradient = actual fluid gradient in kPag/m

depth = top of injection or disposal interval in m TVD

Appendix P MMV Principles and Objectives for CO_2 Sequestration Projects

Principles

What is a Monitoring, Measurement, and Verification Plan?

Monitoring and measurement are surveillance activities necessary for ensuring the safe and reliable operation of a CO_2 sequestration project. Verification refers to the comparison of measured and predicted performance, which is also known as conformance. The purpose of monitoring, measurement, and verification (MMV) is to address health, safety, and environmental risks; evaluate sequestration performance; and provide evidence that the site is suitable for closure. MMV is central to CO_2 sequestration risk management, and MMV plans include a risk management plan containing the risk identification, assessment, and management activities specific to the CO_2 sequestration project.

An MMV plan sets out the monitoring, measurement, verification, and risk-management activities that a project proponent will undertake for the term of the evaluation permit/agreement or carbon sequestration lease/agreement. MMV plans are developed by the project operator in response to the risks identified and enable regulatory requirements to be met and conditions specified in project approvals to be satisfied.

Sufficient data must be collected regarding the behaviour of the sequestered CO_2 for several purposes. Measurement and monitoring of the injection facilities, geological sequestration site, and surrounding environment provide assurance that CO_2 is confined to the storage zone (i.e., containment).

What is a Risk Management Plan?

A risk management plan is a scheme specifying the approach, management components, and resources to be applied to the management of risks. For carbon sequestration projects, the risk management plan specifically addresses the risks associated with CO_2 sequestration at a project site.

Risk is the effect of uncertainty on project objectives, expressed in terms of a combination of the severity of consequence of an event and the associated likelihood of their occurrence.

Risk assessment refers to the overall process of risk identification, risk analysis, and risk evaluation associated with CO_2 sequestration at the specified site. Selection of a suitable site requires comprehensive site characterization and risk assessment. A site can be considered suitable if the site characterization and assessment process has demonstrated that the storage of the CO_2 stream at the candidate site does not pose unacceptable risks to other resources, to the environment and human health and safety, and to project developers, owners, operators, and the Crown (post closure; see *CSA Z741-2012 Geological Storage of Carbon Dioxide* for details).

Proponents submitting applications for the carbon sequestration stage are required to submit satisfactory evidence that the site selected is suitable for the purposes of CO_2 sequestration. The risk management plan is a fundamental component of the MMV requirement for CCS projects. It is recommended that project proponents submit project risk management plans as a separate, standalone appendix within the project's MMV plan.

Key Principles

- Regulatory compliance
- Project specific
- Site specific but also addresses potential cumulative and regional impacts
- Risk based
- Fit for purpose
- Adaptive, with elaboration through successive project stages
- Provide timely warning of CO_2 stream containment and conformance anomalies in order to take appropriate action
- Monitorability in every domain of review (geosphere, hydrosphere, biosphere, and atmosphere)
- Transparency
- Based on sound science and engineering, using best available technologies economically achievable (BATEA)

Objectives

At All Project Stages

- Meet all regulatory requirements set out in applicable legislation and regulation and meet the expectations of the AER as described in directives, bulletins, scheme approvals, and other sources.
- Demonstrate suitability of the site for the purposes of CO_2 sequestration through a site characterization and risk assessment process conducted in accordance with *CSA Z741-12*, its successor, or equivalent standard (see the "Site Suitability and Risk Assessment Requirements" section for further information).
  - Must identify all potential adverse events, assess and quantify the likelihood and potential consequences of their occurrence, and inform project risk-management activities.

  - If the geological containment risk assessment was medium to high and the reservoir is depleted, develop models and include simulation results tracking the fluid and pressure plumes.
  - Particular areas of concern for CO_2 sequestration include assessment of the potential for the following:
    - Existence of faults, known/unknown wells and other zones of weaknesses (e.g., karstic features) that may exist within the area of interest of the storage zone or complex (i.e., the succession of geological and confining formations and their properties—lithology, thickness, extent, and integrity—that contribute to providing secure long-term sequestration of CO_2)
    - Seismicity, both induced and natural
    - Wells in the projected pressure plume area that may present a fluid crossflow risk
    - Altering regional groundwater flow/pressure/chemistry regimes
    - Impacts from CO_2 plume or pressure front on other users of local and regional scale subsurface pore space, including other carbon sequestration operators, oil and gas, minerals, disposal, geothermal, reservoir and salt cavern storage, etc.
    - Affecting nonsaline groundwater
    - Potential impact of existing and new resource development and other activities on the storage zone or complex
- Address health, safety, and environmental risks; evaluate sequestration performance; and provide evidence for long-term safety and security of the storage zone or complex.
  - Potential environmental impacts from CCS operations must be identified in the MMV plan and addressed through mitigation measures and compliance assurance activities.
  - The storage zone or complex is the geological formation or the succession of formations that contribute to providing secure long-term sequestration of CO_2. A complex may include one or more seals and one or more zones that have the potential to sequester CO_2.
- Protect fresh groundwater systems and protect nonsaline groundwater. As part of ensuring there are no adverse impacts to the environment, a groundwater monitoring program (above the base of groundwater protection) must be developed.
  - This program would establish baseline data for nonsaline aquifers, establish that the project will not degrade existing water quality, reduce the risk to the province upon transfer of liability, and help to ensure public and environmental safety.
  - The plan could include industry monitoring wells and domestic monitoring wells where appropriate.

- Monitor and minimize impacts on adjacent saline groundwater systems and other pore-space users, including other CCS, oil and gas, minerals, disposal, geothermal, reservoir and salt cavern storage, etc.
- A hazard assessment of, and monitoring and mitigation program for, induced seismicity must be included as a key component of the MMV plan.
- Set out the MMV and risk-management activities that a project proponent/lessee will undertake while the plan is in effect.

For the Evaluation Stage

During this stage, project developers are expected to collect sufficient data to support the site characterization process, which is meant to provide satisfactory evidence of site suitability for the purposes of CO_2 sequestration.

- Analyze the likelihood that operations/activities under the permit/agreement will interfere with other mineral recovery operations. This is a key requirement of an MMV plan for an evaluation permit, as set out in section 7 of the *Carbon Sequestration Tenure Regulation*.
- Establish anticipated CO_2 storage resource estimates based on the best available data before conducting the evaluation.
- Establish whether the storage zone or complex is a hydrodynamically open or closed system. Hydrodynamics and spill points must be addressed to support containment assurance in open systems.
- Set out the site characterization activities that will be conducted and how these results will inform the site suitability, project risk, and MMV plan requirements of the sequestration stage. Information may include the following:
    - An overview of how information will be gathered and associated timelines
    - Plans to assess monitorability
    - A discussion of the initial risk assessment, as well as plans to undertake a more detailed risk assessment in support of the carbon sequestration stage
    - A legacy well risk assessment that takes into account the selected locations for injection wells and the possible need to upgrade some legacy wells to modern abandonment standards for CO_2 containment
- Operate in compliance with the plan. Per section 7(2) of the *Carbon Sequestration Tenure Regulation*, a permittee must not conduct any operations or activities under the evaluation permit unless an MMV plan has been approved in relation to the permit and the permittee complies with the approved plan.

For the Sequestration Stage

Site Suitability and Risk Management

It is expected that any MMV plans submitted to the AER for approval include a risk management section that is completed in accordance with the requirements of *CSA Z741-12*, its successor, or equivalent standard (e.g., *ISO 27914-2017(E)*, *EU Directive 2009/31/EC*). This risk management process must be implemented during the initial site screening, selection, and characterization periods and must be iteratively repeated in a consistent, transparent, and traceable manner throughout the project life cycle (from site screening/selection up to closure). Comprehensive site characterization, risk assessment, and management are fundamental.

CSA Z741-12 outlines the following required steps in the risk management process:

1) A site screening, selection, and characterization step to identify suitable candidate sites, consisting of the following elements:
    a) Site elimination, consisting of eliminating sites that lack the technical and legal/regulatory characteristics to be considered suitable for CO_2 storage, including the following:
        i) unfavorable capacity, injectivity, containment, seismicity, pore pressure, faulting/ fracturing, structural deformation, hydrodynamic, monitoring, and legacy wellbore characteristics
        ii) within or in communication with protected areas, protected groundwater, natural resources (energy, geothermal, mineral), or restricted pore space rights
    b) Site selection, consisting of assessing the following:
        i) Subsurface criteria, including capacity, injectivity, storage security, pore space ownership, other subsurface activities, other subsurface resources, and need for pressure control
        ii) Surface criteria, including access to CO_2 sources, required infrastructure, population density, land ownership and current/future land use, proximity to environmentally sensitive/reserved/protected areas and bodies of water, topography, weather, cultural, historical, socioeconomic conditions
    c) Site characterization, consisting of the following:
        i) Storage unit geological and hydrogeological characterization
        ii) Confining strata, including primary seal and secondary barriers characterization
        iii) Baseline geochemical characterization for sequestration projects targeting over 200 000 tonnes of CO_2 per year into saline aquifers

iv) Legacy wellbore characterization, which takes into account the proposed locations of injection wells and anticipated extent of CO_2 and pressure plume

d) Modelling for saline aquifers to understand, predict, and communicate the fate and potential impacts of the injected CO_2 and associated pressure increase over the lifetime of the project, including post closure, consisting of the following:

i) Development of a history-matched geological static model describing key geological, hydrogeological, geothermal, and geomechanical features of the storage zone or complex

ii) Flow modelling of the injected CO_2 flow to predict subsurface movement and assess risks and storage capacity

iii) Geochemical modelling, for sequestration into saline aquifers for projects targeting over 200 000 tonnes of CO_2 per year, to evaluate potential effects of injected CO_2 stream on storage container, primary seal, and wellbore materials

iv) Geomechanical modelling of the entire storage unit, storage zone or complex, and the entire overlying sedimentary succession to evaluate potential effects of stress changes and deformation and associated risks

e) For depleted reservoirs, and for projects in saline aquifers injecting less than 200 000 tonnes CO_2 per year, if the geological containment risk assessment was medium to high, include the modelling information described above in 1(d).

2) A risk assessment step, consisting of the following elements:

a) Identification of elements of concern, including human health, safety, the environment and system performance

b) Creation of a conceptual geological static model, which will be used to evaluate the potential behaviour of the storage system. Model must be capable of predicting and describing the performance of the system over time in a manner that provides sufficient technical basis for system risk management

c) Identification of context, including the natural environment, regional natural resources, infrastructure and facilities, human culture, legal and regulatory environment, industry best practices, and project operators/subcontractors

d) A risk management plan that includes the following:

i) Organizational procedures and practices applied to risk management

ii) A schedule for performing iterative risk assessments and activities supporting the risk assessments

iii) Principles and guidelines that will be applied to enhance the thoroughness, accuracy, transparency, and traceability of risk assessments

iv) Elements of concern

v) Project-specific risk-evaluation criteria for each element of concern aligned with the scope and scale of the project in terms of qualitative versus quantitative likelihoods

vi) Risk tolerability and acceptance thresholds for each element of concern, including how threshold acceptability were determined and communicated with the AER

vii) Site specific monitoring plan supporting iterative risk management

viii) Iterative, adaptive, responsive site-specific modelling and simulation program that accounts for the effects of uncertainties in modelling and simulation results

ix) An iterative, adaptive project risk register

x) A schedule and process for updating the risk management plan

e) Assessment of risks, including the following:

i) Risk identification: identification of all scenarios that can carry significant risk

ii) Risk analysis: determination of the likelihood and severity of potential consequences for each risk scenario, based on the best available knowledge and scientific reasoning

iii) Risk evaluation: determination of the level of tolerability and acceptability of the risk

3) A review and documentation step, consisting of the following elements:

a) Review and adjustment (update) of the risk management plan and the risk assessment results as necessary throughout the project life cycle

b) Adequate and consistent documentation of the risk-assessment process to ensure transparency and traceability

4) A risk communication and engagement step, consisting of the following:

a) Communication and engagement regarding project opportunities and risk with both internal and external parties who may be impacted, consistent with the resource applications notification guidelines contained in *Directive 065*

Other

- Analyze the likelihood that operations/activities under the lease/agreement will interfere with other mineral recovery operations, based on the geological interpretations and calculations the lessee is required to submit to the AER pursuant to *Directive 065* in its application for approval of the injection scheme under the Oil and Gas Conservation Act. This is a key requirement of an MMV plan for a sequestration lease, as set out in section 15 of the *Carbon Sequestration Tenure Regulation*.

- Develop a suitable monitoring plan and schedule.
    - Identify monitoring tasks.
    - Screen, evaluate, and select monitoring technologies.
    - Provide the rationale for selection of monitoring technologies. Selected technologies must be able to detect early warning signs of any unexpected loss of containment. This will be updated if the results of the baseline assessment indicate a need for more-specific monitoring technologies.
    - Propose a monitoring schedule.
- Establish appropriate baselines for the selected monitoring technologies:
    - Incorporate all monitoring and baseline data requirements identified by the AER during permitting and approval into the MMV plan.
    - Baselines are needed so that anomalous readings for the selected parameters (e.g., pH, CO_2 concentrations) can be identified and response methodologies employed or technologies used to provide evidence that the anomalies are not the result of a release from the storage zone or complex.
    - Data must be collected for an appropriate period of time to establish a statistical basis for variations in data.
    - Some of the baseline data may be compiled during site selection through a review of existing data from oil and gas exploration and production activities or may be newly gathered data.
- Ensure that the monitoring technologies looking at key project risks have the necessary resolution to establish thresholds for action ("trigger events").

During Operation/Injection Stage

- Operate in compliance with the plan and keep it up to date.
    - Per section 16(1) of the *Carbon Sequestration Tenure Regulation*, an MMV plan will expire on the earlier of the third anniversary of its approval date or the date that the lease is renewed. A lessee must submit a new MMV plan for approval no fewer than 90 days before its expiry date.
    - Per section 17(1) of the *Carbon Sequestration Tenure Regulation*, a lessee must not conduct any operations or activities under a carbon sequestration lease unless an MMV has been approved and is in effect for the lease, and the lessee complies with the approved plan.

- Conduct monitoring to do the following:
  - Demonstrate compliance with legislation (regulations, standards, directives), applications, and approvals.
  - Monitor for trigger events and, if detected, employ associated operating procedures in response.
- Compile monitoring results to do the following:
  - Inform and update the project risk management plan.
  - Inform and optimize project operations.
  - Trigger investigation of nonconformance and mitigation and remediation activities as required.
  - Support the receipt of offset credits.
  - Update simulations and models so actual and predicted behaviour can be compared and the MMV plan can be updated as necessary.
  - Validate model predictive capability throughout the injection period.
- Collect sufficient data needed to do the following:
  - Provide suitable evidence of conformance of CO_2 stream and affected fluids within the storage zone or complex.
  - Provide assurance of geological containment of CO_2 stream and affected fluids within the storage zone or complex.
  - Provide suitable evidence of no significant adverse effects to other pore space users within hydraulically connected saline formations.
  - Provide suitable evidence that there are no significant adverse effects of CO_2 injection on health, the environment, or other resources.
  - Provide suitable evidence of the amount of CO_2 sequestered and to support permanent reduction of greenhouse gases as described in the version of the *TIER Quantification Protocol for the Geological Sequestration of Carbon Dioxide* the project is crediting under at the time of reporting.
  - Verify and update models and simulations annually and use the results to continually inform capacity estimates and conformance verification.
- Monitor threats to containment identified in the project risk assessment and, where loss of containment is confirmed, trigger appropriate mitigation and remediation activities.

- Monitoring technologies are evaluated on a regular basis to do the following:
  - Ensure effectiveness of each technology for the designated task as compared to expectations in the MMV plan.
  - Ensure overlapping technologies are complementary and provide the spectrum of results needed to evaluate sequestration performance.
  - Evaluate technologies in use against advancements so new monitoring techniques are deployed when warranted.
- The MMV plan is periodically renewed and ongoing dialogue is held with the AER to ensure the following:
  - Time-sensitive data are collected when available and to the extent required.
  - Simulations and models incorporate actual results to allow comparison of actual and predicted behaviour and evolve as required to illustrate sequestration performance at closure.

During Closure Period Stage

- Operate in compliance with the plan and keep it up to date (the following apply to MMV plan approved during the sequestration stage)
  - Per section 16(1) of the *Carbon Sequestration Tenure Regulation*, an MMV plan will expire on the earlier of the third anniversary of its approval date or the date that the lease is renewed. A lessee must submit a new MMV plan for approval no fewer than 90 days before its expiry date.
  - Per section 17(1) of the *Carbon Sequestration Tenure Regulation*, a lessee must not conduct any operations or activities under a carbon sequestration lease unless a carbon sequestration lease MMV has been approved and is in effect for the lease, and the lessee complies with the approved plan.
- Continue to monitor all wells and facilities and perform all closure activities in accordance with the regulations.
  - Selected monitoring activities continue to demonstrate sequestration performance and compliance with legislation (e.g., regulations, standards, directives), applications, and approvals. This includes demonstrating compliance with section 119 of the *Mines and Minerals Act*, abandonment of all wells and facilities in accordance with the requirements under the *Oil and Gas Conservation Act* and under Part 9 of the *Mines and Minerals Act*, compliance with the reclamation requirements under the *Environmental Protection and Enhancement Act*, showing that the closure period specified in the regulations has passed, and that the conditions specified in the regulations have been met.

  - Provide evidence to support the issuance of a closure certificate (i.e., meet the requirements of section 120(3) of the *Mines and Minerals Act*, including providing evidence that the captured carbon dioxide is behaving in a stable and predictable manner with no significant risk of future leakage out of the storage zone or complex).

- Collect sufficient data needed to do the following:
  - Provide evidence of conformance of CO_2 stream and affected fluids within the storage zone or complex.
  - Provide assurance of geological containment of CO_2 stream and affected fluids within the storage zone or complex.
  - Provide evidence of no significant adverse effects to other pore space users within hydraulically connected saline formations.
  - Provide evidence that there are no significant adverse effects of CO_2 injection on health, the environment, or other resources.
  - Provide evidence of the amount of CO_2 sequestered and to support permanent reduction of greenhouse gases as described in the version of the *TIER Quantification Protocol for the Geological Sequestration of Carbon Dioxide* the project is crediting under at the time of reporting.
- Verify and update models and simulations annually and use the results to continually inform capacity estimates and conformance verification.
- Monitor threats to containment identified in the project risk assessment and, where loss of containment is confirmed, trigger appropriate mitigation and remediation activities.
- Provide information to the AER when requested regarding appropriate MMV techniques that could be used in the post-closure period.
- Arrangements are made between the AER and project operator for the transfer of any MMV monitoring equipment that the AER requests to be left in place at the point of closure that will not compromise long-term integrity of well abandonments.

Additional Resources

Alberta Department of Energy, 2013, Carbon Capture & Storage: Summary Report of the Regulatory Framework Assessment. *https://open.alberta.ca/dataset/9781460105641/resource/ecab392b-4757-4351-a157-9d5aebedecd0*.

U.S. Department of Energy, 2017, Best practices—monitoring, verification, and accounting (MVA) for geologic storage projects: 2017 Revised Edition, DOE/NETL-2017/1847. *https://www.netl.doe.gov/sites/default/files/2018-10/BPM-MVA-2012.pdf*.

Plains CO_2 Reduction (PCOR) Partnership, 2018, Best Practices Manual – Monitoring for CO_2 Storage. *https://undeerc.org/pcor/assets/PDFs/PCOR-BPM-Monitoring-for-CO2-Storage.pdf*.

Canadian Standards Association, 2012, CSA Group Z741-12 Geologic storage of carbon dioxide: Mississauga, Ontario, October.

International Organization for Standardization, 2017, ISO 27914 Carbon dioxide capture, transportation and geological storage — Geological storage.